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PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

December 5, 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, 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, ER15040482, ER16040337, ER17040335
+++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff Docket No. _______________

Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 South Clinton Ave.
3rd Floor, Suite 314
Trenton, New Jersey 08625-0350

Dear Secretary Camacho-Welch:

Enclosed for filing on behalf of Jersey Central Power & Light Company (“JCP&L”), Atlantic City Electric Company (“ACE”), Public Service Electric and Gas Company (“PSE&G”), and Rockland Electric Company (“RECO”) (collectively, the “EDCs”), enclosed please find an original and ten copies of tariff sheets and supporting exhibits that reflect changes to the PJM Open Access Transmission Tariff (“OATT”) made in response to the annual formula rate update filings made by Mid-Atlantic Interstate Transmission , LLC (“MAIT”) in FERC Docket No. ER17-211-000 and ER17-211-001, Potomac-Appalachian Transmission Highline, L.L.C. (“PATH”) in FERC Docket No. ER08-386-000, Virginia Electric and Power Company (“VEPCo”) in FERC Docket No. ER-08-92-000, AEP East Operating Companies and AEP East Transmission Companies (”AEP”) in FERC Docket No.

ER17-405-000, and by PSE&G in FERC Docket No. ER09-1257-000, as well as the updates to JCP&L's FERC-authorized transmission rate under Docket No. ER17-217-000.

Background

In its Orders dated October 22, 2003 (BPU Docket No. EO03050394) and October 22, 2004 (BPU Docket No. EO04040288), the Board of Public Utilities ("Board") authorized the EDCs to recover FERC-approved changes in firm transmission service-related charges. The Board has also authorized recovery of FERC-approved changes in firm transmission service-related charges in subsequent orders approving the Basic Generation Service ("BGS") supply procurement process and the associated Supplier Master Agreement ("SMA"). In the Board Order dated November 19, 2018 in BPU Docket No. ER18091061, the Board again concluded that such a "pass through" of FERC-approved transmission rate changes was appropriate.

The EDCs' pro-forma tariff sheets, included as Attachment 2a (PSE&G), Attachment 3a (JCP&L), Attachment 4a (ACE), and Attachment 5a (RECO), propose effective dates of January 1, 2019, and specifically reflect changes to BGS rates applicable to Basic Generation Service – Residential Small Commercial Pricing ("BGS-RSCP"), and Commercial and Industrial Energy Pricing ("BGS-CIEP") customers resulting from the MAIT, PATH, VEPCo, AEP, and PSE&G, annual formula rate updates filed with FERC on or about October 5, 2018, September 6, 2018, October 5, 2018, November 1, 2018 and October 16, 2018, respectively. While JCP&L is updating their FERC approved transmission rate for 2019, it is based on the Settlement approved by FERC on December 17, 2017. The specific additional PJM transmission charges related to the JCP&L, MAIT, PATH, VEPCo, AEP, and PSE&G filings are found in Schedule 12 of the PJM OATT. On November 5, 2018, PJM updated its Schedule 12 Transmission Enhancement Worksheet, which, along with Schedule 12 of the PJM OATT, is utilized in developing this filing and incorporates the formula rate updates referenced herein. Because BGS suppliers will begin paying these increased transmission charges in January 2019, the EDCs request a waiver of the 30-day filing requirement.

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

Request for Board Approval

The EDCs respectfully request approval to implement these revised tariff rates effective January 1, 2019. In support of this request, the EDCs have included pro-forma tariff sheets as noted above. The BGS rates have been modified in accordance with the Board-approved methodology contained in each EDC's Company-Specific Addendum in the above-referenced BGS proceedings and in conformance with each EDC's Board-approved BGS tariff sheets.

The determinants for calculation of the PJM charges are set forth in Schedule 12 of the PJM OATT and on the Formula Rates page of the PJM website. Copies of all formula rate updates are attached, but can also be found on the PJM website at: http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx.

Attachment 1 shows the derivation of the PSE&G Network Integration Transmission Service Charge ("Derived NITS Charge") and the JCP&L Derived NITS Charge. The translation of the transmission zone rate impact to the BGS rates of each of the EDCs, assuming implementation on January 1, 2019, is included as Attachments 2, 3, 4, and 5 for PSE&G, JCP&L, ACE, and RECO, respectively. Attachment 6 shows the cost impact for the January through December 2019 period for each of the EDCs. These costs were allocated to the various transmission zones using the cost information from the formula rates for the MAIT, PATH, VEPCo, AEP, and PSE&G projects, and the rate for the JCP&L projects, posted on the PJM website. Attachment 7 provides excerpts of the Schedule 12 OATT indicating the responsible share of projects. Attachments 8, 9, 10, 11, 12 and 13 provide the formula rate updates for MAIT, PATH, AEP, VEPCo, and PSE&G, respectively, as well as the update for JCP&L.

The EDCs also request that BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the MAIT, PATH, VEPCo, AEP, and PSE&G project annual formula updates, as well as the JCP&L rate update, effective on January 1, 2019. Suppliers will be compensated subject to the terms and conditions of the applicable SMAs. Any differences between payments to BGS-RSCP and BGS-CIEP Suppliers and charges to customers will flow through BGS Reconciliation Charges.

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

We thank the Board for all courtesies extended.

Respectfully submitted,

Attachments

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE

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BGS TRANSMISSION ENHANCEMENT CHARGE

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Attachment
1a

Derivation of PSE&G Network Integration Transmission Service (NITS) Charge

Attachment
1b

Derivation of JCP&L Network Integration Transmission Service (NITS) Charge

Attachment 1a PSE&G Network Integration Service Calculation.

Derived Network Integration Service Rate Applicable to PSE&G customers - Effective January 1, 2019 through December 31, 2019

Line #	Description	Rate			Source
(1)	Transmission Service Annual Revenue Requirement	$	1,348,729,822.20		Page 4 of Attachment 12 -Line 164
(2)	Total Schedule 12 TEC Included in above	$	(461,903,158.00)		Attachment 6a Column (a)
(3)	PSE&G Customer Share of Schedule 12 TEC	$	291,644,706.39		Attachment 6a Column (h)
(4)	Total Transmission Costs Borne by PSE&G customers	$	1,178,471,370.58		=(1) +(2) +(3)
(5)	2019 PSE&G Network Service Peak		9,978.3	MW	Page 4 of Attachment 11 - -Line 165
(6)	2019 Derived Network Integration Transmission Service Rate	$	118,103.42	per MW-year	
	Resulting 2019 BGS Firm Transmission Service Supplier Rate	$	323.57	per MW-day	= (6)/365

Attachment 1b JCP&L Network Integration Transmission Service Calculation

Derived Network Integration Transmission Service Rate Applicable to JCP&L customers - Effective January 1, 2019 through December 31, 2019

Line #	Description	Rate			Source
(1)	Transmission Service Annual Revenue Requirement	$	157,627,046		Settlement Agreement in ER17-217-003, sum of provision 2.1a and 2.1b*
(2)	Total Schedule 12 TEC Included in Above	$	(22,627,046)		Settlement Agreement in ER17-217-003, provision 2.1b
(3)	JCP&L Customer Share of Schedule 12 TEC	$	9,028,360		Attachment 6, Column g
(4)	Total Transmission Costs Borne by JCP&L Customers	$	144,028,360		=(1) + (2) + (3)
(5)	2019 JCP&L Network Service Peak		5,976.5	MW	PJM network service peak loads for 2019
(6)	2019 Derived Network Integration Transmission Service Rate	$	24,099.11	per MW-year	
	Resulting 2019 BGS Firm Transmission Service Supplier Rate	$	66.02	per MW-day	= (6)/365

*The settlement agreement in ER17-217-003 specifies (1) JCP&L's annual stated revenue requirement for NITS is $135,000,000 and (2) JCP&L's stated revenue requirement for its projects listed on Schedule 12 of the PJM OATT (that are not included in JCP&L's NITS revenue requirement) is an average of $20 million/year. Effective January 1, 2019, the settlement agreement specifies the annual revenue requirement for TEC is $22,627,046.

Attachment 2 – PSE&G Tariffs and Rate Translation

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 JCP&L Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2d
PSE&G Translation of VEPCo Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2e
PSE&G Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2f
PSE&G Translation of MAIT Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2g
PSE&G Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2a
Pro-forma PSE&G Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 75**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX 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 kilowatt-hour:

	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	$0.121669	$0.129730	$0.121644	$0.129703
RS – in excess of 600 kWh	0.121669	0.129730	0.130740	0.139402
RHS – first 600 kWh	0.095382	0.101701	0.090777	0.096791
RHS – in excess of 600 kWh	0.095382	0.101701	0.102939	0.109759
RLM On-Peak	0.211312	0.225311	0.224139	0.238988
RLM Off-Peak	0.062500	0.066641	0.057411	0.061214
WH	0.049065	0.052316	0.046813	0.049914
WHS	0.049245	0.052507	0.046520	0.049602
HS	0.104103	0.111000	0.106025	0.113049
BPL	0.046908	0.050016	0.041926	0.044704
BPL-POF	0.046908	0.050016	0.041926	0.044704
PSAL	0.046908	0.050016	0.041926	0.044704

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.

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX 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	$ 5.1628
Charge including New Jersey Sales and Use Tax (SUT)	$ 5.5048
Charge applicable in the months of October through May	$ 5.1628
Charge including New Jersey Sales and Use Tax (SUT)	$ 5.5048

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	$118,103.42 per MW per year
EL05-121	$ 20,069.91 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	$ 46.80 per MW per month
Virginia Electric and Power Company	$ 46.75 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 3.47 per MW per month
PPL Electric Utilities Corporation	$ 218.59 per MW per month
American Electric Power Service Corporation	$ 21.45 per MW per month
Atlantic City Electric Company.	$ 9.32 per MW per month
Delmarva Power and Light Company	$ 0.16 per MW per month
Potomac Electric Power Company.	$ 3.24 per MW per month
Baltimore Gas and Electric Company	$ 3.61 per MW per month
Jersey Central Power and Light	$ 69.17 per MW per month
Mid Atlantic Interstate Transmission	$ 16.22 per MW per month
PECO Energy Company	$ 20.34 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$11.9765
Charge including New Jersey Sales and Use Tax (SUT)	$12.7699

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).

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

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	$118,103.42 per MW per year
EL05-121	$ 20,069.91 per MW per year
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PECO Energy Company	$ 20.34 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$11.9765
Charge including New Jersey Sales and Use Tax (SUT)	$12.7699

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

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

Attachment 2b
PSE&G Translation of NITS Charge into Customer Rates

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Attachment 2f
PSE&G Translation of MAIT Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2g
PSE&G Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2B

Network Integration Service Calculation - BGS-RSC
NITS Charges for January 2019 - December 201

			Effective 1/1/19 - 12/31/1				
PSE&G Annual Transmission Service Revenue Requirement	$	1,348,729,822.20					
Total Schedule 12 TEC Included in above	$	(461,903,158.00)					
PSE&G Customer Share of Schedule 12 NITS	$	291,644,706.39					
NITS Charges for Jan 2019 - Dec 2019	$	1,178,471,370.58					
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,978.30					
Term (Months)		12					
OATT rate	$	9,841.95	/MW/month	all values show w/o NJ SUT			
converted to $/MW/yr =	$	118,103.42	/MW/yr	**Jan 19 - Dec 19 NITS Charge**			
	$	82,474.75	/MW/yr	**2015 - 2017 Weighted Average of**	**$ 72,688.29**	**$ 82,516.44**	**$ 92,569.05**
	$	97,969.33	/MW/yr	**2016- 2018 Weighted Average of**	**$ 82,516.44**	**$ 92,569.05**	**$ 118,103.42**
	$	91,513.26	/MW/yr	**Jan 18 - Dec 18 Weighted Average**			
Resulting Increase in Transmission Rate	$	26,590.17	/MW/yr				
Resulting Increase in Transmission Rate	$	2,215.85	/MW/month				

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045.4	114,167.8	209,061.6	1,060.0	19.0	12,369.0	155,848.0	295,094.0
Change in energy charge								
in $/MWh	$ 8.1911	$ 5.0540	$ 9.1321	$ -	$ -	$ 6.0193	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.008191**	**$ 0.005054**	**$ 0.009132**	**$ -**	**$ -**	**$ 0.006019**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	173,881,076		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$	6.7191	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	6.72	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	173,904,027		unrounded	= (6) * (3)
8	Difference due to rounding	$	22,951		unrounded	= (7) - (4)

Attachment 2C

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2019
Calculation of costs and monthly PJM charges for JCP&L

TEC Charges for January 2019 - December 2019	$	8,282,780.12		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,978.30		
Term (Months)		12		
OATT rate	$	69.17	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	830.04	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045.4	114,167.8	209,061.6	1,060.0	19.0	12,369.0	155,848.0	295,094.0
Change in energy charge								
in $/MWh	$ 0.2557	$ 0.1578	$ 0.2851	$ -	$ -	$ 0.1879	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000256**	**$ 0.000158**	**$ 0.000285**	**$ -**	**$ -**	**$ 0.000188**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	5,427,881		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2097	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.21	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	5,434,501		unrounded	= (6) * (3)
8	Difference due to rounding	$	6,620		unrounded	= (7) - (4)

Attachment 2D

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 201
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2019 - Dec 2019	$	5,597,277.90	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,978.3	
Term (Months)		12	
OATT rate	$	46.75	/MW/month
Resulting Increase in Transmission Rate	$	561.00	/MW/yr

all values show w/o NJ SUT

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045.4	114,167.8	209,061.6	1,060.0	19.0	12,369.0	155,848.0	295,094.0
Change in energy charge								
in $/MWh	$ 0.1728	$ 0.1066	$ 0.1927	$ -	$ -	$ 0.1270	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000173**	**$ 0.000107**	**$ 0.000193**	**$ -**	**$ -**	**$ 0.000127**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,078,110.6	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,878,575.4	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	3,668,547		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.1418	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.14	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	3,623,001		unrounded	= (6) * (3)
8	Difference due to rounding	$	(45,547)		unrounded	= (7) - (4)

Attachment 2E

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2019
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2019 - Dec 2019	$	415,040		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,978.3		
Term (Months)		12		
OATT rate	$	3.47	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	41.64	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045.4	114,167.8	209,061.6	1,060.0	19.0	12,369.0	155,848.0	295,094.0
Change in energy charge								
in $/MWh	$ 0.0128	$ 0.0079	$ 0.0143	$ -	$ -	$ 0.0094	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000013**	**$ 0.000008**	**$ 0.000014**	**$ -**	**$ -**	**$ 0.000009**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24078110.63	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	$	25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	272,296.45		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate		0.01052208	/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		258785.7544		unrounded	= (6) * (3)
8	Difference due to rounding		-13510.69765		unrounded	= (7) - (4)

Attachment 2F

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2019
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

TEC Charges for Jan 2019 - December 2019	$	1,941,872		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,978.3		
Term (Months)		12		
OATT rate	$	16.22	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	194.64	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy charge								
in $/MWh	$ 0.059958	$ 0.036995	$ 0.066847	$ -	$ -	$ 0.044061	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000060**	**$ 0.000037**	**$ 0.000067**	**$ -**	**$ -**	**$ 0.000044**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,539.30	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	1,272,809		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0492	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.05	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,293,929		unrounded	= (6) * (3)
8	Difference due to rounding	$	21,119		unrounded	= (7) - (4)

Attachment 2G

Transmission Charge Adjustment - BGS-RSCP
Schedule 12 - Transmission Enhancement Charges for January 2019- December 2019
Calculation of costs and monthly PJM charges for AEP -East Projects

TEC Charges for January 2019 - December 2019	$	2,567,984		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,978.3		
Term (Months)		12		
OATT rate	$	21.45	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	257.40	/MW/yr	

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW		3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh		12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy Charge									
in $/MWh	$	0.079292	$ 0.048924	$ 0.088401	$ -	$ -	$ 0.058268	$ -	$ -
in $/kWh - rounded to 6 places		**0.000079**	**0.000049**	**0.000088**	**0**	**0**	**0.000058**	**0**	**0**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	1,683,216		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0650	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.07	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,811,500		unrounded	= (6) * (3)
8	Difference due to rounding	$	128,284		unrounded	= (7) - (4)

Attachment 3 – JCP&L Tariffs and Rate Translation

Attachment 3a
Pro-forma JCP&L Tariff Sheets

Attachment 3b
JCP&L Translation of NITS Charge into Customer Rates

Attachment 3c
JCP&L Translation of PSE&G Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3d
JCP&L Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3e
JCP&L Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3f
JCP&L Translation of MAIT Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3g
JCP&L Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3a
Pro-forma JCP&L Tariff Sheets

Service Classification RS
Residential Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RS is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RT. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.007973** per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $2.83** per month
Supplemental Customer Charge: $1.47 per month Off-Peak/Controlled Water Heating

2) **Distribution Charge:**

June through September:
$0.015336 per KWH for the first 600 KWH (except Water Heating)
$0.060646 per KWH for all KWH over 600 KWH (except Water Heating)

October through May:
$0.025123 per KWH for all KWH (except Water Heating)

Water Heating Service:
$0.016767 per KWH for all KWH for Off-Peak Water Heating
$0.022085 per KWH for all KWH for Controlled Water Heating

Service Classification RT
Residential Time-of-Day Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RT is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RS. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.007973** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $5.27** per month
Solar Water Heating Credit: $1.32 per month

2) **Distribution Charge:**
$ 0.047006 per KWH for all KWH on-peak for June through September
$ 0.034528 per KWH for all KWH on-peak for October through May
$ 0.021957 per KWH for all KWH off-peak

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
$ 0.000492 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
$ 0.006809 per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Storm Recovery Charge (Rider SRC):**
$ 0.003288 per KWH for all KWH on-peak and off-peak

Service Classification RGT
Residential Geothermal & Heat Pump Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RGT is available for residential customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, who have one of the following types of electric space heating systems as the primary source of heat for such structure or unit and which system meets the corresponding energy efficiency criterion:

Geothermal Systems with Energy Efficiency Ratio (EER) of 13.0 or greater;
Heat Pump Systems with Seasonal Energy Efficiency Ratio (SEER) of 11.0 or greater, and a Heating Season Performance Factor (HSPF) which meets the then current Federal HSPF standards;
Room Unit Heat Pump Systems with Energy Efficiency Ratio (EER) of 9.5 or greater.

Service Classification RGT is not available for customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, which have an electric resistance heating system as the primary source of space heating for such structure or unit.

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge:**
$0.007973 per KWH for all KWH on-peak and off-peak for June through September
$0.007973 per KWH for all KWH for October through May

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $5.27** per month

2) **Distribution Charge:**

June through September:
$0.047006 per KWH for all KWH on-peak
$0.021957 per KWH for all KWH off-peak

October through May:
$0.025123 per KWH for all KWH

Service Classification GS
General Service Secondary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GS is available for general service purposes at secondary voltages not included under Service Classifications RS, RT, RGT or GST.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge:**
$ 0.007973 per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$ 3.15** per month single-phase
$11.30 per month three-phase

Supplemental Customer Charge: **$ 1.47** per month Off-Peak/Controlled Water Heating
$ 2.58 per month Day/Night Service
$11.74 per month Traffic Signal Service

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 6.73 per maximum KW during June through September, in excess of 10 KW
$ 6.27 per maximum KW during October through May, in excess of 10 KW
$ 3.05 per KW Minimum Charge, in excess of 10 KW

Service Classification GST
General Service Secondary Time-Of-Day

APPLICABLE TO USE OF SERVICE FOR: Service Classification GST is available for general Service purposes for commercial and industrial customers establishing demands in excess of 750 KW in two consecutive months during the current 24-month period. Customers which were served under this Service Classification as part of its previous experimental implementation may continue such Service until voluntarily transferring to Service Classification GS.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge: $0.007973** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $30.30** per month single-phase
$43.25 per month three-phase

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 7.12 per maximum KW during June through September
$ 6.65 per maximum KW during October through May
$ 3.10 per KW Minimum Charge

KWH Charge:
$0.004736 per KWH for all KWH on-peak
$0.004736 per KWH for all KWH off-peak

Service Classification GP
General Service Primary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GP is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Single or three-phase service at primary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge: $0.005257** per KWH for all KWH

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $53.36** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 5.57 per maximum KW during June through September
$ 5.16 per maximum KW during October through May
$ 1.89 per KW Minimum Charge

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.35 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.003415 per KWH for all KWH on-peak and off-peak

3) **Non-utility Generation Charge (Rider NGC):**
$ 0.000466 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
$ 0.006809 per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC):**
$ 0.003288 per KWH for all KWH on-peak and off peak

Service Classification GT
General Service Transmission

APPLICABLE TO USE OF SERVICE FOR: Service Classification GT is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Three-phase service at transmission voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).

2) Transmission Charge: **$0.004848** per KWH for all KWH
$0.001174 per KWH for all KWH High Tension Service

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) Customer Charge: $229.23 per month

2) Distribution Charge:

KW Charge: (Demand Charge)
$ 3.57 per maximum KW
$ 0.95 per KW High Tension Service Credit
$ 2.37 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.09 per KW Minimum Charge
$ 0.71 per KW DOD Service Credit
$ 0.46 per KW Minimum Charge Credit

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.34 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.002636 per KWH for all KWH on-peak and off-peak
$0.000936 per KWH High Tension Service Credit
$0.001713 per KWH DOD Service Credit

3) Non-utility Generation Charge (Rider NGC):
$ 0.000457 per KWH for all KWH on-peak and off-peak – excluding High Tension Service
$ 0.000448 per KWH for all KWH on-peak and off-peak – High Tension Service

4) Societal Benefits Charge (Rider SBC):
$ 0.006809 per KWH for all KWH on-peak and off-peak

Service Classification OL
Outdoor Lighting Service

RESTRICTION: Mercury vapor (MV) area lighting is no longer available for replacement and shall be removed from service when existing MV area lighting fails.

APPLICABLE TO USE OF SERVICE FOR: Service Classification OL is available for outdoor flood and area lighting service operating on a standard illumination schedule of 4200 hours per year, and installed on existing wood distribution poles where secondary facilities exist. This Service is not available for the lighting of public streets and highways. This Service is also not available where, in the Company's judgment, it may be objectionable to others, or where, having been installed, it is objectionable to others.

CHARACTER OF SERVICE: Sodium vapor (SV) flood lighting, high pressure sodium (HPS) and mercury vapor (MV) area lighting for limited period (dusk to dawn) at nominal 120 volts.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	HPS Area Lighting	MV Area Lighting	SV Flood Lighting
100	121	42	Not Available	**$ 2.50**	Not Available
175	211	74	Not Available	**$ 2.50**	Not Available
70	99	35	**$10.37**	Not Available	Not Available
100	137	48	**$10.37**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$12.18**
250	293	103	Not Available	Not Available	**$12.80**
400	498	174	Not Available	Not Available	**$13.13**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000492** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.006809** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 24

BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 24**

Service Classification SVL
Sodium Vapor Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification SVL is available for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

Sodium vapor conversions of mercury vapor or incandescent street lights shall be scheduled in accordance with the Company's SVL Conversion Program, and may be limited to no more than 5% of the lamps served under this Service Classification at the end of the previous year.

CHARACTER OF SERVICE: Sodium vapor lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 6.05**	**$ 1.70**	**$ 0.82**
70	85	30	**$ 6.05**	**$ 1.70**	**$ 0.82**
100	121	42	**$ 6.05**	**$ 1.70**	**$ 0.82**
150	176	62	**$ 6.05**	**$ 1.70**	**$ 0.82**
250	293	103	**$ 7.15**	**$ 1.70**	**$ 0.82**
400	498	174	**$ 7.15**	**$ 1.70**	**$ 0.82**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light’s annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000492** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.006809** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light’s monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light’s Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

Service Classification MVL
Mercury Vapor Street Lighting Service

RESTRICTION: Service Classification MVL is in process of elimination and is withdrawn except for the installations of customers receiving Service hereunder on July 21, 1982, and only for the specific premises and class of service of such customer served hereunder on such date.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents. At the option of the Company, Service may also be provided for lighting service on streets, roads or parking areas on municipal or private property where supplied directly from the Company's facilities when such Service is contracted for by the owner or agency operating such property.

CHARACTER OF SERVICE: Mercury vapor lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All charges include Sale and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
100	121	42	**$ 4.22**	**$ 1.60**	**$ 0.81**
175	211	74	**$ 4.22**	**$ 1.60**	**$ 0.81**
250	295	103	**$ 4.22**	**$ 1.60**	**$ 0.81**
400	468	164	**$ 4.57**	**$ 1.60**	**$ 0.81**
700	803	281	**$ 5.54**	**$ 1.60**	**$ 0.81**
1000	1135	397	**$ 5.54**	**$ 1.60**	**$ 0.81**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000492** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.006809** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

Issued: **Effective:**

Filed pursuant to Order of Board of Public Utilities
Docket No. dated

Service Classification ISL
Incandescent Street Lighting Service

RESTRICTION: Service Classification ISL is in process of elimination and is withdrawn except for the installations of customers currently receiving Service, and except for fire alarm and police box lamps provided under Special Provision (c). The obsolescence of this Service Classification's facilities further dictates that Service be discontinued to any installation that requires the replacement of a fixture, bracket or street light pole.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets or roads where required by city, town, county, State or other principal or public agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: Incandescent lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All Charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Billing Month KWH *	Company Fixture	Customer Fixture
105	37	**$ 1.78**	**$ 0.81**
205	72	**$ 1.78**	**$ 0.81**
327	114	**$ 1.78**	**$ 0.81**
448	157	**$ 1.78**	**$ 0.81**
690	242	**$ 1.78**	**$ 0.81**
860	301	**$ 1.78**	**$ 0.81**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000492** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.006809** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

Service Classification LED
LED Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification LED is available for installation of 12 or more LED (light emitting diode) fixtures per request for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

LED conversions of sodium vapor, mercury vapor or incandescent street lights shall be scheduled at the Company's reasonable discretion.

CHARACTER OF SERVICE: LED lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Lamp Wattage	Type	Lumens	Billing Month KWH*	Company Fixture
50	Cobra Head	4000	18	**$ 6.46**
90	Cobra Head	7000	32	**$ 7.14**
130	Cobra Head	11500	46	**$ 8.51**
260	Cobra Head	24000	91	**$ 10.99**
50	Acorn	2500	18	**$ 15.48**
90	Acorn	5000	32	**$ 16.19**
50	Colonial	2500	18	**$ 8.85**
90	Colonial	5000	32	**$ 12.56**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the lamp wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000492** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.006809** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

TERM OF CONTRACT: Ten years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than ten years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

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 **December 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:

TRAILCO-TEC surcharge of **$0.000211** per KWH
Delmarva-TEC surcharge of **$0.000001** per KWH
ACE-TEC surcharge of **$0.000097** per KWH
PEPCO-TEC surcharge of **$0.000014** per KWH
PPL-TEC surcharge of **$0.000808** per KWH
BG&E-TEC surcharge of **$0.000016** per KWH
PECO-TEC surcharge of **$0.000064** per KWH
EL05-121-TEC surcharge of **$0.005884** per KWH

Effective **January 1, 2019**, 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 **$0.002433** per KWH
VEPCO-TEC surcharge of **$0.000186** per KWH
PATH-TEC surcharge of **$0.000016** per KWH
AEP-East-TEC surcharge of **$0.000082** per KWH
MAIT-TEC surcharge of **$0.000069** per KWH

3) BGS Reconciliation Charge per KWH: **$0.000371** (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 **December 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:

	TRAILCO-TEC	Delmarva-TEC	ACE-TEC
GS and GST	**$0.000211**	**$0.000001**	**$0.000097**
GP	**$0.000141**	**$0.000000**	**$0.000065**
GT	**$0.000128**	**$0.000000**	**$0.000059**
GT – High Tension Service	**$0.000032**	**$0.000000**	**$0.000015**

	PEPCO-TEC	PPL-TEC	BG&E-TEC
GS and GST	**$0.000014**	**$0.000808**	**$0.000016**
GP	**$0.000010**	**$0.000540**	**$0.000011**
GT	**$0.000009**	**$0.000492**	**$0.000010**
GT – High Tension Service	**$0.000002**	**$0.000122**	**$0.000002**

	PECO-TEC	EL05-121-TEC
GS and GST	**$0.000064**	**$0.005884**
GP	**$0.000043**	**$0.003926**
GT	**$0.000039**	**$0.003577**
GT – High Tension Service	**$0.000010**	**$0.000883**

Effective **January 1, 2019**, 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	**$0.002433**	**$0.000186**	**$0.000016**
GP	**$0.001604**	**$0.000123**	**$0.000011**
GT	**$0.001480**	**$0.000113**	**$0.000010**
GT – High Tension Service	**$0.000358**	**$0.000028**	**$0.000002**

	AEP-East-TEC	MAIT-TEC
GS and GST	**$0.000082**	**$0.000069**
GP	**$0.000054**	**$0.000046**
GT	**$0.000050**	**$0.000043**
GT – High Tension Service	**$0.000012**	**$0.000011**

4) BGS Reconciliation Charge per KWH: $0.000973 (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
JCP&L Translation of NITS Charge into Customer Rates

Attachment 3c
JCP&L Translation of PSE&G Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3d
JCP&L Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3e
JCP&L Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3f
JCP&L Translation of MAIT Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3g
JCP&L Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3b

Attachment 3b - JCP&L Translation of NITS Charge into BGS Customer Rates (Riders RSCP and CIEP)

NITS Charges for January 2019 through December 2019 - Settlement

JCP&L Annual Transmission Service Revenue Requirements	$ 157,627,046	
Total Schedule 12 TEC Included in Above	$ (22,627,046)	
JCP&L Customer Share of Schedule 12 TEC	$ 9,028,360	
NITS Charges for January 2019 - December 2019	$ 144,028,360	
JCP&L Zonal Transmission Load for 2019	5,976.5	(MW)
2019 NITS Rate	$ 24,099.11	(per MW-yr)
Resulting BGS Firm Transmission Service Supplier Rate	$ 66.02	(per MW-day)
Change in BGS Firm Transmission Service Supplier Rate	$ (2.78)	(per MW-day)

				Effective January 1, 2019:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery	BGS Eligible Sales (kWh)	Transmission Rate ($/kWh)	Transmission Rate w/SUT ($/kWh)
Secondary (excluding lighting)	5,150.8	$ 124,129,721	16,598,859,593	$ 0.007478	$ 0.007973
Primary	363.8	$ 8,767,258	1,778,349,586	$ 0.004930	$ 0.005257
Transmission @ 34.5 kV	306.3	$ 7,381,559	1,623,279,272	$ 0.004547	$ 0.004848
Transmission @ 230 kV	16.2	$ 390,406	354,495,253	$ 0.001101	$ 0.001174
Total	5,837.1	$ 140,668,943	20,354,983,704		

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales January through December @ Customer	15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node	17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,694	MW
4	Change in Transmission Payment to RSCP Suppliers	$ (4,754,483)	= Line 3 x ($2.78) x 365
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$ (0.28)	= Line 4 / Line 2

Attachment 3c

Jersey Central Power & Light Company
Proposed PSEG Project Transmission Enhancement Charge (PSEG-TEC Surcharge) effective January 1, 2019
To reflect FERC-approved PSEG Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2019

2019 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$	3,663,042.76	(1)
2019 JCP&L Zone Transmission Peak Load (MW)		5,976.5	
PSEG-Transmission Enhancement Rate ($/MW-month)	$	612.91	

				Effective January 1, 2019:	
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)	5150.8	37,883,713	16,598,859,593	$ 0.002282	$ 0.002433
Primary	363.8	2,675,382	1,778,349,586	$ 0.001504	$ 0.001604
Transmission @ 34.5 kV	306.3	2,253,155	1,623,279,272	$ 0.001388	$ 0.001480
Transmission @ 230 kV	16.2	118,991	354,495,253	$ 0.000336	$ 0.000358
Total	5837.1	42,931,241	20,354,983,704		

(1) Cost Allocation of PSEG Project Schedule 12 Charges to JCP&L Zone for 2019
(2) Based on 12 months PSEG Project costs from January through December 2019
(3) January 2019 through December 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	PSEG-Transmission Enhancement Costs to RSCP Suppliers	$	34,523,864	= Line 3 x $612.91 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	2.01	= Line 4 / Line 2

Attachment 3d

Jersey Central Power & Light Company
Proposed VEPCO Project Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2019
To reflect FERC-approved VEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2019

2019 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$	279,759.42	(1)
2019 JCP&L Zone Transmission Peak Load (MW)		5,976.5	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$	46.81	

				Effective January 1, 2019:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	VEPCO-TEC Surcharge ($/kWh)	VEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5150.8	2,893,312	16,598,859,593	$ 0.000174	$ 0.000186
Primary	363.8	204,328	1,778,349,586	$ 0.000115	$ 0.000123
Transmission @ 34.5 kV	306.3	172,081	1,623,279,272	$ 0.000106	$ 0.000113
Transmission @ 230 kV	16.2	9,088	354,495,253	$ 0.000026	$ 0.000028
Total	5837.1	3,278,809	20,354,983,704		

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2019
(2) Based on 12 months VEPCO Project costs from January through December 2019
(3) January 2019 through December 2019

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	VEPCO-Transmission Enhancement Costs to RSCP Suppliers	$	2,636,709	= Line 3 x $46.81 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.15	= Line 4 / Line 2

Attachment 3e

Jersey Central Power & Light Company
Proposed PATH Project Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2019
To reflect FERC-approved PATH Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2019

2019 Average Monthly PATH-TEC Costs Allocated to JCP&L Zone	$	24,048.05	(1)
2019 JCP&L Zone Transmission Peak Load (MW)		5,976.5	
PATH-Transmission Enhancement Rate ($/MW-month)	$	4.02	

				Effective January 1, 2019:	
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)	5150.8	248,708	16,598,859,593	$ 0.000015	$ 0.000016
Primary	363.8	17,564	1,778,349,586	$ 0.000010	$ 0.000011
Transmission @ 34.5 kV	306.3	14,792	1,623,279,272	$ 0.000009	$ 0.000010
Transmission @ 230 kV	16.2	781	354,495,253	$ 0.000002	$ 0.000002
Total	5837.1	281,846	20,354,983,704		

(1) Cost Allocation of PATH Project Schedule 12 Charges to JCP&L Zone for 2019
(2) Based on 12 months PATH Project costs from January through December 2019
(3) January 2019 through December 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	PATH-Transmission Enhancement Costs to RSCP Suppliers	$	226,651	= Line 3 x $4.02 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.01	= Line 4 / Line 2

Attachment 3f

Jersey Central Power & Light Company

Proposed MAIT Project Transmission Enhancement Charge (MAIT-TEC Surcharge) effective January 1, 2019

To reflect FERC-approved MAIT Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2019

2019 Average Monthly MAIT-TEC Costs Allocated to JCP&L Zone	$	104,727.08	(1)
2019 JCP&L Zone Transmission Peak Load (MW)		5,976.5	
MAIT-Transmission Enhancement Rate ($/MW-month)	$	17.52	

				Effective January 1, 2019:	
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)	5150.8	1,083,102	16,598,859,593	$ 0.000065	$ 0.000069
Primary	363.8	76,490	1,778,349,586	$ 0.000043	$ 0.000046
Transmission @ 34.5 kV	306.3	64,418	1,623,279,272	$ 0.000040	$ 0.000043
Transmission @ 230 kV	16.2	3,402	354,495,253	$ 0.000010	$ 0.000011
Total	5837.1	1,227,412	20,354,983,704		

(1) Cost Allocation of MAIT Project Schedule 12 Charges to JCP&L Zone for 2019

(2) Based on 12 months MAIT Project costs from January through December 2019

(3) January 2019 through December 2019

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	MAIT-Transmission Enhancement Costs to RSCP Suppliers	$	987,044	= Line 3 x $17.52 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.06	= Line 4 / Line 2

Attachment 3g

Jersey Central Power & Light Company
Proposed AEP-East Project Transmission Enhancement Charge (AEP-East-TEC Surcharge) effective January 1, 2019
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2019

2019 Average Monthly AEP-East-TEC Costs Allocated to JCP&L Zone	$	123,082.50	(1)
2019 JCP&L Zone Transmission Peak Load (MW)		5,976.5	
AEP-East-Transmission Enhancement Rate ($/MW-month)	$	20.59	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective January 1, 2019:** AEP-East-TEC Surcharge ($/kWh)	AEP-East-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5150.8	1,272,937	16,598,859,593	$ 0.000077	$ 0.000082
Primary	363.8	89,896	1,778,349,586	$ 0.000051	$ 0.000054
Transmission @ 34.5 kV	306.3	75,709	1,623,279,272	$ 0.000047	$ 0.000050
Transmission @ 230 kV	16.2	3,998	354,495,253	$ 0.000011	$ 0.000012
Total	5837.1	1,442,540	20,354,983,704		

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2019
(2) Based on 12 months AEP-East Project costs from January through December 2019
(3) January 2019 through December 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	AEP-East-Transmission Enhancement Costs to RSCP Suppliers	$	1,160,042	= Line 3 x $20.59 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.07	= Line 4 / Line 2

Attachment 4 – ACE Tariffs and Rate Translation

Attachment 4a
Pro-forma ACE Tariff Sheets

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

Attachment 4c
ACE Translation of JCP&L Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4d
ACE Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4e
ACE Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4f
ACE Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4a
Pro-forma ACE Tariff Sheets

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

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

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

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000223	0.000186	0.000183	0.000128	0.000104	0.000093	-	0.000090
TrAILCo	0.000276	0.000230	0.000228	0.000159	0.000129	0.000116	-	0.000111
PSE&G	0.000484	0.000403	0.000399	0.000277	0.000226	0.000203	-	0.000194
PATH	0.000018	0.000015	0.000015	0.000011	0.000009	0.000007	-	0.000007
PPL	0.000112	0.000093	0.000092	0.000064	0.000052	0.000047	-	0.000045
PECO	0.000197	0.000164	0.000162	0.000113	0.000093	0.000082	-	0.000079
Pepco	0.000020	0.000017	0.000017	0.000012	0.000010	0.000009	-	0.000009
MAIT	0.000026	0.000021	0.000021	0.000015	0.000012	0.000011		0.000011
JCP&L	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
EL05-121	(0.000814)	(0.000677)	(0.000671)	(0.000468)	(0.000381)	(0.000340)	-	(0.000326)
Delmarva	0.000001	0.000001	0.000001	_	_	_		_
BG&E	0.000001	0.000001	0.000001	–	–	–		–
AEP - East	0.000088	0.000074	0.000074	0.000051	0.000042	0.000037	-	0.000035
Total	0.000635	0.000530	0.000524	0.000364	0.000297	0.000266	-	0.000256

Date of Issue: **Effective Date:**

Issued by:

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

Attachment 4c
ACE Translation of JCP&L Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4d
ACE Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4e
ACE Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4f
ACE Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4b

Atlantic City Electric Company
Proposed PSE&G Projects Transmission Enhancement Charge (PSE&G-TEC Surcharge) effective January 1, 2019
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2019

Transmission Enhancement Costs Allocated to ACE Zone (2019)	$ 276,027
	$ 276,027
2019 ACE Zone Transmission Peak Load (MW)	2,591
Transmission Enhancement Rate ($/MW)	$ 106.52

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (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	1,439	$ 1,839,945	4,059,095,046	$ 0.000453	$ 0.000454	$ 0.000484
MGS Secondary	357	$ 455,800	1,208,290,228	$ 0.000377	$ 0.000378	$ 0.000403
MGS Primary	9	$ 11,235	30,079,842	$ 0.000373	$ 0.000374	$ 0.000399
AGS Secondary	382	$ 487,783	1,873,810,489	$ 0.000260	$ 0.000260	$ 0.000277
AGS Primary	96	$ 122,476	576,381,592	$ 0.000212	$ 0.000212	$ 0.000226
TGS	132	$ 168,614	888,340,177	$ 0.000190	$ 0.000190	$ 0.000203
SPL/CSL	0	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 2,375	13,058,581	$ 0.000182	$ 0.000182	$ 0.000194
	2,416	$ 3,088,227	8,718,499,648			

Atlantic City Electric Company

Proposed JCP&L Projects Transmission Enhancement Charge (JCP&L-TEC Surcharge) effective January 1, 2019

To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2019

Transmission Enhancement Costs Allocated to ACE Zone (2019)	$	1,690
	$	1,690
2019 ACE Zone Transmission Peak Load (MW)		2,591
Transmission Enhancement Rate ($/MW)	$	0.65

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (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	1,439	$ 11,267	4,059,095,046	$ 0.000003	$ 0.000003	$ 0.000003
MGS Secondary	357	$ 2,791	1,208,290,228	$ 0.000002	$ 0.000002	$ 0.000002
MGS Primary	9	$ 69	30,079,842	$ 0.000002	$ 0.000002	$ 0.000002
AGS Secondary	382	$ 2,987	1,873,810,489	$ 0.000002	$ 0.000002	$ 0.000002
AGS Primary	96	$ 750	576,381,592	$ 0.000001	$ 0.000001	$ 0.000001
TGS	132	$ 1,032	888,340,177	$ 0.000001	$ 0.000001	$ 0.000001
SPL/CSL	-	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 15	13,058,581	$ 0.000001	$ 0.000001	$ 0.000001
	2,416	$ 18,910	8,718,499,648			

Atlantic City Electric Company
Proposed VEPCO Projects Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2019
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2019

Transmission Enhancement Costs Allocated to ACE Zone (2019)	$ 127,085
	$ 127,085
2019 ACE Zone Transmission Peak Load (MW)	2,591
Transmission Enhancement Rate ($/MW)	$ 49.04

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (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	1,439	$ 847,123	4,059,095,046	$ 0.000209	$ 0.000209	$ 0.000223
MGS Secondary	357	$ 209,853	1,208,290,228	$ 0.000174	$ 0.000174	$ 0.000186
MGS Primary	9	$ 5,172	30,079,842	$ 0.000172	$ 0.000172	$ 0.000183
AGS Secondary	382	$ 224,578	1,873,810,489	$ 0.000120	$ 0.000120	$ 0.000128
AGS Primary	96	$ 56,389	576,381,592	$ 0.000098	$ 0.000098	$ 0.000104
TGS	132	$ 77,631	888,340,177	$ 0.000087	$ 0.000087	$ 0.000093
SPL/CSL	-	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 1,093	13,058,581	$ 0.000084	$ 0.000084	$ 0.000090
	2,416	$ 1,421,840	8,718,499,648			

Attachment 4e

Atlantic City Electric Company
Proposed PATH Projects Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2019
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2019

Transmission Enhancement Costs Allocated to ACE Zone (2019)	$	10,429
	$	10,429
2019 ACE Zone Transmission Peak Load (MW)		2,591
Transmission Enhancement Rate ($/MW)	$	4.02

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	l. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$ 69,519	4,059,095,046	$ 0.000017	$ 0.000017	$ 0.000018
MGS Secondary	357	$ 17,222	1,208,290,228	$ 0.000014	$ 0.000014	$ 0.000015
MGS Primary	9	$ 424	30,079,842	$ 0.000014	$ 0.000014	$ 0.000015
AGS Secondary	382	$ 18,430	1,873,810,489	$ 0.000010	$ 0.000010	$ 0.000011
AGS Primary	96	$ 4,628	576,381,592	$ 0.000008	$ 0.000008	$ 0.000009
TGS	132	$ 6,371	888,340,177	$ 0.000007	$ 0.000007	$ 0.000007
SPL/CSL	-	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 90	13,058,581	$ 0.000007	$ 0.000007	$ 0.000007
	2,416	$ 116,683	8,718,499,648			

Attachment 4f

Atlantic City Electric Company

Proposed MAIT Projects Transmission Enhancement Charge (MAIT Project-TEC Surcharge) effective January 1, 2019

To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2019

Transmission Enhancement Costs Allocated to ACE Zone (2019)	$ 14,741
	$ 14,741
2019 ACE Zone Transmission Peak Load (MW)	2,591
Transmission Enhancement Rate ($/MW-Month)	$ 5.69

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (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	1,439	$ 98,259	4,059,095,046	$ 0.000024	$ 0.000024	$ 0.000026
MGS Secondary	357	$ 24,341	1,208,290,228	$ 0.000020	$ 0.000020	$ 0.000021
MGS Primary	9	$ 600	30,079,842	$ 0.000020	$ 0.000020	$ 0.000021
AGS Secondary	382	$ 26,049	1,873,810,489	$ 0.000014	$ 0.000014	$ 0.000015
AGS Primary	96	$ 6,541	576,381,592	$ 0.000011	$ 0.000011	$ 0.000012
TGS	132	$ 9,005	888,340,177	$ 0.000010	$ 0.000010	$ 0.000011
SPL/CSL	0	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 127	13,058,581	$ 0.000010	$ 0.000010	$ 0.000011
	2,416	$ 164,921	8,718,499,648			

Attachment 4g

Atlantic City Electric Company
Proposed AEP Projects Transmission Enhancement Charge (AEP Project-TEC Surcharge) effective January 1, 2019
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2019

Transmission Enhancement Costs Allocated to ACE Zone (2019)	$ 50,741
	$ 50,741
2019 ACE Zone Transmission Peak Load (MW)	2,591
Transmission Enhancement Rate ($/MW-Month)	$ 19.58

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2018 - May 2019 (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	1,439	$ 338,233.39	4,059,095,046	$ 0.000083	$ 0.000083	$ 0.000088
MGS Secondary	357	$ 83,789	1,208,290,228	$ 0.000069	$ 0.000069	$ 0.000074
MGS Primary	9	$ 2,065	30,079,842	$ 0.000069	$ 0.000069	$ 0.000074
AGS Secondary	382	$ 89,668	1,873,810,489	$ 0.000048	$ 0.000048	$ 0.000051
AGS Primary	96	$ 22,514	576,381,592	$ 0.000039	$ 0.000039	$ 0.000042
TGS	132	$ 30,996	888,340,177	$ 0.000035	$ 0.000035	$ 0.000037
SPL/CSL	-	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 437	13,058,581	$ 0.000033	$ 0.000033	$ 0.000035
	2,416	$ 567,703	8,718,499,648			

Attachment 5 – RECO Tariffs and Rate Translation

Attachment 5a
Pro-forma RECO Tariff Sheets

Attachment 5b
RECO Translation of PSE&G Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 5c
RECO Translation of JCP&L Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 5d
RECO Translation of VEPCO Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 5e
RECO Translation of PATH Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 5f
RECO Translation of AEP East Schedule 12 (Transmission
Enhancement) Charges into Customer Rates

Attachment 5a
Pro-forma RECO Tariff Sheets

DRAFT

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, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh .... @	1.945 ¢ per kWh	1.945 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and the Temporary Tax Act Credit as described in General Information Section Nos. 33, 34, 35, and 36, respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

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, EL05-121 Settlement and Transmission Enhancement Charges.

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	1.182 ¢ per kWh	1.182 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	1.177 ¢ per kWh	1.177 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Surcharges, and Temporary Tax Act Credit

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit as described in General Information Section Nos. 33, 34, 35, and 36, 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, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh .....@	1.204 ¢ per kWh	1.204 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit as described in General Information Section Nos. 33, 34, 35, and 36, respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

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, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh ……….. @	1.227 ¢ per kWh	1.227 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit

The provisions of the Company’s Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit as described in General Information Section Nos. 33, 34, 35, and 36, 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, EL05-121 Settlement and Transmission Enhancement Charges.

		Primary	High Voltage Distribution
All Periods	All kWh @	0.697 ¢ per kWh	0.697 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit as described in General Information Section Nos. 33, 34, 35, and 36 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 2.883 ¢ per kWh during the billing months of October through May and 4.662 ¢ per kWh during the summer billing months, a Transmission Charge of 0.421 ¢ per kWh and a Transmission Surcharge of 0.697 ¢ 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)

Attachment 5a

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective January 1, 2019
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved BG&E Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PECO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved EL05-121 Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates

(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	$0.00001
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00009	0.00006	0.00006	0.00006	0.00000	0.00006	0.00000	0.00003
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00090	0.00054	0.00056	0.00059	0.00000	0.00057	0.00000	0.00033
PSE&G - TEC	(9)	0.00982	0.00597	0.00579	0.00576	0.00000	0.00616	0.00000	0.00344
TrAILCo - TEC	(10)	0.00019	0.00012	0.00012	0.00013	0.00000	0.00012	0.00000	0.00007
VEPCo - TEC	(11)	0.00021	0.00013	0.00012	0.00012	0.00000	0.00013	0.00000	0.00007
MAIT -TEC	(12)	0.00006	0.00004	0.00004	0.00004	0.00000	0.00004	0.00000	0.00002
JCP&L -TEC	(13)	0.00030	0.00019	0.00018	0.00018	0.00000	0.00019	0.00000	0.00011
PECO -TEC	(14)	0.00008	0.00005	0.00005	0.00005	0.00000	0.00005	0.00000	0.00003
EL05-121	(15)	0.00653	0.00393	0.00407	0.00431	0.00000	0.00414	0.00000	0.00242
Total ($/kWh and excl SUT)		$0.01825	$0.01109	$0.01105	$0.01130	$0.00001	$0.01152	$0.00001	$0.00655
Total (¢/kWh and excl SUT)		1.825 ¢	1.109 ¢	1.105 ¢	1.130 ¢	0.001 ¢	1.152 ¢	0.001 ¢	0.655 ¢

(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	$0.00001
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00010	0.00006	0.00006	0.00006	0.00000	0.00006	0.00000	0.00003
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00096	0.00058	0.00060	0.00063	0.00000	0.00061	0.00000	0.00035
PSE&G - TEC	(9)	0.01047	0.00637	0.00617	0.00614	0.00000	0.00657	0.00000	0.00367
TrAILCo - TEC	(10)	0.00020	0.00013	0.00013	0.00014	0.00000	0.00013	0.00000	0.00007
VEPCo - TEC	(11)	0.00022	0.00014	0.00013	0.00013	0.00000	0.00014	0.00000	0.00007
MAIT -TEC	(12)	0.00006	0.00004	0.00004	0.00004	0.00000	0.00004	0.00000	0.00002
JCP&L -TEC	(13)	0.00032	0.00020	0.00019	0.00019	0.00000	0.00020	0.00000	0.00012
PECO -TEC	(14)	0.00009	0.00005	0.00005	0.00005	0.00000	0.00005	0.00000	0.00003
EL05-121	(15)	0.00696	0.00419	0.00434	0.00460	0.00000	0.00441	0.00000	0.00258
Total ($/kWh and incl SUT)		$0.01945	$0.01182	$0.01177	$0.01204	$0.00001	$0.01227	$0.00001	$0.00697
Total (¢/kWh and incl SUT)		1.945 ¢	1.182 ¢	1.177 ¢	1.204 ¢	0.001 ¢	1.227 ¢	0.001 ¢	0.697 ¢

Notes:

(1) RMR rates based on allocations by transmission zone.
(2) ACE-TEC rates pursuant to the Board's Order dated November 19, 2018 in Docket No. ER18091061.
(3) AEP-East-TEC rates calculated in Attachment 5 of the joint filing.
(4) BG&E-TEC rates pursuant to the Board's Order dated November 19, 2018 in Docket No. ER18091061.
(5) Delmarva-TEC rates pursuant to the Board's Order dated November 19, 2018 in Docket No. ER18091061.
(6) PATH-TEC rates calculated in Attachment 5 of the joint filing.
(7) PEPCO-TEC rates pursuant to the Board's Order dated November 19, 2018 in Docket No. ER18091061.
(8) PPL-TEC rates pursuant to the Board's Order dated November 19, 2018 in Docket No. ER18091061.
(9) PSE&G-TEC rates calculated in Attachment 5 of the joint filing.
(10) TrAILCo-TEC rates pursuant to the Board's Order dated November 19, 2018 in Docket No. ER18091061.
(11) VEPCo-TEC rates calculated in Attachment 5 of the joint filing.
(12) MAIT-TEC rates calculated in Attachment 5 of the joint filing.
(13) JCP&L-TEC rates calculated in Attachment 5 of the joint filing.
(14) PECO-TEC rates pursuant to the Board's Order dated November 19, 2018 in Docket No. ER18091061.
(15) EL05-121 rates pursuant to the Board's Order dated November 19, 2018 in Docket No. ER18091061.

Attachment 5b
RECO Translation of PSE&G Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5c
RECO Translation of JCP&L Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5d
RECO Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5e
RECO Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5f
RECO Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5b

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PSE&G Project) effective January 1, 2019.
To reflect FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2019 to December 2019.

2019 Average Monthly PSE&G-TEC Costs Allocated to RECO	$	916,809	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	2,056.61	
SUT		6.625%	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)		Col.3=Col.2 x $916,809 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales Jan 2019 - Dec 2019 (kWh)		Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)		Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	6,628,057	675,067,000	$	0.00982	$	0.01047
SC2 Secondary	124.9	28.02%	$	3,083,138	516,156,000	$	0.00597	$	0.00637
SC2 Primary	15.7	3.52%	$	387,061	66,836,000	$	0.00579	$	0.00617
SC3	0.1	0.02%	$	1,740	302,000	$	0.00576	$	0.00614
SC4	0.0	0.00%	$	-	6,334,000	$	-	$	-
SC5	3.6	0.81%	$	89,263	14,493,000	$	0.00616	$	0.00657
SC6	0.0	0.00%	$	-	5,552,000	$	-	$	-
SC7	32.9	7.38%	$	812,449	235,896,000	$	0.00344	$	0.00367
Total	445.8 (2)	100.00%	$	11,001,708	1,520,636,000				

(1) Attachment 6a - Cost Allocation of PSE&G Project Schedule 12 Charges to RECO Zone for the period January 2019 to December 2019.
(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)		1,235,896	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,150,504	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	10,197,993.45	= Line 3 x $2056.61 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	8.86	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (JCP&L) effective January 1, 2019.
To reflect FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2019 to December 2019

2019 Average Monthly JCP&L-TEC Costs Allocated to RECO	$	28,430	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	63.78	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $28,430 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Jan 2019 - Dec 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	205,535	675,067,000	$	0.00030	$	0.00032
SC2 Secondary	124.9	28.02%	$	95,607	516,156,000	$	0.00019	$	0.00020
SC2 Primary	15.7	3.52%	$	12,003	66,836,000	$	0.00018	$	0.00019
SC3	0.1	0.02%	$	54	302,000	$	0.00018	$	0.00019
SC4	0.0	0.00%	$	-	6,334,000	$	-	$	-
SC5	3.6	0.81%	$	2,768	14,493,000	$	0.00019	$	0.00020
SC6	0.0	0.00%	$	-	5,552,000	$	-	$	-
SC7	32.9	7.38%	$	25,194	235,896,000	$	0.00011	$	0.00012
Total	445.8 (2)	100.00%	$	341,161	1,520,636,000				

(1) Attachment 6b - Cost Allocation of JCP&L Schedule 12 Charges to RECO Zone for the period January 2019 to December 2019
(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)		1,235,896	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,150,504	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	316,262.21	= Line 3 x $63.78 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.27	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (VEPCo) effective January 1, 2019.
To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2019 to December 2019.

2019 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	19,373	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	43.46	
SUT		6.625%	

	Col. 1		Col. 2		Col.3=Col.2 x $19,373 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)		Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Jan 2019 - Dec 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6		60.25%	$	140,056	675,067,000	$	0.00021	$	0.00022
SC2 Secondary	124.9		28.02%	$	65,149	516,156,000	$	0.00013	$	0.00014
SC2 Primary	15.7		3.52%	$	8,179	66,836,000	$	0.00012	$	0.00013
SC3	0.1		0.02%	$	37	302,000	$	0.00012	$	0.00013
SC4	0.0		0.00%	$	-	6,334,000	$	-	$	-
SC5	3.6		0.81%	$	1,886	14,493,000	$	0.00013	$	0.00014
SC6	0.0		0.00%	$	-	5,552,000	$	-	$	-
SC7	32.9		7.38%	$	17,168	235,896,000	$	0.00007	$	0.00007
Total	445.8	(2)	100.00%	$	232,475	1,520,636,000				

(1) Attachment 6c - Cost Allocation of VEPCo Schedule 12 Charges to RECO Zone for the period January 2019 to December 2019.
(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)		1,235,896	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,150,504	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	215,502.60	= Line 3 x $43.46 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.19	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PATH) effective January 1, 2019.
To reflect FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2019 to December 2019.

2019 Average Monthly PATH-TEC Costs Allocated to RECO	$	1,329	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	2.98	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $1,329 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Jan 2019 - Dec 2019 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$ 9,608	675,067,000	$ 0.00001	$ 0.00001
SC2 Secondary	124.9	28.02%	$ 4,469	516,156,000	$ 0.00001	$ 0.00001
SC2 Primary	15.7	3.52%	$ 561	66,836,000	$ 0.00001	$ 0.00001
SC3	0.1	0.02%	$ 3	302,000	$ 0.00001	$ 0.00001
SC4	0.0	0.00%	$ -	6,334,000	$ -	$ -
SC5	3.6	0.81%	$ 129	14,493,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	5,552,000	$ -	$ -
SC7	32.9	7.38%	$ 1,178	235,896,000	$ -	$ -
Total	445.8 (2)	100.00%	$ 15,948	1,520,636,000		

(1) Attachment 6d - Cost Allocation of PATH Project Schedule 12 Charges to RECO Zone for the period January 2019 to December 2019.
(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)		1,235,896	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,150,504	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	14,776.75	= Line 3 x $2.98 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Attachment 5f

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (MAIT) effective January 1, 2019.
To reflect FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2019 to December 2019.

2019 Average Monthly MAIT-TEC Costs Allocated to RECO	$	5,649	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	12.67	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $5,649 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Jan 2019 - Dec 2019 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$ 40,841	675,067,000	$ 0.00006	$ 0.00006
SC2 Secondary	124.9	28.02%	$ 18,998	516,156,000	$ 0.00004	$ 0.00004
SC2 Primary	15.7	3.52%	$ 2,385	66,836,000	$ 0.00004	$ 0.00004
SC3	0.1	0.02%	$ 11	302,000	$ 0.00004	$ 0.00004
SC4	0.0	0.00%	$ -	6,334,000	$ -	$ -
SC5	3.6	0.81%	$ 550	14,493,000	$ 0.00004	$ 0.00004
SC6	0.0	0.00%	$ -	5,552,000	$ -	$ -
SC7	32.9	7.38%	$ 5,006	235,896,000	$ 0.00002	$ 0.00002
Total	445.8 (2)	100.00%	$ 67,791	1,520,636,000		

(1) Attachment 6e - Cost Allocation of MAIT Schedule 12 Charges to RECO Zone for the period January 2019 to December 2019.
(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)		1,235,896	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,150,504	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	62,826.00	= Line 3 x $12.67 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.05	= Line 4/Line 2

Attachment 5g

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP East) effective January 1, 2019.
To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2019 to December 2019.

2019 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	8,842	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	19.83	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $8,842 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Jan 2019 - Dec 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	63,923	675,067,000	$	0.00009	$	0.00010
SC2 Secondary	124.9	28.02%	$	29,735	516,156,000	$	0.00006	$	0.00006
SC2 Primary	15.7	3.52%	$	3,733	66,836,000	$	0.00006	$	0.00006
SC3	0.1	0.02%	$	17	302,000	$	0.00006	$	0.00006
SC4	0.0	0.00%	$	-	6,334,000	$	-	$	-
SC5	3.6	0.81%	$	861	14,493,000	$	0.00006	$	0.00006
SC6	0.0	0.00%	$	-	5,552,000	$	-	$	-
SC7	32.9	7.38%	$	7,836	235,896,000	$	0.00003	$	0.00003
Total	445.8 (2)	100.00%	$	106,105	1,520,636,000				

(1) Attachment 6f - Cost Allocation of AEP East Schedule 12 Charges to RECO Zone for the period January 2019 to December 2019.
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,235,896	MWH
2	BGS-RSCP Eligible Sales Jun - may @ trans node (RECO Eastern Division)		1,150,504	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	98,329.88	= Line 3 x $19.83 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.09	= Line 4/Line 2

Attachment 6 – PJM Schedule 12 (Transmission Enhancement) Charges

Attachment 6a
PSE&G Project Charges

Attachment 6b
JCP&L Project Charges

Attachment 6c
Virginia Electric Power Company Project Charges

Attachment 6d
Potomac-Appalachian Transmission Highline Project Charges

Attachment 6e
Mid Atlantic Interstate Transmission Project Charges

Attachment 6f
AEP Ease Project Charges

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019
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 2019 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*								
Replace all derated Branchburg 500/230 kava transformers	b0130	$ 1,858,024.00	1.36%	47.76%	50.88%	0.00%	$25,269	$887,392	$945,363	$0	$1,858,024
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 757,649.00	0.00%	51.11%	45.96%	2.93%	$0	$387,234	$348,215	$22,199	$757,649
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 8,103,694.00	0.00%	73.45%	21.78%	4.77%	$0	$5,952,163	$1,764,985	$386,546	$8,103,694
Install 230-138kV transformer at Metuchen substation	b0161	$ 2,500,607.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$2,495,606	$5,001	$2,500,607
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 1,541,499.00	1.76%	26.50%	60.89%	0.00%	$27,130	$408,497	$938,619	$0	$1,374,246
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 673,790.00	0.00%	42.95%	38.36%	0.79%	$0	$289,393	$258,466	$5,323	$553,182
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 1,322.00	1.66%	3.74%	6.26%	0.26%	$22	$49	$83	$3	$158
Replace wave trap at Branchburg 500kV substation	b0172.2_dfax	$ 1,322.00	5.32%	33.44%	53.73%	2.16%	$70	$442	$710	$29	$1,251
Replace both 230/138 kV transformers at Roseland	b0274	$ -	0.00%	0.00%	100.00%	0.00%	$0	$0	$0	$0	$0
Branchburg 400 MVAR Capacitor	b0290	$ 3,829,871.50	1.66%	3.74%	6.26%	0.26%	$63,576	$143,237	$239,750	$9,958	$456,521
Branchburg 400 MVAR Capacitor	b0290_dfax	$ 3,829,871.50	5.32%	33.44%	53.73%	2.16%	$203,749	$1,280,709	$2,057,790	$82,725	$3,624,973
Inst Conemaugh 250 MVAR Cap	b0376	$ 138,488.50	1.66%	3.74%	6.26%	0.26%	$2,299	$5,179	$8,669	$360	$16,508
Inst Conemaugh 250 MVAR Cap	b0376_dfax	$ 138,488.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 2,058,054.00	47.01%	7.04%	22.31%	0.00%	$967,491	$144,887	$459,152	$0	$1,571,530
Saddle Brook - Athenia Upgrade Cable	b0472	$ 1,510,913.00	0.00%	0.00%	96.40%	3.60%	$0	$0	$1,456,520	$54,393	$1,510,913
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 41,803,578.50	1.66%	3.74%	6.26%	0.26%	$693,939	$1,563,454	$2,616,904	$108,689	$4,982,987
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489_dfax	$ 41,803,578.50	0.00%	39.91%	54.05%	2.18%	$0	$16,683,808	$22,594,834	$911,318	$40,189,960
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	$ 4,642,115.00	5.14%	33.04%	41.10%	1.53%	$238,605	$1,533,755	$1,907,909	$71,024	$3,751,293
Susquehanna Roseland Breakers (In-Service)	b0489.5	$ 316,103.50	1.66%	3.74%	6.26%	0.26%	$5,247	$11,822	$19,788	$822	$37,680
Susquehanna Roseland Breakers (In-Service)	b0489.5_dfax	$ 316,103.50	0.00%	39.91%	54.05%	2.18%	$0	$126,157	$170,854	$6,891	$303,902
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 1,307,362.50	1.66%	3.74%	6.26%	0.26%	$21,702	$48,895	$81,841	$3,399	$155,838

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019
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 2019 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*								
Loop the 5021 circuit into New Freedom 500 kV substation	b0498_dfax	$ 1,307,362.50	9.56%	26.03%	41.34%	1.66%	$124,984	$340,306	$540,464	$21,702	$1,027,456
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 1,953,476.00	0.00%	36.35%	43.24%	1.61%	$0	$710,089	$844,683	$31,451	$1,586,223
Somerville -Bridgewater Reconductor	b0668	$ 673,790.00	0.00%	39.41%	38.76%	1.45%	$0	$265,541	$261,161	$9,770	$536,472
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 929,810.00	0.00%	9.92%	83.73%	3.12%	$0	$92,237	$778,530	$29,010	$899,777
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 4,877,498.00	0.00%	23.49%	67.03%	2.50%	$0	$1,145,724	$3,269,387	$121,937	$4,537,049
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 2,116,445.00	0.00%	29.27%	65.42%	2.55%	$0	$619,483	$1,384,578	$53,969	$2,058,031
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,198,195.00	0.00%	29.44%	65.25%	2.55%	$0	$647,149	$1,434,322	$56,054	$2,137,525
West Orange Conversion (North Central Reliability)	b1154	$ 39,660,576.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$38,145,542	$1,515,034	$39,660,576
Branchburg-Middlesex Sw Rack	b1155	$ 6,067,491.00	0.00%	4.61%	91.75%	3.64%	$0	$279,711	$5,566,923	$220,857	$6,067,491
Conversion	b1156	$ 38,578,560.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$37,104,859	$1,473,701	$38,578,560
Reconf Kearny Loop in P2216	b1589	$ 2,614,466.00	0.00%	0.00%	77.16%	3.08%	$0	$0	$2,017,322	$80,526	$2,097,848
230kV Lawrence Switching Station Upgrade	b1228	$ 2,293,406.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$2,205,798	$87,608	$2,293,406
Ridge Rd 69kV Breaker Station	b1255	$ 5,035,294.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$4,842,946	$192,348	$5,035,294
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 71,245,300.00	0.28%	1.43%	85.73%	3.40%	$199,487	$1,018,808	$61,078,596	$2,422,340	$64,719,231
Mickleton-Gloucester-Camden	b1398-b1398.7	$ 48,786,513.00	0.00%	13.03%	31.99%	1.27%	$0	$6,356,883	$15,606,806	$619,589	$22,583,277
Aldene-Springfield Rd. Conv	b1399	$ 7,961,344.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$7,657,221	$304,123	$7,961,344
Replace Salem 500 kV breakers	b1410-b1415	$ 850,425.00	1.66%	3.74%	6.26%	0.26%	$14,117	$31,806	$53,237	$2,211	$101,371
Replace Salem 500 kV breakers	b1410-b1416_dfax	$ 850,425.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$817,514	$32,911	$850,425
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 1,346,337.00	0.00%	10.48%	55.03%	2.19%	$0	$141,096	$740,889	$29,485	$911,470
Upgrade Camden Richmon 230kV	b1590	$ 1,246,839.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 3,644,836.00	4.97%	44.34%	48.23%	1.93%	$181,148	$1,616,120	$1,757,904	$70,345	$3,625,518
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,191,349.00	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,339,133	$53,469	$1,392,602
Reconfigure Brunswick New 69kV	b2146	$ 19,937,097.00	0.00%	0.00%	96.16%	3.84%	$0	$0	$19,171,512	$765,585	$19,937,097
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10_dfax	$ 10,097,327.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$10,097,328	$0	$10,097,328
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 10,097,327.50	1.66%	3.74%	6.26%	0.26%	$167,616	$377,640	$632,093	$26,253	$1,203,601
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21_dfax	$ 4,405,930.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$4,405,930	$0	$4,405,930
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 4,405,930.00	1.66%	3.74%	6.26%	0.26%	$73,138	$164,782	$275,811	$11,455	$525,187
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22_dfax	$ 2,624,716.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$2,624,717	$0	$2,624,717
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 2,624,716.50	1.66%	3.74%	6.26%	0.26%	$43,570	$98,164	$164,307	$6,824	$312,866

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019
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 2019 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*								
Construct New Bayway-Bayonne 345kV Circuit	b2436.33	$ -	0.00%	0.00%	100.00%	0.00%	$0	$0	$0	$0	$0
Construct New North Ave-Bayonne 345kV Circuit	b2436.34	$ -	0.00%	0.00%	100.00%	0.00%	$0	$0	$0	$0	$0
Construct North Ave-Airport 345kV Circuit and Substation Upgrades	b2436.50	$ -	0.00%	0.00%	100.00%	0.00%	$0	$0	$0	$0	$0
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	$ 5,387,635.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$5,179,134	$208,501	$5,387,635
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (CWIP)	b2436.70	$ -	0.00%	0.00%	100.00%	0.00%	$0	$0	$0	$0	$0
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81_dfax	$ 3,120,899.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$3,000,121	$120,779	$3,120,900
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81	$ 3,120,899.50	1.66%	3.74%	6.26%	0.26%	$51,807	$116,722	$195,368	$8,114	$372,011
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83_dfax	$ 3,120,899.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$3,000,121	$120,779	$3,120,900
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 3,120,899.50	1.66%	3.74%	6.26%	0.26%	$51,807	$116,722	$195,368	$8,114	$372,011
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84_dfax	$ 3,100,025.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,980,054	$119,971	$3,100,025
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 3,100,025.00	1.66%	3.74%	6.26%	0.26%	$51,460	$115,941	$194,062	$8,060	$369,523
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85_dfax	$ 3,181,353.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$3,058,235	$123,118	$3,181,353
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 3,181,353.00	1.66%	3.74%	6.26%	0.26%	$52,810	$118,983	$199,153	$8,272	$379,217
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90_dfax	$ 1,785,346.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,716,254	$69,093	$1,785,347
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 1,785,346.50	1.66%	3.74%	6.26%	0.26%	$29,637	$66,772	$111,763	$4,642	$212,813
New Bergen 345/230 kV transformer and any associated substation upgrades	b2437.10	$ 3,305,305.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$3,177,390	$127,915	$3,305,305
New Bergen 345/138 kV transformer #1 and any associated substation upgrades	b2437.11	$ -	0.00%	0.00%	100.00%	0.00%	$0	$0	$0	$0	$0
New Bayway 345/138 kV transformer #1 and any associated substation upgrades	b2437.20	$ 1,916,760.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,842,581	$74,179	$1,916,760

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019 **Attachment 6a**

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 2019 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*								
New Bayway 345/138 kV transformer #2 and any associated substation upgrades	b2437.21	$ 1,916,386.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,842,222	$74,164	$1,916,386
New Linden 345/230 kV transformer and any associated substation upgrades	b2437.30	$ 397,348.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$381,971	$15,377	$397,348
Install two 175 MVAR Re at Hptcg	b2702_dfax	$ 1,303,729.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,303,730	$0	$1,303,730
Install two 175 MVAR Re at Hptcg	b2702	$ 1,303,729.50	1.66%	3.74%	6.26%	0.26%	$21,642	$48,759	$81,613	$3,390	$155,405
Totals		**$ 461,903,158.00**					**$3,312,324**	**$43,956,513**	**$291,644,706**	**$11,001,708**	**$349,915,252**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) +

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2019**	**2019 Trans. Peak Load** [2]	**Rate in $/MW-mo.** [1]	**2019 Impact (12 months)**	
PSE&G	$ 24,303,725.53	9,978.3	$ 2,435.66	$ 291,644,706	
JCP&L	$ 3,663,042.76	5,976.5	$ 612.91	$ 43,956,513	
ACE	$ 276,027.04	2,591.3	$ 106.52	$ 3,312,324	
RE	$ 916,809.02	414.8	$ 2,210.24	$ 11,001,708	
Total Impact on NJ Zones	**$ 29,159,604.36**	**18,960.9**		**$ 349,915,252**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

Notes:

1) Uncompressed rate - assumes implementation on January 1, 2019

2) Data on PJM website

Attachment 6b - PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019
Calculation of Costs and Monthly PJM charges for JCP&L Projects

Attachment 6b

		(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 2019 Annual Revenue Requirement** *per Settlement*	**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**
Upgrade the Portland - Greystone 230kV circuit	b0174	$ 1,235,637	0.00%	35.98%	55.27%	2.99%	$0	$444,582	$682,937	$36,946	$1,164,464
Reconductor the 8 mile Gilbert - Glen Gardner 230kV circuit	b0268	$ 628,066	0.00%	62.43%	33.08%	1.46%	$0	$392,102	$207,764	$9,170	$609,036
Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 827,854	2.45%	97.55%	0.00%	0.00%	$20,282	$807,572	$0	$0	$827,854
Build a new 230kV circuit from Larrabee to Oceanview	b2015	$ 19,935,489	0.00%	37.04%	37.08%	1.48%	$0	$7,384,105	$7,392,079	$295,045	$15,071,230
Totals		**$ 22,627,046**					**$20,282**	**$9,028,360**	**$8,282,780**	**$341,161**	**$17,672,584**

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2019**	**2019 Trans. Peak Load ^{2}**	**Rate in $/MW-mo. ^{1}**	**2019 Impact (12 months)**	
PSE&G	$ 690,232	9,978.3	$ 69.17	$ 8,282,780	
JCP&L	$ 752,363	5,976.5	$ 125.89	$ 9,028,360	
ACE	$ 1,690	2,591.3	$ 0.65	$ 20,282	
RE	$ 28,430	414.8	$ 68.54	$ 341,161	
Total Impact on NJ Zones	**$ 1,472,715**	**18,960.9**		**$ 17,672,584**	
			= (k) / (l)	= (k) *12	

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2019
2) Data on PJM website

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019
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	**PJM Upgrade ID**	**Jan - Dec 2019 Annual Revenue Requirement**	**ACE Zone Share**	**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**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
Upgrade Mt Storm - Doubs 500kV	b0217	$108,134.00	1.66%	3.74%	6.26%	0.26%	$1,795	$4,044	$6,769	$281	$12,890
Upgrade Mt Storm - Doubs 500kV	b0217_dfax	$108,134.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Loudoun 150 MVA capacitor @ 500 kV	b0222	$88,996.50	1.66%	3.74%	6.26%	0.26%	$1,477	$3,328	$5,571	$231	$10,608
Loudoun 150 MVA capacitor @ 500 kV	b0222_dfax	$88,996.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breakers and bus work at Suffolk	b0231	$1,244,954.50	1.66%	3.74%	6.26%	0.26%	$20,666	$46,561	$77,934	$3,237	$148,399
500 kV breakers and bus work at Suffolk	b0231_dfax	$1,244,954.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Meadowbrook-Loudon 500kV circuit	b0328.1	$13,345,154.50	1.66%	3.74%	6.26%	0.26%	$221,530	$499,109	$835,407	$34,697	$1,590,742
Meadowbrook-Loudon 500kV circuit	b0328.1_dfax	$13,345,154.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Mt. Storm 500 KV Substation	b0328.3	$805,711.50	1.66%	3.74%	6.26%	0.26%	$13,375	$30,134	$50,438	$2,095	$96,041
Upgrade Mt. Storm 500 KV Substation	b0328.3_dfax	$805,711.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Loudoun 500 KV Substation	b0328.4	$184,145.00	1.66%	3.74%	6.26%	0.26%	$3,057	$6,887	$11,527	$479	$21,950
Upgrade Loudoun 500 KV Substation	b0328.4_dfax	$184,145.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B	$9,632,988.00	1.66%	3.74%	6.26%	0.26%	$159,908	$360,274	$603,025	$25,046	$1,148,252
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B_dfax	$9,632,988.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$2,267,941.00	0.71%	0.00%	0.00%	0.00%	$16,102	$0	$0	$0	$16,102
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$19,388,647.50	1.66%	3.74%	6.26%	0.26%	$321,852	$725,135	$1,213,729	$50,410	$2,311,127
Rebuild Mt Storm-Doubs 500 KV circuit	b1507_dfax	$19,388,647.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$6,117.50	1.66%	3.74%	6.26%	0.26%	$102	$229	$383	$16	$729
Replace wave traps on Dooms-Lexington 500KV circuit	b0457_dfax	$6,117.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T573	b1647	$933.50	1.66%	3.74%	6.26%	0.26%	$15	$35	$58	$2	$111
Morrisville H1T573	b1647_dfax	$933.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T545	b1648	$933.50	1.66%	3.74%	6.26%	0.26%	$15	$35	$58	$2	$111
Morrisville H2T545	b1648_dfax	$933.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T580	b1649	$49,259.00	1.66%	3.74%	6.26%	0.26%	$818	$1,842	$3,084	$128	$5,872
Morrisville H1T580	b1649_dfax	$49,259.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T569	b1650	$49,259.00	1.66%	3.74%	6.26%	0.26%	$818	$1,842	$3,084	$128	$5,872
Morrisville H2T569	b1650_dfax	$49,259.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$4,245.00	1.66%	3.74%	6.26%	0.26%	$70	$159	$266	$11	$506
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784_dfax	$4,245.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019 **Attachment 6c**
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	**PJM Upgrade ID**	**Jan - Dec 2019 Annual Revenue Requirement**	**ACE Zone Share**	**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**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$614,054.00	1.75%	0.71%	0.00%	0.00%	$10,746	$4,360	$0	$0	$15,106
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$1,980,157.00	0.22%	0.00%	0.00%	0.00%	$4,356	$0	$0	$0	$4,356
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	$92,924.50	1.66%	3.74%	6.26%	0.26%	$1,543	$3,475	$5,817	$242	$11,077
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188_dfax	$92,924.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breaker at Brambleton	b1698.1	$0.00	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
501 kV breaker at Brambleton	b1698.1_dfax	$0.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 2 500kV breakers at Chancellor 500 kV	b0756.1	$242,211.00	1.66%	3.74%	6.26%	0.26%	$4,021	$9,059	$15,162	$630	$28,872
Install 2 500kV breakers at Chancellor 500 kV	b0756.1_dfax	$242,211.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$1,074,746.50	1.66%	3.74%	6.26%	0.26%	$17,841	$40,196	$67,279	$2,794	$128,110
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797_dfax	$1,074,746.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798	$6,602,302.50	1.66%	3.74%	6.26%	0.26%	$109,598	$246,926	$413,304	$17,166	$786,994
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798_dfax	$6,602,302.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$1,555,388.50	1.66%	3.74%	6.26%	0.26%	$25,819	$58,172	$97,367	$4,044	$185,402
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799_dfax	$1,555,388.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$2,193,040.50	1.66%	3.74%	6.26%	0.26%	$36,404	$82,020	$137,284	$5,702	$261,410
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805_dfax	$2,193,040.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$607,357.50	1.66%	3.74%	6.26%	0.26%	$10,082	$22,715	$38,021	$1,579	$72,397
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1_dfax	$607,357.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Lexington-Dooms 500 kV Line	b1908	$8,396,013.50	1.66%	3.74%	6.26%	0.26%	$139,374	$314,011	$525,590	$21,830	$1,000,805
Rebuild Lexington-Dooms 500 kV Line	b1908_dfax	$8,396,013.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Surry 500 kV Station Work	b1905.2	$108,098.00	1.66%	3.74%	6.26%	0.26%	$1,794	$4,043	$6,767	$281	$12,885
Surry 500 kV Station Work	b1905.2_dfax	$108,098.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837	$41,841.00	1.66%	3.74%	6.26%	0.26%	$695	$1,565	$2,619	$109	$4,987
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837_dfax	$41,841.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019

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 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**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**
			per PJM Open Access Transmission Tariff								
Uprate Section between Possum and Dumfries Substation	b1328	$500,243.00	0.66%	0.00%	0.00%	0.00%	$3,302	$0	$0	$0	$3,302
Rebuild Loudoun - Brambleto 500kV	b1694	$3,348,111.00	1.66%	3.74%	6.26%	0.26%	$55,579	$125,219	$209,592	$8,705	$399,095
Rebuild Loudoun - Brambleto 500kV	b1694_dfax	$3,348,111.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$970,271.00	1.66%	3.74%	6.26%	0.26%	$16,106	$36,288	$60,739	$2,523	$115,656
Surry to Skiffes Creek 500kV Line	b1905.1	$8,566,778.00	1.66%	3.74%	6.26%	0.26%	$142,209	$320,397	$536,280	$22,274	$1,021,160
Surry to Skiffes Creek 500kV Line	b1905.1_dfax	$8,566,778.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install Breaker and half scheme with minimum of eight 230kV Breakers	b1696	$1,358,286.00	0.46%	0.64%	0.00%	0.00%	$6,248	$8,693	$0	$0	$14,941
Build a second Loudon - Brambleton 500kV line	b2373	$2,799,952.50	1.66%	3.74%	6.26%	0.26%	$46,479	$104,718	$175,277	$7,280	$333,754
Build a second Loudon - Brambleton 500kV line	b2374_dfax	$2,799,952.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Carson Rogers 500kV Ckt	b2744	$7,904,870.00	1.66%	3.74%	6.26%	0.26%	$131,221	$295,642	$494,845	$20,553	$942,261
Totals		**$176,672,310.00**					**$1,525,017**	**$3,357,113**	**$5,597,278**	**$232,475**	**$10,711,883**
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 2019**	**2019 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2019 Impact (12 months)**
PSE&G	$ 466,439.83	9,978.3	$ 46.75	$ 5,597,278
JCP&L	$ 279,759.45	5,976.5	$ 46.81	$ 3,357,113
ACE	$ 127,084.72	2,591.3	$ 49.04	$ 1,525,017
RE	$ 19,372.90	414.8	$ 46.70	$ 232,475
Total Impact on NJ Zones	**$ 892,656.89**	**18,960.9**		**$10,711,883**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Attachment 6d PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019
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	**PJM Upgrade ID**		**Jan - Dec 2019 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share[1]**	**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*								
Amos-Bedington 765 kV Circuit (AEP)	b0490 &b 0491	$	1,089,444.00	1.66%	3.74%	6.26%	0.26%	$18,085	$40,745	$68,199	$2,833	$129,862
Amos-Bedington 765 kV Circuit (AEP)	b0490 & b0491	$	1,089,444.00	5.01%	11.64%	15.86%	0.59%	$54,581	$126,811	$172,786	$6,428	$360,606
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	786,866.50	1.66%	3.74%	6.26%	0.26%	$13,062	$29,429	$49,258	$2,046	$93,794
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	786,866.50	5.01%	11.64%	15.86%	0.59%	$39,422	$91,591	$124,797	$4,643	$260,453
Totals		**$**	**3,752,621.00**					**$125,150**	**$288,577**	**$415,040**	**$15,949**	**$844,715**
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 2019**	**2019 Trans. Peak Load[2]**	**Rate in $/MW-mo.[1]**	**2019 Impact (12 months)**	
PSE&G	$	34,586.66	9,978.3	$3.47	$	415,040
JCP&L	$	24,048.05	5,976.5	$4.02	$	288,577
ACE	$	10,429.16	2,591.3	$4.02	$	125,150
RE	$	1,329.05	414.8	$3.20	$	15,949
Total Impact on NJ Zones	**$**	**70,392.92**	**18,960.9**		**$**	**844,715**
Notes on calculations >>>				= (k) / (l)	= (k) *12	

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2019
2) Data on PJM website

Attachment 6e - Transmission Enhancement Charges for January 2019 - December 2019
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	**PJM Upgrade ID**	**Jan-Dec 2019 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*								
Install 230kV series reactor and 2-100MVAR PLC switched capacitors at Hunterstown	b0215	$ 1,521,328.00	6.75%	16.96%	22.82%	0.34%	$102,690	$258,017	$347,167	$5,173	$713,046
Replace wave trap at Kestone 500kV Sub	b0284.3	$ (5,787.00)	1.66%	3.74%	6.26%	0.26%	-$96	-$216	-$362	-$15	-$690
Install 100 MVAR Cap Banks at Jack's Mountain 500 kV Sub	b0369	$ (283,576.00)	1.66%	3.74%	6.26%	0.26%	-$4,707	-$10,606	-$17,752	-$737	-$33,802
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549	$ 201,467.00	1.66%	3.74%	6.26%	0.26%	$3,344	$7,535	$12,612	$524	$24,015
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549_dfax	$ 201,467.00	5.39%	17.99%	22.05%	0.89%	$10,859	$36,244	$44,423	$1,793	$93,320
Install 25 MVAR capacitor at Saxton 115 kV Sub	b0551	$ 165,244.00	8.64%	18.30%	26.32%	0.98%	$14,277	$30,240	$43,492	$1,619	$89,628
Install 50 MVAR capacitor at Altoona 230 kV Sub	b0552	$ 134,126.00	8.64%	18.30%	26.32%	0.98%	$11,588	$24,545	$35,302	$1,314	$72,750
Install 50 MVAR capacitor at Raystoon 230 kV Sub	b0553	$ 116,815.00	8.64%	18.30%	26.32%	0.98%	$10,093	$21,377	$30,746	$1,145	$63,360
Install 75 MVAR capacitor at East Towanda 230 kV Sub	b0557	$ 273,534.00	8.64%	18.30%	26.32%	0.98%	$23,633	$50,057	$71,994	$2,681	$148,365
Relocate the Erie South 345 kV Line Terminal	b1993	$ 1,396,767.00	0.00%	5.19%	12.21%	0.48%	$0	$72,492	$170,545	$6,704	$249,742
Conver Lewis Run-Farmers Valley to 230kV using 1033.5 Conductor	b1994	$ 8,661,798.00	0.00%	8.72%	13.67%	0.54%	$0	$755,309	$1,184,068	$46,774	$1,986,150
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1	$ 313,679.00	1.66%	3.74%	6.26%	0.26%	$5,207	$11,732	$19,636	$816	$37,391
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1_dfax	$ 313,679.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
							$176,888	**$1,256,725**	**$1,941,872**	**$67,790**	**$3,443,275**
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 2019**	**2019TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2019 Impact (12 months)**
PSE&G	$ 161,822.63	9,978.3	$ 16.22	$ 1,941,872
JCP&L	$ 104,727.08	5,976.5	$ 17.52	$ 1,256,725
ACE	$ 14,740.70	2,591.3	$ 5.69	$ 176,888
RE	$ 5,649.17	414.8	$ 13.62	$ 67,790
Total Impact on NJ Zones	**$ 286,939.59**			**$ 3,443,275**
Notes on calculations >>>			= (k) * (l)	= (k) *12

Notes:

1) 2019 allocation share percentages are from PJM OATT

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019
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	**PJM Upgrade ID**		**Jan - Dec 2019 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*								
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$	356,456	1.66%	3.74%	6.26%	0.26%	$5,917	$13,331	$22,314	$927	$42,490
New 765 KV circuit breakers at Hanging Rock Sub	b0504_dfax	$	356,456	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rockport Reactor Bank	b1465.2	$	859,610	1.66%	3.74%	6.26%	0.26%	$14,270	$32,149	$53,812	$2,235	$102,466
Rockport Reactor Bank	b1465.2_dfax	$	859,610	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Transpose Rockport- Sullivan 765KV line	b1465.3	$	1,128,362	1.66%	3.74%	6.26%	0.26%	$18,731	$42,201	$70,635	$2,934	$134,501
Transpose Rockport- Sullivan 765KV line	b1465.3_dfax	$	1,128,362	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Switching changes Sullivan 765KV station	b1465.4	$	(254,930)	1.66%	3.74%	6.26%	0.26%	-$4,232	-$9,534	-$15,959	-$663	-$30,388
Switching changes Sullivan 765KV station	b1465.4_dfax	$	(254,930)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sullivan Inst Baker 765kV Trnsf.	b1465.5	$	1,170,144	1.66%	3.74%	6.26%	0.26%	-$4,232	-$9,534	-$15,959	-$663	-$30,388
Sullivan Inst Baker 765kV Trnsf.	b1465.5_dfax	$	1,170,144	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
765kV circuit breaker at Wyoming station	b1661	$	(23,990)	1.66%	3.74%	6.26%	0.26%	-$398	-$897	-$1,502	-$62	-$2,860
765kV circuit breaker at Wyoming station	b1661_dfax	$	(23,990)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Term Tsfmr #2 @ SW Lima - new bay position	b1957	$	1,485,447	0.00%	0.00%	4.54%	0.18%	$0	$0	$67,439	$2,674	$70,113
Reconductor/Rebuild Sporn-Waterford-Muskingham River 345 kV Line	b2017	$	10,956,252	0.00%	1.39%	2.00%	0.08%	$0	$152,292	$219,125	$8,765	$380,182
Add four 765 kV Breakers at Kammar	b1962	$	1,353,398	1.66%	3.74%	6.26%	0.26%	$22,466	$50,617	$84,723	$3,519	$161,325
Add four 765 kV Breakers at Kammar	b1962_dfax	$	1,353,398	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Ft. Wayne Relocate	b1659.14	$	3,806,322	1.66%	3.74%	6.26%	0.26%	$63,185	$142,356	$238,276	$9,896	$453,714
Ft. Wayne Relocate	b1659.14_dfax	$	3,806,322	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sorenson 765/500kV Transformer	b1659	$	7,367,209	0.00%	0.00%	0.92%	0.04%	$0	$0	$67,778	$2,947	$70,725
Sorenson Work 765kV	b1659.13	$	2,543,231	1.66%	3.74%	6.26%	0.26%	$42,218	$95,117	$159,206	$6,612	$303,153
Sorenson Work 765kV	b1659.13_dfax	$	2,543,231	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Baker Station 765/500kV Transformer	b1495	$	4,322,480	0.41%	0.90%	1.48%	0.06%	$17,722	$38,902	$63,973	$2,593	$123,191
Cloverdale 765/500kV Transformer	b1660	$	(4,403,544)	1.66%	3.74%	6.26%	0.26%	($73,099)	($164,693)	($275,662)	($11,449)	($524,902)
Cloverdale 765/500kV Transformer	b1660_dfax	$	(4,403,544)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Cloverdale 500kV Station	b1660.1	$	2,108,878	1.66%	3.74%	6.26%	0.26%	$35,007	$78,872	$132,016	$5,483	$251,378
Cloverdale 500kV Station	b1660.1_dfax	$	2,108,878	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Jacksons-Ferry 765kV Breakers	b1663.2	$	319,922	1.66%	3.74%	6.26%	0.26%	$5,311	$11,965	$20,027	$832	$38,135
Jacksons-Ferry 765kV Breakers	b1663.2_dfax	$	319,922	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Reconductor Cloverdale-Lexington 500kV	b1797.1	$	9,517,861	1.66%	3.74%	6.26%	0.26%	$157,996	$355,968	$595,818	$24,746	$1,134,529
Reconductor West Bellaire	b1970	$	(2,693,009)	0.00%	1.68%	2.88%	0.11%	$0	-$45,243	-$77,559	-$2,962	-$125,764

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for January 2019 - December 2019
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	**PJM Upgrade ID**	**Jan - Dec 2019 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*								
Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station	b1465.1	$ 4,521,337	0.71%	1.58%	2.63%	0.10%	$32,101	$71,437	$118,911	$4,521	$226,971
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230	$ 2,387,016	1.66%	3.74%	6.26%	0.26%	$39,624	$89,274	$149,427	$6,206	$284,532
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423	$ 3,440,312	1.66%	3.74%	6.26%	0.26%	$57,109	$128,668	$215,364	$8,945	$410,085
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1	$ 8,376,163	1.66%	3.74%	6.26%	0.26%	$139,044	$313,268	$524,348	$21,778	$998,439
Install 300 MVAR shunt line reactor	b2687.2	$ 2,419,038	1.66%	3.74%	6.26%	0.26%	$40,156	$90,472	$151,432	$6,289	$288,349
Totals							**$608,898**	**$1,476,990**	**$2,567,984**	**$106,104**	**$4,759,976**
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 2019**	**2019TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2019 Impact (12 months)**
PSE&G	$ 213,998.68	9,978.3	$ 21.45	$ 2,567,984
JCP&L	$ 123,082.50	5,976.5	$ 20.59	$ 1,476,990
ACE	$ 50,741.50	2,591.3	$ 19.58	$ 608,898
RE	$ 8,842.00	414.8	$ 21.32	$ 106,104
Total Impact on NJ Zones	**$ 396,664.68**			**$ 4,759,976**
Notes on calculations >>>			= (k) * (l)	= (k) *12

Notes:
1) 2019 allocation share percentages are from PJM OATT

Attachment 7 – Cost Allocations

Attachment 7a – Responsible Customer Shares for PSE&G Schedule 12 Projects

Source – PJM OATT

Attachment 7b – Responsible Customer Shares for JCP&L Schedule 12 Projects

Source – PJM OATT

Attachment 7c – Responsible Customer Shares for VEPCo Schedule 12 Projects

Source – PJM OATT

Attachment 7d – Responsible Customer Shares for PATH Schedule 12 Projects

Source – PJM OATT

Attachment 7e – Responsible Customer Shares for MAIT Schedule 12 Projects

Source – PJM OATT

Attachment 7f – Responsible Customer Shares for AEP Schedule 12 Projects

Source – PJM OATT

Attachment 7a – Responsible Customer Shares for PSE&G Schedule 12 Projects

Source – PJM 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%)

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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		**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 (5.32%) / JCPL (33.44%) / NEPTUNE (5.35%) / PSEG (53.73%) / RE (2.16%)
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%)

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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		**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 (5.32%) / JCPL (33.44%) / NEPTUNE (5.35%) / PSEG (53.73%) / RE (2.16%)
b0358	Reconductor the PSEG portion of Buckingham – Pleasant Valley 230 kV, replace wave trap and metering transformer		PSEG (100%)

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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		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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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

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		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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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		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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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		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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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		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0489.10	Replace Roseland 230 kV breaker '21H'		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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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'		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0489.12	Replace Roseland 230 kV breaker '12H'		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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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'		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0489.14	Replace Roseland 230 kV breaker '41H'		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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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'		**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: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0498	Loop the 5021 circuit into 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 (9.56%) / JCPL (26.03%) / NEPTUNE (3.02%) / PECO (18.39%) / PSEG (41.34%) / RE (1.66%)

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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%)

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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		**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%)
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%)

*Neptune Regional Transmission System, LLC

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’		**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%)
b1411	Replace Salem 500 kV breaker ‘12X’		**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%)

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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’		**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%)
b1413	Replace Salem 500 kV breaker ‘21X’		**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%)

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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’		**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%)
b1415	Replace Salem 500 kV breaker ‘32X’		**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%)

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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%)

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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%)

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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*%)

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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%)

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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%)

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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%)

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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%)

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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%)

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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%)

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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%)

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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%)

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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%)

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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%)

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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%)
b2933	Third Source for Springfield Rd. and Stanley Terrace Stations		PSEG (100%)
b2933.1	Construct a 230/69 kV station at Springfield		PSEG (100%)
b2933.2	Construct a 230/69 kV station at Stanley Terrace		PSEG (100%)
b2933.3	Construct a 69 kV network between Front Street, Springfield and Stanley Terrace		PSEG (100%)
b2934	Build a new 69 kV line between Hasbrouck Heights and Carlstadt		PSEG (100%)
b2935	Third Supply for Runnemede 69 kV and Woodbury 69 kV		PSEG (100%)
b2935.1	Build a new 230/69 kV switching substation at Hilltop utilizing the PSE&G property and the K-2237 230 kV line		PSEG (100%)
b2935.2	Build a new line between Hilltop and Woodbury 69 kV providing the 3rd supply		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2935.3	Convert Runnemede's straight bus to a ring bus and construct a 69 kV line from Hilltop to Runnemede 69 kV		PSEG (100%)
b2955	*Wreck and rebuild the VFT – Warinanco – Aldene 230 kV circuit with paired conductor*		*JCPL (93.78%) / NEPTUNE* (6.22%)*
b2956	*Replace existing cable on Cedar Grove - Jackson Rd. with 5000kcmil XLPE cable*		*JCPL (0.05%) / NEPTUNE* (0.01%) / PSEG (96.07%) / RE (3.87%)*
b2982	Construct a 230/69 kV station at Hillsdale Substation and tie to Paramus and Dumont at 69 kV		PSEG (100%)
b2982.1	Install a 69 kV ring bus and one (1) 230/69 kV transformer at Hillsdale		PSEG (100%)
b2982.2	Construct a 69 kV network between Paramus, Dumont, and Hillsdale Substation using existing 69 kV circuits		PSEG (100%)
b2983	Convert Kuller Road to a 69/13 kV station		PSEG (100%)
b2983.1	Install 69 kV ring bus and two (2) 69/13 kV transformers at Kuller Road		PSEG (100%)
b2983.2	Construct a 69 kV network between Kuller Road, Passaic, Paterson, and Harvey (new Clifton area switching station)		PSEG (100%)
b2986	Replace the existing Roseland – Branchburg – Pleasant Valley 230 kV corridor with new structures		PSEG (100%)

Attachment 7b – Responsible Customer Shares for JCP&L Schedule 12 Projects
Source – PJM OATT

SCHEDULE 12 – APPENDIX

(4) Jersey Central Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0123	Add 180 MVAR of distributed capacitors. 65 MVAR in northern JCPL and 115 MVAR in southern JCPL		JCPL (100%)
b0124.1	Add a 72 MVAR capacitor at Kittatinny 230 kV		JCPL (100%)
b0124.2	Add a 130 MVAR capacitor at Manitou 230 kV		JCPL (100%)
b0132	Reconductor Portland – Kittatinny 230 kV with 1590 ACSS		JCPL (100%)
b0132.1	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Kittatinny bus		JCPL (100%)
b0132.2	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Portland bus		JCPL (100%)
b0173	Replace a line trap at Newton 230kV substation for the Kittatinny-Newton 230kV circuit		JCPL (100%)
b0174	Upgrade the Portland – Greystone 230kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $1,442,372 2018: $1,273,748 2019: $1,235,637	JCPL (35.40%) / Neptune* (5.67%) / PSEG (54.37%) RE (2.94%) / ECP** (1.62%)
b0199	Greystone 230kV substation: Change Tap of limiting CT and replace breaker on the Greystone Whippany (Q1031) 230kV line		JCPL (100%)
b0200	Greystone 230kV substation: Change Tap of limiting CT on the West Wharton Greystone (E1045) 230kV line		JCPL (100%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0202	Kittatinny 230kV substation: Replace line trap on Kittatinny Pohatcong (L2012) 230kV line; Pohatcong 230kV substation: Change Tap of limiting CT on Kittatinny Pohatcong (L2012) 230kV line		JCPL (100%)
b0203	Smithburg 230kV Substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line; East Windsor 230kV substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line		JCPL (100%)
b0204	Install 72Mvar capacitor at Cookstown 230kV substation		JCPL (100%)
b0267	Reconductor JCPL 2 mile portion of Kittatinny – Newton 230 kV line		JCPL (100%)
b0268	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $734,194 2018: $646,180 2019: $628,066	JCPL (61.77%) / Neptune* (3%) / PSEG (32.73%) / RE (1.45%) / ECP** (1.05%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0279.1	Install 100 MVAR capacitor at Glen Gardner substation		JCPL (100%)
b0279.2	Install MVAR capacitor at Kittatinny 230 kV substation		JCPL (100%)
b0279.3	Install 17.6 MVAR capacitor at Freneau 34.5 kV substation		JCPL (100%)
b0279.4	Install 6.6 MVAR capacitor at Waretown #1 bank 34.5 kV substation		JCPL (100%)
b0279.5	Install 10.8 MVAR capacitor at Spottswood #2 bank .4.5 kV substation		JCPL (100%)
b0279.6	Install 6.6 MVAR capacitor at Pequannock N bus 34.5 kV substation		JCPL (100%)
b0279.7	Install 6.6 MVAR capacitor at Haskell P bus 34.5 kV substation		JCPL (100%)
b0279.8	Install 6.6 MVAR capacitor at Pinewald #2 Bank 34.5 kV substation		JCPL (100%)
b0279.9	Install 6.6 MVAR capacitor at Matrix 34.5 kV substation		JCPL (100%)
b0279.10	Install 6.6 MVAR capacitor at Hamburg Boro Q Bus 34.5 kV substation		JCPL (100%)
b0279.11	Install 6.6 MVAR capacitor at Newburg Q Bus 34.5 kV substation		JCPL (100%)
b0286	Install 130 MVAR capacitor at Whippany 230 kV		JCPL (100%)
b0289	Install 600 MVAR Dynamic Reactive Device in the Whippany 230 kV vicinity		AEC (0.65%) / JCPL (30.37%) / Neptune* (4.96%) / PSEG (59.65%) / RE (2.66%) / ECP** (1.71%)
b0289.1	Install additional 130 MVAR capacitor at West Wharton 230 kV substation		JCPL (100%)

* Neptune Regional Transmission System, LLC

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0292	Replace a 1600A line trap at Atlantic Larrabee 230 kV substation		JCPL (100%)
b0350	Implement Operating Procedure of closing the Glendon – Gilbert 115 kV circuit		JCPL (100%)
b0356	Replace wave trap on the Portland – Greystone 230 kV		JCPL (100%)
b0361	Change tap of limiting CT at Morristown 230 kV		JCPL (100%)
b0362	Change tap setting of limiting CT at Pohatcong 230 kV		JCPL (100%)
b0363	Change tap setting of limiting CT at Windsor 230 kV		JCPL (100%)
b0364	Change tap setting of CT at Cookstown 230 kV		JCPL (100%)
b0423.1	Upgrade terminal equipment at Readington (substation conductor)		JCPL (100%)
b0520	Replace Gilbert circuit breaker 12A		JCPL (100%)
b0657	Construct Boston Road 34.5 kV stations, construct Hyson 34.5 stations, add a 7.2 MVAR capacitor at Boston Road 34.5 kV		JCPL (100%)
b0726	Add a 2nd Raritan River 230/115 kV transformer	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $950,666 2018: $846,872 2019: $827,854	AEC (2.45%) / JCPL (97.55%)
b1020	Replace wave trap at Englishtown on the Englishtown - Manalapan circuit		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1075	Replace the West Wharton - Franklin - Vermont D931 and J932 115 kV line conductors with 1590 45/7 ACSR wire between the tower structures 78 and 78-B		JCPL (100%)
b1154.1	Upgrade the Whippany 230 kV breaker 'JB'		JCPL (100%)
b1155.1	Upgrade the Red Oak 230 kV breaker 'G1047'		JCPL (100%)
b1155.2	Upgrade the Red Oak 230 kV breaker 'T1034'		JCPL (100%)
b1345	Install Martinsville 4-breaker 34.5 rink bus		JCPL (100%)
b1346	Reconductor the Franklin – Humburg (R746) 4.7 miles 34.5 kV line with 556 ACSR and build 2.7 miles 55 ACSR line extension to Sussex		JCPL (100%)
b1347	Replace 500 CU substation conductor with 795 ACSR on the Whitesville – Asbury Tap 34.5 kV (U47) line		JCPL (100%)
b1348	Upgrade the Newton – North Newton 34.5 kV (F708) line by adding a second underground 1250 CU egress cable		JCPL (100%)
b1349	Reconductor 5.2 miles of the Newton – Woodruffs Gap 34.5 kV (A703) line with 556 ACSR		JCPL (100%)
b1350	Upgrade the East Flemington – Flemington 34.5 kV (V724) line by adding second underground 1000 AL egress cable and replacing 4/0		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1351	Add 34.5 kV breaker on the Larrabee A and D bus tie		JCPL (100%)
b1352	Upgrade the Smithburg – Centerstate Tap 34.5 kV (X752) line by adding second 200 ft underground 1250 CU egress cable		JCPL (100%)
b1353	Upgrade the Larrabee – Laurelton 34.5 kV (Q43) line by adding second 700 ft underground 1250 CU egress cable		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1354	Add four 34.5 kV breakers and re-configure A/B bus at Rockaway		JCPL (100%)
b1355	Build a new section 3.3 miles 34.5 kV 556 ACSR line from Riverdale to Butler		JCPL (100%)
b1357	Build 10.2 miles new 34.5 kV line from Larrabee – Howell		JCPL (100%)
b1359	Install a Troy Hills 34.5 kV by-pass switch and reconfigure the Montville – Whippany 34.5 kV (D4) line		JCPL (100%)
b1360	Reconductor 0.7 miles of the Englishtown – Freehold Tap 34.5 kV (L12) line with 556 ACSR		JCPL (100%)
b1361	Reconductor the Oceanview – Neptune Tap 34.5 kV (D130) line with 795 ACSR		JCPL (100%)
b1362	Install a 23.8 MVAR capacitor at Wood Street 69 kV		JCPL (100%)
b1364	Upgrade South Lebanon 230/69 kV transformer #1 by replacing 69 kV substation conductor with 1590 ACSR		JCPL (100%)
b1399.1	Upgrade the Whippany 230 kV breaker ‘QJ’		JCPL (100%)
b1673	Rocktown - Install a 230/34.5 kV transformer by looping the Pleasant Valley - E Flemington 230 kV Q-2243 line (0.4 miles) through the Rocktown Substation		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1674	Build a new Englishtown - Wyckoff St 15 mile, 115 kV line and install 115/34.5 kV transformer at Wyckoff St		JCPL (100%)
b1689	Atlantic Sub - 230 kV ring bus reconfiguration. Put a “source” between the Red Bank and Oceanview “loads”		JCPL (100%)
b1690	Build a new third 230 kV line into the Red Bank 230 kV substation		JCPL (100%)
b1853	Install new 135 MVA 230/34.5 kV transformer with one 230 kV CB at Eaton Crest and create a new 34.5 kV CB straight bus to feed new radial lines to Locust Groove and Interdata/Woodbine		JCPL (100%)
b1854	Readington I737 34.5 kV Line - Parallel existing 1250 CU UG cable (440 feet)		JCPL (100%)
b1855	Oceanview Substation - Relocate the H216 breaker from the A bus to the B bus		JCPL (100%)
b1856	Madison Tp to Madison (N14) line - Upgrade limiting 250 Cu substation conductor with 795 ACSR at Madison sub		JCPL (100%)
b1857	Montville substation - Replace both the 397 ACSR and the 500 Cu substation conductor with 795 ACSR on the 34.5 kV (M117) line		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1858	Reconductor the Newton - Mohawk (Z702) 34.5 kV line with 1.9 miles of 397 ACSR		JCPL (100%)
b2003	Construct a Whippany to Montville 230 kV line (6.4 miles)		JCPL (100%)
b2015	Build a new 230 kV circuit from Larrabee to Oceanview	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $9,616,241 2018: $18,839,128 2019: $19,935,489	JCPL (35.83%) / NEPTUNE* (23.61%) / HTP (1.77%) / ECP** (1.49%) / PSEG (35.87%) / RE (1.43%)
b2147	At Deep Run, install 115 kV line breakers on the B2 and C3 115 kV lines		JCPL (100%)

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

SCHEDULE 12 – APPENDIX A

(4) Jersey Central Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2234	260 MVAR reactor at West Wharton 230 kV		JCPL (100%)
b2270	Advance Raritan River - Replace G1047E breaker at the 230kV Substation		JCPL (100%)
b2271	Advance Raritan River - Replace G1047F breaker at the 230kV Substation		JCPL (100%)
b2272	Advance Raritan River - Replace T1034E breaker at the 230kV Substation		JCPL (100%)
b2273	Advance Raritan River - Replace T1034F breaker at the 230kV Substation		JCPL (100%)
b2274	Advance Raritan River - Replace I1023E breaker at the 230kV Substation		JCPL (100%)
b2275	Advance Raritan River - Replace I1023F breaker at the 230kV Substation		JCPL (100%)
b2289	Freneau Substation - upgrade 2.5 inch pipe to bundled 1590 ACSR conductor at the K1025 230 kV Line Terminal		JCPL (100%)
b2292	Replace the Whippany 230 kV breaker B1 (CAP) with 63kA breaker		JCPL (100%)
b2357	Replace the East Windsor 230 kV breaker 'E1' with 63kA breaker		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2495	Replace transformer leads on the Glen Gardner 230/34.5 kV #1 transformer		JCPL (100%)
b2496	Replace Franklin 115/34.5 kV transformer #2 with 90 MVA transformer		JCPL (100%)
b2497	Reconductor 0.9 miles of the Captive Plastics to Morris Park 34.5 kV circuit (397ACSR) with 556 ACSR		JCPL (100%)
b2498	Extend 5.8 miles of 34.5 kV circuit from North Branch substation to Lebanon substation with 397 ACSR and install 34.5 kV breaker at Lebanon substation		JCPL (100%)
b2500	Upgrade terminal equipment at Monroe on the Englishtown to Monroe (H34) 34.5 kV circuit		JCPL (100%)
b2570	Upgrade limiting terminal facilities at Feneau, Parlin, and Williams substations		JCPL (100%)
b2571	Upgrade the limiting terminal facilities at both Jackson and North Hanover		JCPL (100%)
b2586	Upgrade the V74 34.5 kV transmission line between Allenhurst and Elberon Substations		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2633.6	Implement high speed relaying utilizing OPGW on Deans – East Windsor 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: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.6.1	Implement high speed relaying utilizing OPGW on East Windsor - New Freedom 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: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2676	Install one (1) 72 MVAR fast switched capacitor at the Englishtown 230 kV substation		JCPL (100%)
b2708	Replace the Oceanview 230/34.5 kV transformer #1		JCPL (100%)
b2709	Replace the Deep Run 230/34.5 kV transformer #1		JCPL (100%)
b2754.2	Install 5 miles of optical ground wire (OPGW) between Gilbert and Springfield 230 kV substations		JCPL (100%)
b2754.3	Install 7 miles of all-dielectric self-supporting (ADSS) fiber optic cable between Morris Park and Northwood 230 kV substations		JCPL (100%)
b2754.6	Upgrade relaying at Morris Park 230 kV		JCPL (100%)
b2754.7	Upgrade relaying at Gilbert 230 kV		JCPL (100%)

Attachment 7c – Responsible Customer Shares for VEPCo Schedule 12 Projects

Source – PJM 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		**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 (25.20%) / BGE (10.49%) / Dominion (52.48%) / PEPCO (11.83%)
b0222	Install 150 MVAR capacitor at Loudoun 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: Dominion (100%)

* 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		**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%)
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%)

* Neptune Regional Transmission System, LLC
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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)		**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%)

* Neptune Regional Transmission System, LLC

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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		**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 (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0328.4	Upgrade Loudoun 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: Dominion (100%)

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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		**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%)
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		**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 (51.45%) / DEOK (17.51%) / PEPCO (31.04%)
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		**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%)
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		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0492.7	Replace Mount Storm 500 kV breaker 55172		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.8	Replace Mount Storm 500 kV breaker H1172-2		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0492.9	Replace Mount Storm 500 kV breaker G2T550		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.10	Replace Mount Storm 500 kV breaker G2T554		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0492.11	Replace Mount Storm 500 kV breaker G1T551		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

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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		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
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		**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%)

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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		**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%)
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		**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%)

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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		**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%)
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		**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 (25.20%) / BGE (10.49%) / Dominion (52.48%) / PEPCO (11.83%)
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		**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%)
b1648	Upgrade name plate rating at Morrisville 500kV breaker ‘H2T545’ with 50kA breaker		**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%)

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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		**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%)
b1650	Replace Morrisville 500kV breaker ‘H2T569’ with 50kA breaker		**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%)
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		**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 (84.25%) / PEPCO (15.75%)
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		**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%)

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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		**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 (56.31%) / ATSI (2.31%) / Dayton (0.70%) / DEOK (1.72%) / Dominion (4.80%) / EKPC (0.60%) / PEPCO (33.56%)
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 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: Dominion (100%)

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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		**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 (0.36%) / DPL (0.07%) / Dominion (99.36%) / ME (0.07%) / PEPCO (0.14%)
b1805	Install a 250 MVAR SVC at the existing Mt. Storm 500kV 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: APS (74.10%) / PEPCO (25.90%)
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)		**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%)
b1905.2	Surry 500 kV Station Work		**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%)
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%)

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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		**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%)
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%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1908	Rebuild Lexington – Dooms 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: Dominion (100%)
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%)

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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%)

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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		**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%) / Dominion (12.86%) / DPL (2.50%) / 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 (33.33%) / Dominion (66.67%)
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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2649.1	Rebuild of 1.7 mile tap to Metcalf and Belfield DP (MEC) due to poor condition. The existing summer rating of the tap is 48 MVA and existing conductor is 4/0 ACSR on wood H-frames. The proposed new rating is 176 MVA using 636 ACSR conductor		Dominion (100%)
b2649.2	Rebuild of 4.1 mile tap to Brinks DP (MEC) due to wood poles built in 1962. The existing summer rating of the tap is 48 MVA and existing conductor is 4/0 ACSR and 393.6 ACSR on wood H-frames. The proposed new rating is 176 MVA using 636 ACSR conductor		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%)
b2800	The 7 mile section from Dozier to Thompsons Corner of line #120 will be rebuilt to current standards using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115 kV. Line is proposed to be rebuilt on single circuit steel monopole structure		Dominion (100%)
b2801	Lines #76 and #79 will be rebuilt to current standard using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115 kV. Proposed structure for rebuild is double circuit steel monopole structure		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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
b2876	Rebuild line #101 from Mackeys – Creswell 115 kV, 14 miles, with double circuit structures. Install one circuit with provisions for a second circuit. The conductor used will be at current standards with a summer emergency rating of 262 MVA at 115 kV		Dominion (100%)
b2877	Rebuild line #112 from Fudge Hollow – Lowmoor 138 kV (5.16 miles) to current standards with a summer emergency rating of 314 MVA at 138 kV		Dominion (100%)
b2899	Rebuild 230 kV line #231 to current standard with a summer emergency rating of 1046 MVA. Proposed conductor is 2-636 ACSR		Dominion (100%)
b2900	Build a new 230/115 kV switching station connecting to 230 kV network line #2014 (Earleys – Everetts). Provide a 115 kV source from the new station to serve Windsor DP		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2922	Rebuild 8 of 11 miles of 230 kV lines #211 and #228 to current standard with a summer emergency rating of 1046 MVA for rebuilt section. Proposed conductor is 2-636 ACSR		Dominion (100%)
b2928	Rebuild four structures of 500 kV line #567 from Chickahominy to Surry using galvanized steel and replace the river crossing conductor with 3-1534 ACSR. This will increase the line #567 line rating from 1954 MVA to 2600 MVA		Dominion (100%)
b2929	Rebuild 230 kV line #2144 from Winfall to Swamp (4.3 miles) to current standards with a standard conductor (bundled 636 ACSR) having a summer emergency rating of 1047 MVA at 230 kV		Dominion (100%)
b2960	*Replace fixed series capacitors on 500 kV Line #547 at Lexington and on 500 kV Line #548 at Valley*		*Dominion (100%)*
b2961	*Rebuild approximately 3 miles of Line #205 & Line #2003 from Chesterfield to Locks & Poe respectively*		*Dominion (100%)*
b2962	*Split Line #227 (Brambleton – Beaumeade 230 kV) and terminate into existing Belmont substation*		*Dominion (100%)*
b2963	*Reconductor the Woodbridge to Occoquan 230 kV line segment of Line #2001 with 1047 MVA conductor and replace line terminal equipment at Possum Point, Woodbridge, and Occoquan*		*Dominion (100%)*

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2978	Install 2-125 MVAR STATCOMs at Rawlings and 1-125 MVAR STATCOM at Clover 500 kV substations		**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%) / Dominion (12.86%) / DPL (2.50%) / 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%)
b2980	Rebuild 115 kV Line #43 between Staunton and Harrisonburg (22.8 miles) to current standards with a summer emergency rating of 261 MVA at 115 kV		Dominion (100%)
b2981	Rebuild 115 kV Line #29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV)		Dominion (100%)

*Neptune Regional Transmission System, LLC

Attachment 7d – Responsible Customer Shares for PATH Schedule 12 Projects

Source – PJM 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	**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

*Neptune Regional Transmission System, LLC

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	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
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)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 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: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0560	Install 250 MVAR capacitor at Kemptown 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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

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	**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

Attachment 7e – Responsible Customer Shares for MAIT Schedule 12 Projects
Source – PJM OATT

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0215	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown		AEC (*6.75*%) / 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		**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 (0.01%) / DPL (55.56%) / ME (44.42%) / PSEG (0.01%)
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

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

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.1	Build 500 kV substation in PENELEC – Tap the Keystone – Juniata and Conemaugh – Juniata 500 kV, connect the circuits with a breaker and half scheme, and install new 400 MVAR capacitor		AEC (1.66%) / 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		**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 (5.35%) / BGE (19.46%) / DL (0.25%) / JCPL (19.57%) / ME (6.75%) / NEPTUNE (2.17%) / PECO (20.81%) / PSEG (24.65%) / RE (0.99%)
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		**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 (5.39%) / BGE (23.28%) / JCPL (17.99%) / ME (7.64%) / NEPTUNE (1.99%) / PECO (20.77%) / PSEG (22.05%) / RE (0.89%)
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%)
b2950	Upgrade limiting 115 kV switches on the 115 kV side of the 230/115 kV Northwood substation and adjust setting on limiting ZR relay		ME (100%)

SCHEDULE 12 – APPENDIX A

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

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

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

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

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2743.2	Tie in new Rice substation to Conemaugh – Hunterstown 500 kV		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2743.3	Upgrade terminal equipment at Conemaugh 500 kV on the Conemaugh – Hunterstown 500 kV circuit		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2748	Install two 28 MVAR capacitors at Tiffany 115 kV substation		PENELEC (100%)
b2767	Construct a new 345 kV breaker string with three (3) 345 kV breakers at Homer City and move the North autotransformer connection to this new breaker string		PENELEC (100%)
b2803	Reconductor 3.7 miles of the Bethlehem – Leretto 46 kV circuit and replace terminal equipment at Summit 46 kV		PENELEC (100%)
b2804	Install a new relay and replace 4/0 CU bus conductor at Huntingdon 46 kV station, on the Huntingdon – C tap 46 kV circuit		PENELEC (100%)
b2805	Install a new relay and replace 4/0 CU & 250 CU substation conductor at Hollidaysburg 46 kV station, on the Hollidaysburg – HCR Tap 46 kV circuit		PENELEC (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2806	Install a new relay and replace meter at the Raystown 46 kV substation, on the Raystown – Smithfield 46 kV circuit		PENELEC (100%)
b2807	Replace the CHPV and CRS relay, and adjust the IAC overcurrent relay trip setting; or replace the relay at Eldorado 46 kV substation, on the Eldorado – Gallitzin 46 kV circuit		PENELEC (100%)
b2808	Adjust the JBC overcurrent relay trip setting at Raystown 46 kV, and replace relay and 4/0 CU bus conductor at Huntingdon 46 kV substations, on the Raystown – Huntingdon 46 kV circuit		PENELEC (100%)
b2865	Replace Seward 115 kV breaker "Jackson Road" with 63kA breaker		PENELEC (100%)
b2866	Replace Seward 115 kV breaker "Conemaugh N." with 63kA breaker		PENELEC (100%)
b2867	Replace Seward 115 kV breaker "Conemaugh S." with 63kA breaker		PENELEC (100%)
b2868	Replace Seward 115 kV breaker "No.8 Xfmr" with 63kA breaker		PENELEC (100%)
b2944	Install two 345 kV 80 MVAR shunt reactors at Mainesburg station		PENELEC (100%)

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

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2951	*Seward, Blairsville East, Shelocta work*		*PENELEC (100%)*
b2951.1	*Upgrade Florence 115 kV line terminal equipment at Seward SS*		*PENELEC (100%)*
b2951.2	*Replace Blairsville East / Seward 115 kV line tuner, coax, line relaying and carrier set at Shelocta SS*		*PENELEC (100%)*
b2951.3	*Replace Seward / Shelocta 115 kV line CVT, tuner, coax, and line relaying at Blairsville East SS*		*PENELEC (100%)*
b2952	*Replace the North Meshoppen #3 230/115 kV transformer eliminating the old reactor and installing two breakers to complete a 230 kV ring bus at North Meshoppen*		*PENELEC (100%)*
b2953	*Replace the Keystone 500 kV breaker "NO. 14 Cabot" with 50kA breaker*		*PENELEC (100%)*
b2954	*Replace the Keystone 500 kV breaker "NO. 16 Cabot" with 50kA breaker*		*PENELEC (100%)*
b2984	Reconfigure the bus at Glory and install a 50.4 MVAR 115 kV capacitor		PENELEC (100%)

Attachment 7f – Responsible Customer Shares for AEP Schedule 12 Projects
Source – PJM 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	**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

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’		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0490.3	Replace Amos 138 kV breaker ‘B1’		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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'		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0490.5	Replace Amos 138 kV breaker 'C1'		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.6	Replace Amos 138 kV breaker ‘D’		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0490.7	Replace Amos 138 kV breaker ‘D2’		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.8	Replace Amos 138 kV breaker ‘E’		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0490.9	Replace Amos 138 kV breaker ‘E2’		**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 (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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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		**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%)
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%)

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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%)

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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%)

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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		**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)
b1465.3	Transpose the Rockport – Sullivan 765 kV line and the Rockport – Jefferson 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%)
b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		**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%)
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		**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 (73.42%) / Dayton (11.78%) / DEOK (14.80%)
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville 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 (63.21%) / ATSI (18.99%) / ComEd (3.32%) / Dayton (8.73%) / DL (5.41%) / EKPC (0.34%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1660	Install a 765/500 kV transformer at Cloverdale		**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 (98.28%) / DEOK (0.45%) / Dominion (1.11%) / EKPC (0.16%)
b1661	Install a 765 kV circuit breaker at Wyoming 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)
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		**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%)
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		**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%)
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%)

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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.

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)

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%)

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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%)

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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%)

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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%)

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

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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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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%)

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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%)

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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%)

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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%)
b2761.3	*Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating)*		*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%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)
b2787	Reconductor 0.53 miles (14 spans) of the Kaiser Jct. - Air Force Jct. Sw section of the Kaiser - Heath 69 kV circuit/line with 336 ACSR to match the rest of the circuit (73 MVA rating, 78% loading)		AEP (100%)
b2788	Install a new 3-way 69 kV line switch to provide service to AEP's Barnesville distribution station. Remove a portion of the #1 copper T-Line from the 69 kV through-path		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2789	Rebuild the Brues - Glendale Heights 69 kV line section (5 miles) with 795 ACSR (128 MVA rating, 43% loading)		AEP (100%)
b2790	Install a 3 MVAR, 34.5 kV cap bank at Caldwell substation		AEP (100%)
b2791	Rebuild Tiffin – Howard, new transformer at Chatfield		AEP (100%)
b2791.1	Rebuild portions of the East Tiffin - Howard 69 kV line from East Tiffin to West Rockaway Switch (0.8 miles) using 795 ACSR Drake conductor (129 MVA rating, 50% loading)		AEP (100%)
b2791.2	Rebuild Tiffin - Howard 69 kV line from St. Stephen's Switch to Hinesville (14.7 miles) using 795 ACSR Drake conductor (90 MVA rating, non-conductor limited, 38% loading)		AEP (100%)
b2791.3	New 138/69 kV transformer with 138/69 kV protection at Chatfield		AEP (100%)
b2791.4	New 138/69 kV protection at existing Chatfield transformer		AEP (100%)
b2792	Replace the Elliott transformer with a 130 MVA unit, reconductor 0.42 miles of the Elliott – Ohio University 69 kV line with 556 ACSR to match the rest of the line conductor (102 MVA rating, 73% loading) and rebuild 4 miles of the Clark Street – Strouds R		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2793	Energize the spare Fremont Center 138/69 kV 130 MVA transformer #3. Reduces overloaded facilities to 46% loading		AEP (100%)
b2794	Construct new 138/69/34 kV station and 1-34 kV circuit (designed for 69 kV) from new station to Decliff station, approximately 4 miles, with 556 ACSR conductor (51 MVA rating)		AEP (100%)
b2795	Install a 34.5 kV 4.8 MVAR capacitor bank at Killbuck 34.5 kV station		AEP (100%)
b2796	Rebuild the Malvern - Oneida Switch 69 kV line section with 795 ACSR (1.8 miles, 125 MVA rating, 55% loading)		AEP (100%)
b2797	Rebuild the Ohio Central - Conesville 69 kV line section (11.8 miles) with 795 ACSR conductor (128 MVA rating, 57% loading). Replace the 50 MVA Ohio Central 138/69 kV XFMR with a 90 MVA unit		AEP (100%)
b2798	Install a 14.4 MVAR capacitor bank at West Hicksville station. Replace ground switch/MOAB at West Hicksville with a circuit switcher		AEP (100%)
b2799	Rebuild Valley - Almena, Almena - Hartford, Riverside - South Haven 69 kV lines. New line exit at Valley Station. New transformers at Almena and Hartford		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2799.1	Rebuild 12 miles of Valley – Almena 69 kV line as a double circuit 138/69 kV line using 795 ACSR conductor (360 MVA rating) to introduce a new 138 kV source into the 69 kV load pocket around Almena station		AEP (100%)
b2799.2	Rebuild 3.2 miles of Almena to Hartford 69 kV line using 795 ACSR conductor (90 MVA rating)		AEP (100%)
b2799.3	Rebuild 3.8 miles of Riverside – South Haven 69 kV line using 795 ACSR conductor (90 MVA rating)		AEP (100%)
b2799.4	At Valley station, add new 138 kV line exit with a 3000 A 40 kA breaker for the new 138 kV line to Almena and replace CB D with a 3000 A 40 kA breaker		AEP (100%)
b2799.5	At Almena station, install a 90 MVA 138/69 kV transformer with low side 3000 A 40 kA breaker and establish a new 138 kV line exit towards Valley		AEP (100%)
b2799.6	At Hartford station, install a second 90 MVA 138/69 kV transformer with a circuit switcher and 3000 A 40 kA low side breaker		AEP (100%)

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

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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%)
b2872	Replace the South Canton 138 kV breaker ‘K2’ with a 80 kA breaker		AEP (100%)
b2873	Replace the South Canton 138 kV breaker “M” with a 80 kA breaker		AEP (100%)
b2874	Replace the South Canton 138 kV breaker “M2” with a 80 kA breaker		AEP (100%)
b2878	Upgrade the Clifty Creek 345 kV risers		AEP (100%)
b2880	Rebuild approximately 4.77 miles of the Cannonsburg – South Neal 69 kV line section utilizing 795 ACSR conductor (90 MVA rating)		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2881	Rebuild ~1.7 miles of the Dunn Hollow – London 46 kV line section utilizing 795 26/7 ACSR conductor (58 MVA rating, non-conductor limited)		AEP (100%)
b2882	Rebuild Reusens - Peakland Switch 69 kV line. Replace Peakland Switch		AEP (100%)
b2882.1	Rebuild the Reusens - Peakland Switch 69 kV line (approximately 0.8 miles) utilizing 795 ACSR conductor (86 MVA rating, non-conductor limited)		AEP (100%)
b2882.2	Replace existing Peakland S.S with new 3 way switch phase over phase structure		AEP (100%)
b2883	Rebuild the Craneco – Pardee – Three Forks – Skin Fork 46 kV line section (approximately 7.2 miles) utilizing 795 26/7 ACSR conductor (108 MVA rating)		AEP (100%)
b2884	Install a second transformer at Nagel station, comprised of 3 single phase 250 MVA 500/138 kV transformers. Presently, TVA operates their end of the Boone Dam – Holston 138 kV interconnection as normally open preemptively for the loss of the existing Nagel		AEP (100%)
b2885	New delivery point for City of Jackson		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2885.1	Install a new Ironman Switch to serve a new delivery point requested by the City of Jackson for a load increase request		AEP (100%)
b2885.2	Install a new 138/69 kV station (Rhodes) to serve as a third source to the area to help relieve overloads caused by the customer load increase		AEP (100%)
b2885.3	Replace Coalton Switch with a new three breaker ring bus (Heppner)		AEP (100%)
b2886	Install 90 MVA 138/69 kV transformer, new transformer high and low side 3000 A 40 kA CBs, and a 138 kV 40 kA bus tie breaker at West End Fostoria		AEP (100%)
b2887	Add 2-138 kV CB's and relocate 2-138 kV circuit exits to different bays at Morse Road. Eliminate 3 terminal line by terminating Genoa - Morse circuit at Morse Road		AEP (100%)
b2888	Retire Poston substation. Install new Lemaster substation		AEP (100%)
b2888.1	Remove and retire the Poston 138 kV station		AEP (100%)
b2888.2	Install a new greenfield station, Lemaster 138 kV Station, in the clear		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2888.3	Relocate the Trimble 69 kV AEP Ohio radial delivery point to 138 kV, to be served off of the Poston – Strouds Run – Crooksville 138 kV circuit via a new three-way switch. Retire the Poston - Trimble 69 kV line		AEP (100%)
b2889	Expand Cliffview station		AEP (100%)
b2889.1	Cliffview Station: Establish 138 kV bus. Install two 138/69 kV XFRs (130 MVA), six 138 kV CBs (40 kA 3000 A) and four 69 kV CBs (40 kA 3000 A)		AEP (100%)
b2889.2	Byllesby – Wythe 69 kV: Retire all 13.77 miles (1/0 CU) of this circuit (~4 miles currently in national forest)		AEP (100%)
b2889.3	Galax – Wythe 69 kV: Retire 13.53 miles (1/0 CU section) of line from Lee Highway down to Byllesby. This section is currently double circuited with Byllesby – Wythe 69 kV. Terminate the southern 3/0 ACSR section into the newly opened position at Byllesby		AEP (100%)
b2889.4	Cliffview Line: Tap the existing Pipers Gap – Jubal Early 138 kV line section. Construct double circuit in/out (~2 miles) to newly established 138 kV bus, utilizing 795 26/7 ACSR conductor		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2890.1	Rebuild 23.55 miles of the East Cambridge – Smyrna 34.5 kV circuit with 795 ACSR conductor (128 MVA rating) and convert to 69 kV		AEP (100%)
b2890.2	East Cambridge: Install a 2000 A 69 kV 40 kA circuit breaker for the East Cambridge – Smyrna 69 kV circuit		AEP (100%)
b2890.3	Old Washington: Install 69 kV 2000 A two way phase over phase switch		AEP (100%)
b2890.4	Install 69 kV 2000 A two way phase over phase switch		AEP (100%)
b2891	Rebuild the Midland Switch to East Findlay 34.5 kV line (3.31 miles) with 795 ACSR (63 MVA rating) to match other conductor in the area		AEP (100%)
b2892	Install new 138/12 kV transformer with high side circuit switcher at Leon and a new 138 kV line exit towards Ripley. Establish 138 kV at the Ripley station with a new 138/69 kV 130 MVA transformer and move the distribution load to 138 kV service		AEP (100%)
b2936.1	Rebuild approximately 6.7 miles of 69 kV line between Mottville and Pigeon River using 795 ACSR conductor (129 MVA rating). New construction will be designed to 138 kV standards but operated at 69 kV		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)
b2936.2	Pigeon River Station: Replace existing MOAB Sw. ‘W’ with a new 69 kV 3000 A 40 kA breaker, and upgrade existing relays towards HMD station. Replace CB H with a 3000 A 40 kA breaker		AEP (100%)
b2937	Replace the existing 636 ACSR 138 kV bus at Fletchers Ridge with a larger 954 ACSR conductor		AEP (100%)
b2938	Perform a sag mitigations on the Broadford – Wolf Hills 138 kV circuit to allow the line to operate to a higher maximum temperature		AEP (100%)
b2958.1	*Cut George Washington – Tidd 138 kV circuit into Sand Hill and reconfigure Brues & Warton Hill line entrances*		*AEP (100%)*
b2958.2	*Add 2 138 kV 3000 A 40 kA breakers, disconnect switches, and update relaying at Sand Hill station*		*AEP (100%)*
b2968	*Upgrade existing 345 kV terminal equipment at Tanner Creek station*		*AEP (100%)*
b2969	*Replace terminal equipment on Maddox Creek - East Lima 345 kV circuit*		*AEP (100%)*
b2976	*Upgrade terminal equipment at Tanners Creek 345 kV station. Upgrade 345 kV bus and risers at Tanners Creek for the Dearborn circuit*		*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)
b2988	Replace the Twin Branch 345 kV breaker "JM" with 63 kA breaker and associated substation works including switches, bus leads, control cable and new DICM		AEP (100%)

Attachment 8

MAIT Formula Rate for January 1, 2019 to December 31, 2019

Attachment 8

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

Line No.	(1)	(2) **Reference**	(3) **Transmission**	(4) **Allocator**
1	Gross Transmission Plant - Total	Attach. H-28A, p. 2, line 2, col. 5 (Note A)	$ 1,579,600,454	
2	Net Transmission Plant - Total	Attach. H-28A, p. 2, line 14, col. 5 (Note B)	$ 1,240,678,415	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-28A, p. 3, line 15, col. 5	$ 66,228,405	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	4.192731%	4.192731%
	GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE			
5	Total G, I, & C depreciation expense	Attach. H-28A, p. 3, lines 17 & 18, col. 5	$ 1,014,344	
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)	0.064215%	0.064215%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-28A, p. 3, line 28, col. 5	$ 520,200	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)	0.032932%	0.032932%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		**4.289879%**
	INCOME TAXES			
10	Total Income Taxes	Attach. H-28A, p. 3, line 39, col. 5	$ 24,740,904	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)	1.994143%	1.994143%
	RETURN			
12	Return on Rate Base	Attach. H-28A, p. 3, line 40, col. 5	$ 79,678,780	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)	6.422194%	6.422194%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**8.416338%**

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

(5) Line No.	(6)	(7) **Reference**	(8) **Transmission**	(9) **Allocator**
	INCOME TAXES			
10b	Total Income Taxes	Attachment 2, line 33	$ 24,740,904	
11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)	1.994143%	1.994143%
	RETURN			
12b	Return on Rate Base	Attachment 2, line 22	$ 79,678,780	
13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)	6.422194%	6.422194%
14b	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		**8.416338%**
15	**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		**0.00000%**

Attachment 8

Transmission Enhancement Charge (TEC) Worksheet

To be completed in conjunction with Attachment H-28A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Project Name	RTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	Additional Incentive Annual Allocation Factor for Return (Note F)	Total Annual Revenue Requirement	True-up Adjustment	Net Revenue Requirement with True-up
			(Note C & H)	(Page 1, line 9)	(Col. 3 * Col. 4)	(Note D & H)	Page 1, line 14	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8, & 9)	(Col. 6 * Page 1, line 15, Col. 9)	(Sum Col. 10 & 11)	(Note G)	(Sum Col. 12 & 13)
2a	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown	b0215	$ 12,637,431	4.289879%	$542,131	$ 10,062,081	8.416338%	$846,859	$ 259,067	$1,648,057	-	$1,648,057	(126,728)	$1,521,328
2b	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV	b0284.3	$ -	4.289879%	$0	$ -	8.416338%	$0	$ -	$0	-	$0	(5,787)	-$5,787
2c	Install 100 MVAR Dynamic Reactive Device at Airydale 500 kV substation	b0369	$ -	4.289879%	$0	$ -	8.416338%	$0	$ -	$0	-	$0	(283,576)	-$283,576
2d	Install 250 MVAR capacitor at Keystone 500 kV	b0549	$ 3.207.134	4.289879%	$137.582	$ 2.779.596	8.416338%	$233.940	$ 65.746	$437.269	-	$437.269	(34.334)	$402.934
2e	Install 25 MVAR capacitor at Saxton 115 kV substation	b0551	$ 1,380,393	4.289879%	$59,217	$ 1,091,032	8.416338%	$91,825	$ 28,022	$179,064	-	$179,064	(13,820)	$165,244
2f	Install 50 MVAR capacitor at Altoona 230 kV substation	b0552	$ 1.038.335	4.289879%	$44.543	$ 926.416	8.416338%	$77.970	$ 21.286	$143.799	-	$143.799	(9.673)	$134.126
2g	Install 50 MVAR capacitor at Raystown 230 kV substation	b0553	$ 927,947	4.289879%	$39,808	$ 803,901	8.416338%	$67,659	$ 19,023	$126,490	-	$126,490	(9,674)	$116,815
2h	Install 75 MVAR capacitor at East Towanda 230 kV substation	b0557	$ 2.177.814	4.289879%	$93.426	$ 1.887.659	8.416338%	$158.872	$ 44.210	$296.507	-	$296.507	(22.973)	$273.534
2i	Relocate the Erie South 345 kV line terminal	b1993	$ 10,675,225	4.289879%	$457,954	$ 9,842,349	8.416338%	$828,365	$ 219,910	$1,506,229	-	$1,506,229	(109,462)	$1,396,767
2j	Convert Lewis Run-Farmers Valley to 230 kV using 1033.5 ACSR conductor. Project to be completed in conjunction with new Farmers Valley 345/230 kV transformation	b1994	$ 59,253,918	4.289879%	$2,541,921	$ 57,862,961	8.416338%	$4,869,942	$ 1,250,258	$8,662,121	-	$8,662,121	(323)	$8,661,798
2k	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_DFAX_Allocation	$ 2,215,070	4.289879%	$95,024	$ 2,100,526	8.416338%	$176,787	$ 54,491	$326,302	-	$326,302	(12,623)	$313,679
2l	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_Load_Ratio Share Allocation	$ 2,215,070	4.289879%	$95,024	$ 2,100,526	8.416338%	$176,787	$ 54,491	$326,302	-	$326,302	(12,623)	$313,679
2m	Install 2nd Hunterstown 230/115 kV transformer	b2452	$ 6,023,053	4.289879%	$258,382	$ 5,752,286	8.416338%	$484,132	$ 132,507	$875,021	-	$875,021	(8,117)	$866,904
2n	Reconductor Hunterstown - Oxford 115 kV line	b2452.1	$ 2.721.544	4.289879%	$116.751	$ 2.597.151	8.416338%	$218.585	$ 59.874	$395.210	-	$395.210	(34.823)	$360.387
3	Transmission Enhancement Credit taken to Attachment H-28A Page 1. Line 7											14.922.370.36		
4	Additional Incentive Revenue taken to Attachment H-28A Page 3, Line 42										$0.00			

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

Attachment 8

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]					$ 207,489,224
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)	-	TP	1.00000	-
3	Account No. 454	(page 4, line 30)	3,761,088	TP	1.00000	3,761,088
4	Account No. 456	(page 4, line 31)	1,415,884	TP	1.00000	1,415,884
5	Revenues from Grandfathered Interzonal Transactions		-	TP	1.00000	-
6	Revenues from service provided by the ISO at a discount		-	TP	1.00000	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	14,922,370	TP	1.00000	14,922,370
8	TOTAL REVENUE CREDITS (sum lines 2-7)		20,099,342			20,099,342
9	True-up Adjustment with Interest	Attachment 13, Line 28				(14,066,555)
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				$ 173,323,326
	DIVISOR					Total
11	1 Coincident Peak (CP) (MW)			(Note A)		6,019.0
12	Average 12 CPs (MW)			(Note CC)		5,187.2
			Total			
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)	28,796.22			
			Peak Rate Total			Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	33,413.94			33,413.94
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	2,784.49			2,784.49
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	642.58			642.58
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	128.52			91.80
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	8.03			3.81

Attachment 8

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	-	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,579,600,454	TP	1.00000	1,579,600,454
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	-	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	34,881,314	W/S	1.00000	34,881,314
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	1.00000	-
6	TOTAL GROSS PLANT (sum lines 1-5)		1,614,481,768	GP=	100.000%	1,614,481,768
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	-	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	338,922,040	TP	1.00000	338,922,040
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	-	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	8,278,164	W/S	1.00000	8,278,164
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	1.00000	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		347,200,204			347,200,204
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	-			
14	Transmission	(line 2- line 8)	1,240,678,415			1,240,678,415
15	Distribution	(line 3 - line 9)	-			
16	General & Intangible	(line 4 - line 10)	26,603,150			26,603,150
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		1,267,281,564	NP=	100.000%	1,267,281,564
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 3, Col. 1 (Notes F & Y & DD)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 3, Col. 2 (Notes F & Y & DD)	(269,526,312)	NP	1.00000	(269,526,312)
21	Account No. 283 (enter negative)	Attachment 5, Line 3, Col. 3 (Notes F & Y & DD)	5,111,518	NP	1.00000	5,111,518
22	Account No. 190	Attachment 5, Line 3, Col. 4 (Notes F & Y & DD)	4,902,293	NP	1.00000	4,902,293
23	Account No. 255 (enter negative)	Attachment 5, Line 3, Col. 5 (Notes F & Y & DD)	-	NP	1.00000	-
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 9, Col. G (Note Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 10, Col. G (Note Y)	-	DA	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Regulatory Asset	Attachment 16a, 16b, 16c, line 15, Col. 7 (Notes X)	3,679,597	DA	1.00000	3,679,597
28	Unamortized Abandoned Plant	Attachment 17, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
29	TOTAL ADJUSTMENTS (sum lines 19-28)		(255,832,905)			(255,832,905)
30	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 1, Col. D) (Notes G & Y)	-	TP	1.00000	-
31	WORKING CAPITAL (Note H)					
32	CWC	1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)	8,554,467			8,278,551
33	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 2, Col. D) (Note Y)	-	TE	0.96784	-
34	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. D) (Notes B & Y)	692,368	GP	1.00000	692,368
35	TOTAL WORKING CAPITAL (sum lines 32 - 34)		9,246,835			8,970,919
36	RATE BASE (sum lines 18, 29, 30, & 35)		1,020,695,494			1,020,419,578

Attachment 8

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b (Attachment 20, page 1, line 112)	68,635,041	TE	0.96784	66,427,713
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		222,000	DA	1.00000	222,000
3	Less Account 565	321.96.b	-	DA	1.00000	-
4	Less Account 566	321.97.b	6,270,722	DA	1.00000	6,270,722
5	A&G	323.197.b (Attachment 20, page 2, line 197)	(89,854)	W/S	1.00000	(89,854)
6	Less FERC Annual Fees		-	W/S	1.00000	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		-	W/S	1.00000	-
8	Plus Transmission Related Reg. Comm. Exp. (Note I)		-	TE	0.96784	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9	(747,859)	DA	1.00000	(747,859)
10	Common	356.1	-	CE	1.00000	-
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5	860,406	DA	1.00000	860,406
12	Account 566 Amortization of Regulatory Assets	321.97.b (notes)	-	DA	1.00000	-
13	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 12	6,270,722	DA	1.00000	6,270,722
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)		6,270,722			6,270,722
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)		68,435,734			66,228,405
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)	35,306,592	TP	1.00000	35,306,592
17	General & Intangible	336.1.f & 336.10.f (Note U)	1,014,344	W/S	1.00000	1,014,344
18	Common	336.11.b (Note U)	-	CE	1.00000	-
19	Amortization of Abandoned Plant	Attachment 17, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
20	TOTAL DEPRECIATION (sum lines 16 -19)		36,320,936			36,320,936
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
21	Payroll	263.i (Attachment 7, line 1z)	443,868	W/S	1.00000	443,868
22	Highway and vehicle	263.i (Attachment 7, line 2z)	-	W/S	1.00000	-
23	PLANT RELATED					
24	Property	263.i (Attachment 7, line 3z)	76,332	GP	1.00000	76,332
25	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
26	Other	263.i (Attachment 7, line 5z)	-	GP	1.00000	-
27	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	1.00000	-
28	TOTAL OTHER TAXES (sum lines 21 - 27)		520,200			520,200
	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.89%			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		31.38%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
31	1 / (1 - T) = (from line 29)		1.4063			
32	Amortized Investment Tax Credit (266.8.f) (enter negative)		(140,188)			
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]		289,181			
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]		(333,725)			
35	Income Tax Calculation = line 30 * line 40		25,007,455	NA		25,000,695
36	ITC adjustment (line 31 * line 32)		(197,148)	NP	1.00000	(197,148)
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)		406,679	DA	1.00000	406,679
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)		(469,322)	DA	1.00000	(469,322)
39	Total Income Taxes	sum lines 35 through 38	24,747,664			24,740,904
40	RETURN	[Rate Base (page 2, line 36) * Rate of Return (page 4, line 25)]	79,700,324.33	NA		79,678,780
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 15, 20, 28, 39, 40)	209,724,858			207,489,224
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, page 2, line 4, col 11 (Note AA)	0			0
43	GROSS REV. REQUIREMENT	(line 41 + line 42)	209,724,858			207,489,224

Attachment 8

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

Mid-Atlantic Interstate Transmission, LLC

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)						1,579,600,454		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						-		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,579,600,454		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						68,635,041		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						2,207,329		
8	Included transmission expenses (line 6 less line 7)						66,427,713		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.96784		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.96784		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	-	1.00	-				
14	Distribution	354.23.b	-	0.00	-		W&S Allocator		
15	Other	354.24,25,26.b	-	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		-		-	=	1.00000	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric		W&S Allocator		
17	Electric	200.3.c	-		(line 17 / line 20)		(line 16)		CE
18	Gas	201.3.d	-		1.00000	*	1.00000	=	1.00000
19	Water	201.3.e	-						
20	Total (sum lines 17 - 19)		-						
	RETURN (R)						$		
21		Preferred Dividends (118.29c) (positive number)					-		
				(Note C)	Cost				
			$	%	(Note P)		Weighted		
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		507,592,634	41%	0.0429		0.0178	=WCLTD	
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000		
24	Common Stock (Attachment 8, Line 14, Col. 6) (Note X)		716,790,172	59%	0.1030		0.0603		
25	Total (sum lines 22-24)		1,224,382,805				0.0781	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)			(300.17.b) (Attachment 21, line 1z)			-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b) (Attachment 21, line 2z)			3,761,088		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n) (Attachment 21, line 3z)			1,415,884		

Formula Rate - Non-Levelized | Rate Formula Template | For the 12 months ended 12/31/2019

Utilizing FERC Form 1 Data

Mid-Atlantic Interstate Transmission, LLC

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

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT. Includes combined CPs for Met-Ed and Penelec zones.
B	Prepayments shall exclude prepayments of income taxes.
C	In its order approving the transfer of Penelec's and Met-Ed's transmission assets to MAIT, the Commission approved MAIT's commitment to apply a 50 percent equity/50 percent debt capital structure for ratemaking purposes for a two-year transition period. Pennsylvania Electric, 154 FERC ¶ 61,109 at P 51. Consequently, for the first two years (i.e., calendar years 2017 and 2018) the hypothetical capital structure will be used instead of the actual calculation. Per the Settlement Agreement in docket number ER17-211-000, beginning in calendar year 2019, the equity component of MAIT's capital structure to be used in calculating charges under the formula rate shall be the lower of (i) MAIT's actual equity component as calculated in accordance with Attachment 8 or (ii) 60%.
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction.
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 31).
	Inputs FIT = 21.00%
	SIT= 9.99% (State Income Tax Rate or Composite SIT)
	p = (percent of federal income tax deductible for state purposes)
L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA., and related to generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate will be set at 4.5% until such time as debt is issued by MAIT. Once debt is issued, the long-term debt cost rate will be the weighted average of the rates for all outstanding debt instruments, calculated within Attachment 10, col. j. Consistent with Note C, there will be no preferred stock cost, consistent with MAIT's commitment to use a hypothetical 50%/50% capital structure until calendar year 2019. Thereafter, Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). No change in ROE may be made absent a filing with FERC under Section 205 or Section 206 of the Federal Power Act. Per the Settlement Agreement in Docket No. ER17-211-000, MAIT's stated ROE is set to 10.30% (9.8% base ROE plus 50 basis point adder for RTO participation).
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by it own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Page 4, Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Met-Ed's and Penelec's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of Met-Ed's and Penelec's zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.
DD	Includes transmission-related balance only.

Attachment 8

Attachment H-28A, Attachment 1
page 1 of 1
For the 12 months ended 12/31/2019

Schedule 1A Rate Calculation

1	$ 2,207,329	Attachment H-28A, Page 4, Line 7
2	77,720	Revenue Credits for Sched 1A - Note A
3	$ 2,129,609	Net Schedule 1A Expenses (Line 1 - Line 2)
4	32,533,857	Annual MWh in Met-Ed and Penelec Zones - Note B
5	$ 0.0655	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

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

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

Incentive ROE Calculation

Return Calculation

			Source Reference	
1	Rate Base		Attachment H-28A, page 2, Line 36, Col. 5	1,020,419,578
2	Preferred Dividends	enter positive	Attachment H-28A, page 4, Line 21, Col. 6	0
	Common Stock			
3	Proprietary Capital		Attachment 8, Line 14, Col. 1	940,382,142
4	Less Preferred Stock		Attachment 8, Line 14, Col. 2	0
5	Less Accumulated Other Comprehensive Income Account 219		Attachment 8, Line 14, Col. 4	0
6	Less Account 216.1 & Goodwill		Attachment 8, Line 14, Col. 3 & 5	223,591,970
7	Common Stock		Attachment 8, Line 14, Col. 6	716,790,172
	Capitalization			
8	Long Term Debt		Attachment H-28A, page 4, Line 22, Col. 3	507,592,634
9	Preferred Stock		Attachment H-28A, page 4, Line 23, Col. 3	0
10	Common Stock		Attachment H-28A, page 4, Line 24, Col. 3	716,790,172
11	Total Capitalization		Attachment H-28A, page 4, Line 25, Col. 3	1,224,382,805
12	Debt %	Total Long Term Debt	Attachment H-28A, page 4, Line 22, Col. 4	41.4570%
13	Preferred %	Preferred Stock	Attachment H-28A, page 4, Line 23, Col. 4	0.0000%
14	Common %	Common Stock	Attachment H-28A, page 4, Line 24, Col. 4	58.5430%
15	Debt Cost	Total Long Term Debt	Attachment H-28A, page 4, Line 22, Col. 5	0.0429
16	Preferred Cost	Preferred Stock	Attachment H-28A, page 4, Line 23, Col. 5	0.0000
17	Common Cost	Common Stock	10.30%	0.1030
18	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 12 * Line 15)	0.0178
19	Weighted Cost of Preferred	Preferred Stock	(Line 13 * Line 16)	0.0000
20	Weighted Cost of Common	Common Stock	(Line 14 * Line 17)	0.0603
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	**0.0781**
22	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 21)**	**79,678,780**

Income Taxes

	Income Tax Rates			
23	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		Attachment H-28A, page 3, Line 29, Col. 3	28.89%
24	CIT=(T/1-T) * (1-(WCLTD/R)) =		Calculated	31.38%
25	1 / (1 - T) = (from line 23)		Attachment H-28A, page 3, Line 31, Col.3	1.4063
26	Amortized Investment Tax Credit (266.8.f) (enter negative)		Attachment H-28A, page 3, Line 32, Col. 3	(140,188.00)
27	Tax Effect of Permanent Differences and AFUDC Equity		Attachment H-28A, page 3, Line 33, Col. 3	289,180.87
28	(Excess)/Deficient Deferred Income Taxes		Attachment H-28A, page 3, Line 34, Col. 3	(333,724.86)
29	Income Tax Calculation		(line 22 * line 24)	25,000,695.09
30	ITC adjustment		(line 25 * line 26)	(197,148.28)
31	Permanent Differences and AFUDC Equity Tax Adjustment		Attachment H-28A, page 3, Line 37, Col. 3	406,678.96
32	(Excess)/Deficient Deferred Income Tax Adjustment		Attachment H-28A, page 3, Line 38, Col. 3	(469,321.78)
33	Total Income Taxes		Sum lines 29 to 32	24,740,904.00

Increased Return and Taxes

34	Return and Income taxes with increase in ROE	(Line 22 + Line 33)	104,419,683.60
35	Return without incentive adder	Attachment H-28A, Page 3, Line 40, Col. 5	79,678,779.61
36	Income Tax without incentive adder	Attachment H-28A, Page 3, Line 39, Col. 5	24,740,904.00
37	Return and Income taxes without increase in ROE	Line 35 + Line 36	104,419,683.60
38	Return and Income taxes with increase in ROE	Line 34	104,419,683.60
39	Incremental Return and incomes taxes for increase in ROE	Line 38 - Line 37	-
40	Rate Base	Line 1	1,020,419,577.97
41	Incremental Return and incomes taxes for increase in ROE divided by rate base	Line 39 / Line 40	-

Notes:

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

Attachment 8

Attachment H-28A, Attachment 3
page 1 of 1
For the 12 months ended 12/31/2019

Gross Plant Calculation

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2018		-	1,447,398,860	-	349,203	27,323,820	-	1,475,071,883
2	January	2019		-	1,468,504,659	-	349,203	27,363,741	-	1,496,217,603
3	February	2019		-	1,471,920,129	-	349,203	27,380,041	-	1,499,649,373
4	March	2019		-	1,524,030,429	-	349,203	27,386,348	-	1,551,765,980
5	April	2019		-	1,544,332,959	-	349,203	27,389,681	-	1,572,071,843
6	May	2019		-	1,579,182,702	-	349,203	28,813,364	-	1,608,345,269
7	June	2019		-	1,602,982,890	-	349,203	28,816,509	-	1,632,148,602
8	July	2019		-	1,612,689,308	-	349,203	39,642,590	-	1,652,681,101
9	August	2019		-	1,614,976,458	-	349,203	39,674,769	-	1,655,000,430
10	September	2019		-	1,624,351,632	-	349,203	42,259,156	-	1,666,959,992
11	October	2019		-	1,633,116,493	-	349,203	42,262,657	-	1,675,728,354
12	November	2019		-	1,635,594,054	-	349,203	42,277,193	-	1,678,220,450
13	December	2019		-	1,775,725,333	-	349,203	48,327,566	-	1,824,402,102
14	**13-month Average**		[A] [C]	**-**	**1,579,600,454.31**	**-**	**349,203.31**	**34,532,110.36**	**-**	**1,614,481,767.98**

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
			[B]	205.46.g	207.58.g	207.75.g	205.5.g	207.99.g	356.1	
15	December	2018			1,447,410,514		349,203	27,323,820		1,475,083,538
16	January	2019			1,468,516,313		349,203	27,363,741		1,496,229,257
17	February	2019			1,471,931,784		349,203	27,380,041		1,499,661,028
18	March	2019			1,524,042,083		349,203	27,386,348		1,551,777,635
19	April	2019			1,544,344,614		349,203	27,389,681		1,572,083,498
20	May	2019			1,579,194,356		349,203	28,813,364		1,608,356,924
21	June	2019			1,602,994,545		349,203	28,816,509		1,632,160,257
22	July	2019			1,612,700,962		349,203	39,642,590		1,652,692,755
23	August	2019			1,614,988,112		349,203	39,674,769		1,655,012,085
24	September	2019			1,624,363,287		349,203	42,259,156		1,666,971,646
25	October	2019			1,633,128,148		349,203	42,262,657		1,675,740,009
26	November	2019			1,635,605,709		349,203	42,277,193		1,678,232,105
27	December	2019			1,775,736,988		349,203	48,327,566		1,824,413,757
28	13-month Average			-	1,579,612,108.77	-	349,203.31	34,532,110.36	-	1,614,493,422.44

Asset Retirement Costs

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
			[B]	205.44.g	207.57.g	207.74.g	company records	207.98.g	company records
29	December	2018			11,654				
30	January	2019			11,654				
31	February	2019			11,654				
32	March	2019			11,654				
33	April	2019			11,654				
34	May	2019			11,654				
35	June	2019			11,654				
36	July	2019			11,654				
37	August	2019			11,654				
38	September	2019			11,654				
39	October	2019			11,654				
40	November	2019			11,654				
41	December	2019			11,654				
42	13-month Average				11,654.46	-	-	-	-

Notes:

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

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

[C] Balance excludes Asset Retirements Costs

[D] Met-Ed retained 34.5kV lines

Attachment H-28A, Attachment 4
page 1 of 1
For the 12 months ended 12/31/2019

Accumulated Depreciation Calculation

			[1] Production	[2] Transmission	[3] Distribution	[4] Intangible	[5] General	[6] Common	[7] Total
1	December	2018	-	341,987,287	-	33,051	8,206,798	-	350,227,135
2	January	2019	-	341,689,427	-	37,209	8,263,769	-	349,990,405
3	February	2019	-	342,380,628	-	41,368	8,322,395	-	350,744,391
4	March	2019	-	339,731,326	-	45,526	8,381,685	-	348,158,536
5	April	2019	-	339,156,589	-	49,684	8,441,176	-	347,647,449
6	May	2019	-	338,434,888	-	58,001	8,479,838	-	346,972,728
7	June	2019	-	338,227,060	-	53,843	8,413,450	-	346,694,353
8	July	2019	-	339,539,082	-	62,160	7,881,637	-	347,482,879
9	August	2019	-	340,576,671	-	66,318	7,998,872	-	348,641,862
10	September	2019	-	339,756,072	-	70,477	7,973,671	-	347,800,220
11	October	2019	-	338,443,007	-	74,635	8,133,454	-	346,651,097
12	November	2019	-	337,476,409	-	78,793	8,292,554	-	345,847,757
13	December	2019	-	328,588,069	-	82,952	8,072,817	-	336,743,838
14	**13-month Average**	**[A] [C]**	**-**	**338,922,039.68**	**-**	**58,001.28**	**8,220,162.84**	**-**	**347,200,203.81**

			Production	Transmission	Distribution	Intangible	General	Common	Total
		[B]	219.20-24.c	219.25.c	219.26.c	200.21.c	219.28.c	356.1	
15	December	2018		341,995,273		33,051	8,206,798		350,235,122
16	January	2019		341,697,432		37,209	8,263,769		349,998,410
17	February	2019		342,388,653		41,368	8,322,395		350,752,416
18	March	2019		339,739,369		45,526	8,381,685		348,166,580
19	April	2019		339,164,651		49,684	8,441,176		347,655,511
20	May	2019		338,442,988		58,001	8,479,838		346,980,828
21	June	2019		338,235,142		53,843	8,413,450		346,702,434
22	July	2019		339,547,201		62,160	7,881,637		347,490,998
23	August	2019		340,584,809		66,318	7,998,872		348,650,000
24	September	2019		339,764,229		70,477	7,973,671		347,808,377
25	October	2019		338,451,183		74,635	8,133,454		346,659,273
26	November	2019		337,484,604		78,793	8,292,554		345,855,952
27	December	2019		328,596,283		82,952	8,072,817		336,752,052
28	13-month Average		-	338,930,139.77	-	58,001.28	8,220,162.84	-	347,208,303.89

Reserve for Depreciation of Asset Retirement Costs

			Production	Transmission	Distribution	Intangible	General	Common
		[B]		Company Records				
29	December	2018		7,986				
30	January	2019		8,005				
31	February	2019		8,024				
32	March	2019		8,043				
33	April	2019		8,062				
34	May	2019		8,100				
35	June	2019		8,081				
36	July	2019		8,119				
37	August	2019		8,138				
38	September	2019		8,157				
39	October	2019		8,176				
40	November	2019		8,195				
41	December	2019		8,214				
42	13-month Average			8,100.08	-	-	-	-

Notes:

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

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

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

Attachment H-28A, Attachment 5
page 1 of 1
For the 12 months ended 12/31/2019

ADIT Calculation

				[1]	[2]	[3]	[4]	[5]	[6]
				ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below					
				Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
				(enter negative)	**(enter negative)**	**(enter negative)**		**(enter negative)**	
					[C]	[D]	[E]	[F]	
1	December 31	2018		-	(265,865,581)	5,758,572	4,808,250	-	(255,298,759)
2	December 31	2019		-	(273,187,044)	4,464,464	4,996,335	-	(263,726,244)
3	**Begin/End Average**		**[A]**	**-**	**(269,526,312)**	**5,111,518**	**4,902,293**	**-**	**(259,512,501)**

				Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
				ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjustments from notes below)					
			[B]	273.8.k	275.2.k	277.9.k	234.8.c	267.h	
4	December 31	2018			192,621,807	(31,144,661)	9,507,394	2,329,470	173,314,009
5	December 31	2019			216,161,554	(26,910,650)	10,608,504	2,229,785	202,089,193
6	Begin/End Average			-	204,391,680	(29,027,656)	10,057,949	2,279,628	187,701,601

Notes:

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

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

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

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Other: [H]	Other: [H]	Normalization [G]
2018	-	(7,672,554)	(65,571,221)		-	-	-
2019	-	(7,487,594)	(63,262,972)		-	-	13,725,076

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

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Other: [H]	Other: [H]	Normalization [G]
2018	-	-	(25,386,089)		-	-	-
2019	-	-	(24,872,166)	-	-	-	2,425,980

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

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Other: [H]	Other: [H]	Normalization [G]
2018	-	-	(2,741,496)	7,440,640	-	-	-
2019	-	-	(2,454,604)	7,714,182	-	-	352,591

[F] See Attachment H-28A, page 5, note K; A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f).

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

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

ADIT Normalization Calculation

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
	2019 Quarterly Activity and Balances							
Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
4,808,250	117,673	4,925,923	127,168	5,053,091	134,254	5,187,345	161,581	5,348,926
Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
4,808,250	**88,980**		**64,455**		**34,207**		**443**	
Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
265,865,581	4,580,572	270,446,153	4,950,197	275,396,351	5,226,018	280,622,368	6,289,751	286,912,119
Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
265,865,581	**3,463,666**		**2,509,004**		**1,331,561**		**17,232**	
Beginning 283 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
(5,758,572)	809,641	(4,948,931)	874,974	(4,073,958)	923,726	(3,150,231)	1,111,747	(2,038,484)
Beginning 283 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
(5,758,572)	**612,221**		**443,480**		**235,360**		**3,046**	

Attachment H-28A, Attachment 5a
page 2 of 2
For the 12 months ended 12/31/2019

ADIT Normalization Calculation

		[1]	[2]	[3]	[4]	[5]
2019 Activity		**FERC Form 1 - Year-End (sourced from Attachment 5, page 1, line 5)**	**Prorated year-end less FERC Form 1 Year-end**	**Sum of FAS143, FAS106, FAS109, CIAC and Other from Attachment 5, page 1, notes**	**Total Normalization to Attachment 5 (col. 2 - col. 3)**	**Ending Balance for formula rate (col. 1 - col. 3. - col. 4)**
Pro-rated Total	**Pro-rated Ending 190**					
188,085	**4,996,335**	10,608,504	5,612,168	5,259,578	**352,591**	4,996,335
Pro-rated Total	**Pro-rated Ending 282**					
7,321,463	**273,187,044**	216,161,554	(57,025,490)	(70,750,565)	**13,725,076**	273,187,044
Pro-rated Total	**Pro-rated Ending 283**					
1,294,108	**(4,464,464)**	(26,910,650)	(22,446,185)	(24,872,166)	**2,425,980**	(4,464,464)

Attachment H-28A, Attachment 5b
page 1 of 3

ADIT Detail
For the 12 months ended 12/31/2019

	COLUMN A	COLUMN B	COLUMN C	COLUMN D
		BALANCE AS OF 12-31-18	BALANCE AS OF 12-31-19	AVERAGE BALANCE
	ACCOUNT 255:			
	Investment Tax Credit	2,329,470	2,229,785	2,279,628
1	TOTAL ACCOUNT 255	2,329,470	2,229,785	
	ACCOUNT 282:			
	263A Capitalized Overheads	22,418,718	21,715,298	22,067,008
	Accelarated Depreciation	198,690,005	212,782,324	205,736,165
	AFUDC	3,424,100	3,399,705	3,411,902
	AFUDC Equity (FAS109)	2,770,189	4,622,409	3,696,299
	Capitalized Interest	0	0	0
	Capitalized Tree Trimming	9,940,106	9,707,754	9,823,930
	Casualty Loss	1,889,953	1,058,888	1,474,421
	Contribution in Aid of Construction	0	0	0
	OPEBs	(7,672,554)	(7,487,594)	(7,580,074)
	Other	(8,918,442)	(8,863,372)	(8,890,907)
	Pension and Capitalized Benefits	5,376,578	5,226,600	5,301,589
	Tax Repairs	33,044,562	41,884,921	37,464,742
	FAS109 Related to Property	(68,341,410)	(67,885,381)	(68,113,395)
2	TOTAL ACCOUNT 282	192,621,807	216,161,554	

ADIT Detail

For the 12 months ended 12/31/2019

		COLUMN A	COLUMN B	COLUMN C	COLUMN D
			BALANCE AS OF 12-31-18	BALANCE AS OF 12-31-19	AVERAGE BALANCE
	ACCOUNT 283:				
	AFUDC Equity Flow Thru (Gross up)		1,125,565	1,878,147	1,501,856
	Property FAS109		(26,654,131)	(26,585,408)	(26,619,769)
	Deferred Storm Costs		152,064	76,032	114,048
	Vegetation Management - Transmission		1,035,343	862,786	949,065
	PJM Payable		(6,945,979)	(2,977,302)	(4,961,641)
	Fed Rate Change - Non-Prop. Gross-up		142,476	(164,905)	(11,215)
3	TOTAL ACCOUNT 283		(31,144,661)	(26,910,650)	

Attachment H-28A, Attachment 5b
page 3 of 3

ADIT Detail

For the 12 months ended 12/31/2019

	COLUMN A	COLUMN B	COLUMN C	COLUMN D
		BALANCE AS OF 12-31-18	BALANCE AS OF 12-31-19	AVERAGE BALANCE
	ACCOUNT 190:			
	Capitalized Interest	3,861,755	4,442,934	4,152,345
	Contribution in Aid of Construction	7,440,640	7,714,182	7,577,411
	Property FAS109	(2,741,496)	(2,454,604)	(2,598,050)
	Investment Tax Credit	946,495	905,992	926,244
4	TOTAL ACCOUNT 190	9,507,394	10,608,504	10,057,949

Attachment H-28A, Attachment 7
page 1 of 1
For the 12 months ended 12/31/2019

Taxes Other than Income Calculation

		[A]	Dec 31, 2019
1	**Payroll Taxes**		
1a	FICA	263.i	443,868
1b		263.i	-
1c		263.i	-
1z	**Payroll Taxes Total**		443,868
2	**Highway and Vehicle Taxes**		
2a		263.i	-
2z	**Highway and Vehicle Taxes**		-
3	**Property Taxes**		
3a	Property Tax	263.i	76,332
3b			-
3c			-
3z	**Property Taxes**		76,332
4	**Gross Receipts Tax**		
4a		263.i	-
4z	**Gross Receipts Tax**		-
5	**Other Taxes**		
5a		263.i	-
5b		263.i	-
5c			-
5z	**Other Taxes**		-
6z	**Payments in lieu of taxes**		
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]		$520,200

Notes:

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

Attachment 9

PATH Formula Rate for January 1, 2019 to December 31, 2019

Attachment 9

ALSTON & BIRD

The Atlantic Building
950 F Street, NW
Washington, DC 20004-1404
202-239-3300 | Fax: 202-239-3333

September 4, 2018

To: Parties to FERC Docket No. ER08-386-000

Re: Potomac-Appalachian Transmission Highline, LLC
PJM Open Access Transmission Tariff, Attachment H-19
Projected Transmission Revenue Requirement for Rate Year 2019

Pursuant to section IV of the Formula Rate Implementation Protocols ("Protocols") set forth in Attachment H-19B of the PJM Open Access Transmission Tariff ("PJM OATT"),[1] Potomac-Appalachian Transmission Highline, LLC ("PATH"), on behalf of its operating companies PATH West Virginia Transmission Company, LLC and PATH Allegheny Transmission Company, LLC, is submitting a Projected Transmission Revenue Requirement for Rate Year 2019 ("2019 PTRR") to PJM for posting.

The 2019 PTRR was developed pursuant to the PATH formula rate as set forth in Attachment H-19 of the PJM OATT. PATH has asked PJM to post a copy of the 2019 PTRR to the transmission service formula rates section of its internet site, located at:

https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx

A copy of the 2019 PTRR is attached. Pursuant to section IV.C of the Protocols, within two business days of this submission to PJM, PATH will provide notice on PJM's website of the time, date and location of an open meeting among Interested Parties.

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[1] PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1.

For the 12 months ended 12/31/2019

SUMMARY

		PATH West Virginia Transmission Company, LLC (PATH-WV) (1)		PATH Allegheny Transmission Company, LLC (PATH-Allegheny) (2)		Potomac-Appalachian Transmission Highline, LLC (3) = (1) + (2)
1	NET REVENUE REQUIREMENT	$2,178,888	(A)	$1,573,733	(B)	$3,752,620
2	PJM Project No.					
3	b0490 & b0491	$2,178,888	(C)			$2,178,888
4	b0492 & b0560			$1,573,733	(D)	$1,573,733
5						
6	Total (Sum lines 3 to 5)	$2,178,888		$1,573,733		$3,752,620

Sources:	(A)	Rate Formula Template, page 2, line 5, col. (3)
	(B)	Rate Formula Template, page 7, line 5, col. (3)
	(C)	Rate Formula Template - Attachment 5, page 30 col., (7)
	(D)	Rate Formula Template - Attachment 5, page 31 col., (6)

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

PATH West Virginia Transmission Company, LLC

Line No.			(1)	(2)		(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)		12 months		$ 806,046
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	$ -
3	True-up Adjustment with Interest	Protocols	1,372,842	DA	1.00000	$ 1,372,842
4a	Accelerated True-up Adjustment with Interest		0	DA	1.00000	$ -
4b	Interest on Gains or Recoveries in Account 254	Company Records	0	DA	1.00000	-
5	NET REVENUE REQUIREMENT	(Lines 1 minus line 2 plus line 3 plus line 4a and 4b)				$ 2,178,888

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

PATH West Virginia Transmission Company, LLC

Line No.	(1)	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
6	Production	(Attachment 4)	-	NA	0.00000	-
7	Transmission	(Attachment 4)	-	TP	1.00000	-
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	-	GP=	1.00000	-
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	-	TP	1.00000	-
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		-			-
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	-			-
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	-			-
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	-	NP=	1.0000	-
26	ADJUSTMENTS TO RATE BASE (Note A)					
27	Account No. 281 (enter negative)	(Attachment 4)	-	NA	0.00000	-
28	Account No. 282 (enter negative)	(Attachment 4)	-	NP	1.00000	-
29	Account No. 283 (enter negative)	(Attachment 4)	1,277,479	NP	1.00000	1,277,479
30	Account No. 190	(Attachment 4)	3,358,107	NP	1.00000	3,358,107
31	Account No. 255 (enter negative)	(Attachment 4)	-	NP	1.00000	-
32	CWIP	(Attachment 4)	-	DA	1.00000	-
33	Unamortized Regulatory Asset	(Attachment 4)	-	DA	1.00000	-
34	Unamortized Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
35	TOTAL ADJUSTMENTS (sum lines 27-34)		4,635,586			4,635,586
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	54,795			54,795
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	-	GP	1.00000	-
41	TOTAL WORKING CAPITAL (sum lines 38-40)		54,795			54,795
42	RATE BASE (sum lines 25, 35, 36, & 41)		4,690,381			4,690,381

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2019

PATH West Virginia Transmission Company, LLC

	(1)	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
43	O&M					
44	Transmission	321.112.b	-	TE	1.00000	-
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566 (Misc Trans Expense)	Line 56	-	DA	1.00000	-
47	A&G	323.197.b	424,665	W/S	1.00000	424,665
48	Less EPRI & Reg. Comm. Exp. & Other Ad.	(Note D & Attach 4)	-	DA	1.00000	-
49	Plus Transmission Related Reg. Comm. Exp.	(Note D & Attach 4)	-	TE	1.00000	-
50	PBOP Expense adjustment	(Attachment 4)	13,695			13,695
51	Common	(Attachment 4)	-	CE	1.00000	-
52	Transmission Lease Payments	200.4.c	-	DA	1.00000	-
53	Account 566					
54	Amortization of Regulatory Asset	Attachment 4	-	DA	1.00000	-
55	Miscellaneous Transmission Expense	Attachment 4	-	DA	1.00000	-
56	Total Account 566		-			-
57	TOTAL O&M (sum lines 44, 47, 49, 50, 51, 52, 56 less lines 45, 46 & 48)		438,360			438,360
58	DEPRECIATION EXPENSE					
59	Transmission	336.7.b & c	-	TP	1.00000	-
60	General and Intangible	336.1.d&e + 336.10.b&c	-	W/S	1.00000	-
61	Common	336.11.b&c	-	CE	1.00000	-
62	Amortization of Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
63	TOTAL DEPRECIATION (Sum lines 59-62)		-			-
64	TAXES OTHER THAN INCOME TAXES (Note E)					
65	LABOR RELATED					
66	Payroll	263i	-	W/S	1.00000	-
67	Highway and vehicle	263i	-	W/S	1.00000	-
68	PLANT RELATED					
69	Property	263i	-	GP	1.00000	-
70	Gross Receipts	263i	-	NA	0.00000	-
71	Other	263i	-	GP	1.00000	-
72	Payments in lieu of taxes		-	GP	1.00000	-
73	TOTAL OTHER TAXES (sum lines 66-72)		-			-
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		26.13%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		22.39%			
77	where WCLTD=(line 118) and R= (line 121)					
78	and FIT, SIT & p are as given in footnote F.					
79	1 / (1 - T) = (T from line 75)		1.3537			
80	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
81	Income Tax Calculation = line 76 * line 85		67,267	NA		67,267
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	67,267			67,267
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		300,419	NA		300,419
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		806,046			806,046

Attachment A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

PATH West Virginia Transmission Company, LLC

SUPPORTING CALCULATIONS AND NOTES

87	TRANSMISSION PLANT INCLUDED IN ISO RATES								
88	Total transmission plant (line 7, column 3)						0		
89	Less transmission plant excluded from ISO rates (Note H)						0		
90	Less transmission plant included in OATT Ancillary Services (Note H)						0		
91	Transmission plant included in ISO rates (line 88 less lines 89 & 90)						0		
92	Percentage of transmission plant included in ISO Rates (line 91 divided by line 88) [If line 88 equal zero, enter 1)					TP=	1.0000		
93	TRANSMISSION EXPENSES								
94									
95	Total transmission expenses (line 44, column 3)						0		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						0		
98	Percentage of transmission expenses after adjustment (line 97 divided by line 95) [If line 95 equal zero, enter 1)						1.00000		
99	Percentage of transmission plant included in ISO Rates (line 92)					TP	1.00000		
100	Percentage of transmission expenses included in ISO Rates (line 98 times line 99)					TE=	1.00000		
101	WAGES & SALARY ALLOCATOR (W&S)								
102		Form 1 Reference	$	TP	Allocation				
103	Production	354.20.b	0						
104	Transmission	354.21.b	0	1.00	0				
105	Distribution	354.23.b	0				W&S Allocator		
106	Other	354.24,25,26.b	0				($ / Allocation)		
107	Total (sum lines 103-106) [TP equals 1 if there are no wages & salaries]		0		0	=	1.00000	=	WS
108	COMMON PLANT ALLOCATOR (CE) (Note I)								
109			**$**		% Electric		W&S Allocator		
110	Electric	200.3.c	0		(line 110 / line 113)		(line 107)		CE
111	Gas	201.3.d	0		1.00000	x	1.00000	=	1.00000
112	Water	201.3.e	0						
113	Total (sum lines 110 - 112)		0						
114	RETURN (R)						$		
115									
116									
117			$	%	Cost		Weighted		
118	Long Term Debt (Note K)	(Attachment 4)	0	50%	4.70%		0.0235	=WCLTD	
119	Preferred Stock	(Attachment 4)	0	0%	0.00%		0.0000		
120	Common Stock (Note J)	(Attachment 4)	0	50%	8.11%		0.0406		
121	Total (sum lines 118-120)		0				0.0641	=R	

SUPPORTING CALCULATIONS AND NOTES

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2019

PATH West Virginia Transmission Company, LLC

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

Note Letter

A The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.

B Identified in Form 1 as being only transmission related.

C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1.

D EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, except safety, education and out-reach related advertising included in Account 930.1. Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

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

F The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 4, line 79).

Inputs Required:	FIT =	21.00%	
	SIT=	6.49%	(State Income Tax Rate or Composite SIT from Attachment 4)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

G Removes dollar amount of transmission expenses included in the OATT ancillary services rates, if any.

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

I Enter dollar amounts

J Effective Janaury 19, 2017, the ROE will be 8.11%. The true up for Rate Year 2017 will be computed using an ROE that is a time-weighted average of the pre-January 19, 2017 ROE and the post-January 19, 2017 ROE. Examaple Calculation: For the first 18 days of 2017, the authorized ROE will be 10.4%, and for the remaining 347 days of 2017, the authorized ROE will be 8.11%. Therefore, the weighted ROE = (18 days* 10.40% + 347 days*8.11%)/365 days=8.22%.

K The percentage shown for Long Term Debt is subject to the Annual Update and Attachment 9. Pursuant to the Stipulation Agreement entered into on April 6, 2015 in FERC Docket Nos. ER09-1256-002 and ER12-2708-003, the Long Term Debt rate is 4.70% effective December 1, 2012.

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

PATH Allegheny Transmission Company, LLC

Line No.			(1)	(2)		(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)		12 months		$ 222,174
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	-
3	True-up Adjustment with Interest	Protocols	1,351,559	DA	1.00000	$ 1,351,559
4a	Accelerated True-up Adjustment with Interest		0	DA	1.00000	-
4b	Interest on Gains or Recoveries in Account 254	Company Records	0	DA	1.00000	-
5	NET REVENUE REQUIREMENT	(Lines 1 minus line 2 plus line 3 plus line 4a and 4b)				$ 1,573,733

Attachment A
Formula Rate - Non-Levelized
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

PATH Allegheny Transmission Company, LLC

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
6	Production	(Attachment 4)	-	NA	0.00000	-
7	Transmission	(Attachment 4)	-	TP	1.00000	-
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	-	GP=	1.00000	-
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	-	TP	1.00000	-
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		-			-
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	-			-
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	-			-
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	-	NP=	1.0000	-
26	ADJUSTMENTS TO RATE BASE (Note A)					
27	Account No. 281 (enter negative)	(Attachment 4)	-	NA	0.00000	-
28	Account No. 282 (enter negative)	(Attachment 4)	-	NP	1.00000	-
29	Account No. 283 (enter negative)	(Attachment 4)	-	NP	1.00000	-
30	Account No. 190	(Attachment 4)	953,796	NP	1.00000	953,796
31	Account No. 255 (enter negative)	(Attachment 4)	-	NP	1.00000	-
32	CWIP	(Attachment 4)	-	DA	1.00000	-
33	Unamortized Regulatory Asset	(Attachment 4)	-	DA	1.00000	-
34	Unamortized Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
35	TOTAL ADJUSTMENTS (sum lines 27-34)		953,796			953,796
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	18,466			18,466
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	-	GP	1.00000	-
41	TOTAL WORKING CAPITAL (sum lines 38-40)		18,466			18,466
42	RATE BASE (sum lines 25, 35, 36, & 41)		972,261			972,261

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2019

PATH Allegheny Transmission Company, LLC

	(1)	(2)	(3)	(4)		(5)
		Form No. 1 Page, Line, Col.	**Company Total**	**Allocator**		**Transmission** (Col 3 times Col 4)
43	O&M					
44	Transmission	321.112.b	59,523	TE	1.00000	59,523
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566	Line 56	59,523	DA	1.00000	59,523
47	A&G	323.197.b	88,202	W/S	1.00000	88,202
48	Less EPRI & Reg. Comm. Exp. & Other Ad.	(Note D & Attach 4)	-	DA	1.00000	-
49	Plus Transmission Related Reg. Comm. Exp.	(Note D & Attach 4)	-	TE	1.00000	-
50	PBOP Expense adjustment	(Attachment 4)	-			-
51	Common	(Attachment 4)	-	CE	1.00000	-
52	Transmission Lease Payments	200.4.c	-	DA	1.00000	-
53	Account 566					
54	Amortization of Regulatory Asset	Attachment 4	-	DA	1.00000	-
55	Miscellaneous Transmission Expense	Attachment 4	59,523	DA	1.00000	59,523
56	Total Account 566		59,523			59,523
57	TOTAL O&M (sum lines 44, 47, 49, 50, 51, 52, 56 less lines 45,46, 48)		147,725			147,725
58	DEPRECIATION EXPENSE					
59	Transmission	336.7.b & c	-	TP	1.00000	-
60	General and Intangible	336.1.d&e + 336.10.b.c.d&e	-	W/S	1.00000	-
61	Common	336.11.b & c	-	CE	1.00000	-
62	Amortization of Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
63	TOTAL DEPRECIATION (Sum lines 59-62)		-			-
64	TAXES OTHER THAN INCOME TAXES (Note E)					
65	LABOR RELATED					
66	Payroll	263i	-	W/S	1.00000	-
67	Highway and vehicle	263i	-	W/S	1.00000	-
68	PLANT RELATED					
69	Property	263i	-	GP	1.00000	-
70	Gross Receipts	263i	-	NA	0.00000	-
71	Other	263i	-	GP	1.00000	-
72	Payments in lieu of taxes		-	GP	1.00000	-
73	TOTAL OTHER TAXES (sum lines 66-72)		-			-
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		23.60%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		19.55%			
77	where WCLTD=(line 118) and R= (line 121)					
78	and FIT, SIT & p are as given in footnote F.					
79	1 / (1 - T) = (T from line 75)		1.3088			
80	Amortized Investment Tax Credit	(266.8f) (enter negative)	0			
81	Income Tax Calculation = line 76 * line 85		12,176	NA		12,176
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	12,176			12,176
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		62,273	NA		62,273
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		222,174			222,174

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2019

PATH Allegheny Transmission Company, LLC
SUPPORTING CALCULATIONS AND NOTES

87	TRANSMISSION PLANT INCLUDED IN ISO RATES								
88	Total transmission plant (line 7, column 3)						0		
89	Less transmission plant excluded from ISO rates (Note H)						0		
90	Less transmission plant included in OATT Ancillary Services (Note H)						0		
91	Transmission plant included in ISO rates (line 88 less lines 89 & 90)						0		
92	Percentage of transmission plant included in ISO Rates (line 91 divided by line 88) [If line 88 equal zero, enter 1)					TP=	1.0000		
93	TRANSMISSION EXPENSES								
94									
95	Total transmission expenses (line 44, column 3)						59,523		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						59,523		
98	Percentage of transmission expenses after adjustment (line 97 divided by line 95) [If line 95 equal zero, enter 1)						1.00000		
99	Percentage of transmission plant included in ISO Rates (line 92)					TP	1.00000		
100	Percentage of transmission expenses included in ISO Rates (line 98 times line 99)					TE=	1.00000		
101	WAGES & SALARY ALLOCATOR (W&S)								
102		Form 1 Reference	$	TP	Allocation				
103	Production	354.20.b	0						
104	Transmission	354.21.b	0	1.00	0				
105	Distribution	354.23.b	0				W&S Allocator		
106	Other	354.24,25,26.b	0	1.00	0		($ / Allocation)		
107	Total (sum lines 103-106) [TP equals 1 if there are no wages & salaries]		0		0	=	1.00000	=	WS
108	COMMON PLANT ALLOCATOR (CE) (Note I)								
109			**$**		% Electric		W&S Allocator		
110	Electric	200.3.c	0		(line 110 / line 113)		(line 107)		CE
111	Gas	201.3.d	0		1.00000	x	1.00000	=	1.00000
112	Water	201.3.e	0						
113	Total (sum lines 110 - 112)		0						
114	RETURN (R)						$		
115									
116									
117			$	%	Cost		Weighted		
118	Long Term Debt (Note K)	(Attachment 4)	0	50%	4.70%		0.0235	=WCLTD	
119	Preferred Stock	(Attachment 4)	0	0%	0.00%		0.0000		
120	Common Stock (Note J)	(Attachment 4)	0	50%	8.11%		0.0406		
121	Total (sum lines 118-120)		0				0.0641	=R	

SUPPORTING CALCULATIONS AND NOTES

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2019

PATH Allegheny Transmission Company, LLC

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

Note Letter

A The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.

B Identified in Form 1 as being only transmission related.

C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1.

D EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, except safety, education, siting and out-reach related advertising included in Account 930.1. Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

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

F The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 9, line 79).

Inputs Required:	FIT =	21.00%	
	SIT=	3.29%	(State Income Tax Rate or Composite SIT from Attachment 4)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

G Removes dollar amount of transmission expenses included in the OATT ancillary services rates, if any.

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

I Enter dollar amounts

J Effective Janaury 19, 2017, the ROE will be 8.11%. The true up for Rate Year 2017 will be computed using an ROE that is a time-weighted average of the pre-January 19, 2017 ROE and the post-January 19, 2017 ROE. Examaple Calculation: For the first 18 days of 2017, the authorized ROE will be 10.4%, and for the remaining 347 days of 2017, the authorized ROE will be 8.11%. Therefore, the weighted ROE = (18 days* 10.40% + 347 days*8.11%)/365 days=8.22%.

K The percentage shown for Long Term Debt is subject to the Annual Update and Attachment 9. Pursuant to the Stipulation Agreement entered into on April 6, 2015 in FERC Docket Nos. ER09-1256-002 and ER12-2708-003, the Long Term Debt rate is 4.70% effective December 1, 2012.

Attachment 1 - Revenue Credit Workpaper
PATH West Virginia Transmission Company, LLC

	Account 454 - Rent from Electric Property		
1	Rent from FERC Form No. 1 - Note 6		-
2	Other Electric Revenues	See	-
3	Schedule 1A		-
4	PTP Serv revs for which the load is not included in the divisor received by TO		-
5	PJM Transitional Revenue Neutrality (Note 1)		-
6	PJM Transitional Market Expansion (Note 1)		-
7	Professional Services (Note 3)		-
8	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
9	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
10	Gross Revenue Credits	Sum lines 2-9 + line 1	-
11	Less line 20	less line 18	-
12	Total Revenue Credits	line 10 + line 11	-
13	Revenues associated with lines 13 thru 18 are to be included in lines 1-9 and total of those revenues entered here		-
14	Income Taxes associated with revenues in line 15		-
15	One half margin (line 13 - line 14)/2		-
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		-
18	Line 13 less line 17		-

Note 1 All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on page 2, line 2 of Rate Formula Template.

Note 2 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 3 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). DLC will retain 50% of net revenues consistent with *Pacific Gas and Electric Company* , 90 FERC ¶ 61,314. Note: in order to use lines 15 - 20, 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).

Note 4 If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support. For example revenues associated with distribution facilities. In addition Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12.

Attachment 1 - Revenue Credit Workpaper
PATH West Virginia Transmission Company, LLC

Note 5 Other electric Revenues - includes revenues for various related electricity products/premium services such as surge protectors and appliance guards

Note 6 All Account 454 and 456 Revenues must be itemized below

Account 454	Include	$
Joint pole attachments - telephone	Include	-
Joint pole attachments - cable	Include	-
Underground rentals	Include	-
Transmission tower wireless rentals	Include	-
Other rentals	Include	-
Corporate headquarters sublease	Include	-
Misc non-transmission rentals	Include	-
Customer commitment services	Include	-
xxxx		
xxxx		
Total		-
Account 456	Include	-
Other electric revenues	Include	-
Transmission Revenue - Firm	Include	-
Transmission Revenue - Non-Firm	Include	-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
Total		-
Total Account 454 and 456 included		-
Payments by PJM of the revenue requirement calculated on Rate Formula Template	Exclude	-
Total Account 454 and 456 included and excluded		-

Attachment 1 - Revenue Credit Workpaper
PATH Allegheny Transmission Company, LLC

	Account 454 - Rent from Electric Property		
1	Rent from FERC Form No. 1 - Note 6		-
2	Other Electric Revenues	See Note 5	-
3	Schedule 1A		-
4	PTP Serv revs for which the load is not included in the divisor received by TO		-
5	PJM Transitional Revenue Neutrality (Note 1)		-
6	PJM Transitional Market Expansion (Note 1)		-
7	Professional Services (Note 3)		-
8	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
9	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
10	Gross Revenue Credits	Sum lines 2-9 + line 1	-
11	Less line 20	less line 18	-
12	Total Revenue Credits	line 10 + line 11	-
13	Revenues associated with lines 13 thru 18 are to be included in lines 1-9 and total of those revenues entered here		-
14	Income Taxes associated with revenues in line 15		-
15	One half margin (line 13 - line 14)/2		-
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		-
18	Line 13 less line 17		-

Note 1 All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on page 7, line 2 of Rate Formula Template.

Note 2 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 3 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). DLC will retain 50% of net revenues consistent with *Pacific Gas and Electric Company* , 90 FERC ¶ 61,314. Note: in order to use lines 15 - 20, 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).

Note 4 If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support. For example revenues associated with distribution facilities. In addition Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12.

Note 5 Other electric Revenues - includes revenues for various related electricity products/premium services such as surge protectors and appliance guards

Attachment 1 - Revenue Credit Workpaper
PATH Allegheny Transmission Company, LLC

Note 6	All Account 454 and 456 Revenues must be itemized below		
	Account 454	Include	$
	Joint pole attachments - telephone	Include	-
	Joint pole attachments - cable	Include	-
	Underground rentals	Include	-
	Transmission tower wireless rentals	Include	-
	Other rentals	Include	-
	Corporate headquarters sublease	Include	-
	Misc non-transmission rentals	Include	-
	Customer commitment services	Include	-
	xxxx		
	xxxx		
	Total		-
	Account 456	Include	-
	Other electric revenues	Include	-
	Transmission Revenue - Firm	Include	-
	Transmission Revenue - Non-Firm	Include	-
	xxxx		-
	xxxx		-
	xxxx		-
	xxxx		-
	xxxx		-
	xxxx		-
	xxxx		-
	Total		-
	Total Account 454 and 456 included		-
	Payments by PJM of the revenue requirement calculated on Rate Formula Template	Exclude	-
	Total Account 454 and 456 included and excluded		-

Attachment 2 has been removed and intentionally left blank.

Attachment 2 has been removed and intentionally left blank.

Attachment 3 - Calculation of Carrying Charges

PATH West Virginia Transmission Company, LLC

1 Calculation of Composite Depreciation Rate

2	Transmission Plant @ Beginning of Period	(Attachment 4)	-
3	Transmission Plant @ End of Period	(Attachment 4)	-
4	Sum	(sum lines 2 & 3)	-
5	Average Balance of Transmission Investment	(line 4/2)	-
6	Depreciation Expense	Rate Formula Template	-
7	Composite Depreciation Rate	(line 6/ line 5)	0.00%
8	Depreciable Life for Composite Depreciation Rate	(1/line 7)	-
9	Round line 8 to nearest whole year		-

Attachment 3 - Calculation of Carrying Charges

PATH Allegheny Transmission Company, LLC

1 Calculation of Composite Depreciation Rate

2	Transmission Plant @ Beginning of Period	(Attachment 4)	-
3	Transmission Plant @ End of Period	(Attachment 4)	-
4	Sum	(sum lines 2 & 3)	-
5	Average Balance of Transmission Investment	(line 4/2)	-
6	Depreciation Expense	Rate Formula Template	-
7	Composite Depreciation Rate	(line 6/ line 5)	0.00%
8	Depreciable Life for Composite Depreciation Rate	(1/line 7)	-
9	Round line 8 to nearest whole year		-

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

Plant in Service Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
1	**Calculation of Transmission Plant In Service**	Source	Year	Balance
2	December	p206.58.b	2018	-
3	January	company records	2019	-
4	February	company records	2019	-
5	March	company records	2019	-
6	April	company records	2019	-
7	May	company records	2019	-
8	June	company records	2019	-
9	July	company records	2019	-
10	August	company records	2019	-
11	September	company records	2019	-
12	October	company records	2019	-
13	November	company records	2019	-
14	December	p207.58.g	2019	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2018	-
18	January	company records	2019	-
19	February	company records	2019	-
20	March	company records	2019	-
21	April	company records	2019	-
22	May	company records	2019	-
23	June	company records	2019	-
24	July	company records	2019	-
25	August	company records	2019	-
26	September	company records	2019	-
27	October	company records	2019	-
28	November	company records	2019	-
29	December	p207.75.g	2019	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5.b	2018	-
33	December	p205.5.g	2019	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2018	-
37	December	p207.99.g	2019	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2018	-
41	January	company records	2019	-
42	February	company records	2019	-
43	March	company records	2019	-
44	April	company records	2019	-
45	May	company records	2019	-
46	March	Attachment 6	2019	-
47	April	company records	2019	-
48	August	company records	2019	-
49	September	company records	2019	-
50	October	company records	2019	-
51	November	company records	2019	-
52	December	p205.46.g	2019	-
53	**Production Plant In Service**	(sum lines 40-52) /13		-

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

		Source	Year	Balance
54	**Calculation of Common Plant In Service**	Source	Year	Balance
55	December (Electric Portion)	p356	2018	-
56	December (Electric Portion)	p356	2019	-
57	**Common Plant In Service**	(sum lines 55 & 56) /2		-
58	**Total Plant In Service**	(sum lines 15, 30, 34, 38, 53, & 57)		-

Accumulated Depreciation Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
59	**Calculation of Transmission Accumulated Depreciation**	Source	Year	Balance	
60	December	Prior year p219.25	2018	-	
61	January	company records	2019	-	
62	February	company records	2019	-	
63	March	company records	2019	-	
64	April	company records	2019	-	
65	May	company records	2019	-	
66	June	company records	2019	-	
67	July	company records	2019	-	
68	August	company records	2019	-	
69	September	company records	2019	-	
70	October	company records	2019	-	
71	November	company records	2019	-	
72	December	p219.25	2019	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2018	-	
76	January	company records	2019	-	
77	February	company records	2019	-	
78	March	company records	2019	-	
79	April	company records	2019	-	
80	May	company records	2019	-	
81	June	company records	2019	-	
82	July	company records	2019	-	
83	August	company records	2019	-	
84	September	company records	2019	-	
85	October	company records	2019	-	
86	November	company records	2019	-	
87	December	p219.26	2019	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2018	-	
91	December	p200.21c	2019	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2018	-	
95	December	p219.28	2019	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

		Source	Year	Balance
97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2018	-
99	January	company records	2019	-
100	February	company records	2019	-
101	March	company records	2019	-
102	April	company records	2019	-
103	May	company records	2019	-
104	June	company records	2019	-
105	July	company records	2019	-
106	August	company records	2019	-
107	September	company records	2019	-
108	October	company records	2019	-
109	November	company records	2019	-
110	December	p219.20 thru 219.24	2019	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2018	-
114	December (Electric Portion)	p356	2019	-
115	**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-
116	**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		-

ADJUSTMENTS TO RATE BASE **(Note A)**

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
			Beginning of Year	End of Year	Average Balance
117	Account No. 281 (enter negative)	273.8.k	-	-	0
118	Account No. 282 (enter negative)	275.2.k	-	-	0
119	Account No. 283 (enter negative)	277.9.k	1,290,872	1,264,086	1,277,479
120	Account No. 190	234.8.c	3,398,564	3,317,650	3,358,107
121	Account No. 255 (enter negative)	267.8.h	-	-	0

122	**Unamortized Abandoned Plant**	Per FERC Order					
123	**Monthly Balance**	Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
124	December	p111.71.d (and Notes)	0				-
125	January	company records		-		-	-
126	February	company records		-		-	-
127	March	company records		-		-	-
128	April	company records		-		-	-
129	May	company records		-		-	-
130	June	company records		-		-	-
131	July	company records		-		-	-
132	August	company records		-		-	-
133	September	company records		-		-	-
134	October	company records		-		-	-
135	November	company records		-		-	-
136	December	p111.71.c (and Notes) Detail on p230b		-		-	-
137	**Ending Balance is a 13-Month Average**	(sum lines 124-136) /13			$0.00	-	$0.00
					Appendix A Line 62		Appendix A Line 34

Note: Deductions resulting from gains or recoveries that exceed the unamortized balance are recorded in FERC Account 254, Other Regulatory Liabilities.

138	Prepayments (Account 165)	111.57.c	-	-	-

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

					Amos Substation Upgrade	Amos to Welton Spring Line	Welton Spring Substation and SVC	**Welton Spring to Interconnection with PATH Allegheny**	**Total**
139	**Calculation of Transmission CWIP**	Source							
140	December	216.b	2018	$ -	-	-	-	-	-
141	January	company records	2019	-	-	-	-	-	-
142	February	company records	2019	-	-	-	-	-	-
143	March	company records	2019	-	-	-	-	-	-
144	April	company records	2019	-	-	-	-	-	-
145	May	company records	2019	-	-	-	-	-	-
146	June	company records	2019	-	-	-	-	-	-
147	July	company records	2019	-	-	-	-	-	-
148	August	company records	2019	-	-	-	-	-	-
149	September	company records	2019	-	-	-	-	-	-
150	October	company records	2019	-	-	-	-	-	-
151	November	company records	2019	-	-	-	-	-	-
152	December	216.b	2019	-	-	-	-	-	-
153	**Transmission CWIP**	(sum lines 140-152) /13		-	-	-	-	-	-

LAND HELD FOR FUTURE USE

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	Average	Details
154	**LAND HELD FOR FUTURE USE**	p214	Total	-	-	-	
			Non-transmission Related	-	-		
			Transmission Related	-	-	-	

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
	Allocated General & Common Expenses					
		EPRI Dues	Common Expenses	EPRI Dues	Common Expenses	
155	EPRI Dues & Common Expenses	p352-353	p356	-	-	

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G					
156	Regulatory Commission Exp Account 928	p323.189.b	-	-	-	

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

Safety Related Advertising, Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Safety, Education, Siting & Outreach Related	Other	Details
	Directly Assigned A&G					
157	General Advertising Exp Account 930.1	p323.191.b	-	-	-	None

Multi-state Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Weighed Average
	Income Tax Rates						
			WV				
158	SIT=State Income Tax Rate or Composite		6.490%				6.49%

Excluded Plant Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
159	Excluded Transmission Facilities		-	**General Description of the Facilities**
	Instructions:		**Enter $**	**None**
1	Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service.		-	
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	**Example**	**Or Enter $**	
A	Total investment in substation	1,000,000	-	
B	Identifiable investment in Transmission (provide workpapers)	500,000	-	
C	Identifiable investment in Distribution (provide workpapers)	400,000	-	
D	Amount to be excluded (A x (C / (B + C)))	444,444	-	
				Add more lines if necessary

Materials & Supplies

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year	Average
160	Assigned to O&M	p227.6	-	-	-
161	Stores Expense Undistributed	p227.16	-	-	-
162	Undistributed Stores Exp		-	-	-
163	Transmission Materials & Supplies	p227.8	-	-	-

Regulatory Asset

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
				Reference FERC Form 1 page 232 for details.
164	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	-	Uncapitalized costs as of date the rates become effective
165	Months Remaining in Amortization Period		-	As approved by FERC
166	Monthly Amortization	(line 164 - line 168) / 167	-	
167	Months in Year to be amortized		-	Number of months rates are in effect during the calendar year
168	Ending Balance of Regulatory Asset	p111.72.c	-	
169	Average Balance of Regulatory Asset	(line 164 + line 168)/2	-	

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

Capital Structure

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

		Year	Debt	Preferred Stock	Common Stock
170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2019	0	-	0
173	February	2019	-	-	-
174	March	2019	-	-	-
175	April	2019	-	-	-
176	May	2019	-	-	-
177	June	2019	-	-	-
178	July	2019	-	-	-
179	August	2019	-	-	-
180	September	2019	-	-	-
181	October	2019	-	-	-
182	November	2019	-	-	-
183	December	2019	-	-	-
184	Average		0	-	0

Note: the amount outstanding for debt retired during the year is the outstanding amount as of the last month it was outstanding; the equity is less Account 216.1, Preferred Stock, and Account 219; and the capital structure is fixed at 50/50 until the first two lines are placed in service

Detail of Account 566 Miscellaneous Transmission Expenses

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

			Total
185	Amortization Expense on Regulatory Asset		-
186	Miscellaneous Transmission Expense		-
187	Total Account 566	Footnote Data: Schedule Page 320 b. 97	-

PBOPs

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions — **Details**

188	**Calculation of PBOP Expenses**		
189	**PATH-WV - AEP Employees**		
190	Total PBOP expenses		$117,254,159
191	Amount relating to retired personnel		$0
192	Amount allocated on Labor		$117,254,159
193	Labor dollars		1,151,954,661
194	Cost per labor dollar		$0.102
195	PATH WV labor (labor not capitalized) current year		103,840
196	PATH WV PBOP Expense for current year		$10,570
197	PATH WV PBOP Expense in Account 926 for current year		-$3,125
198	PBOP Adjustment for Appendix A, Line 50		$13,695
199	Lines 190-194 cannot change absent approval or acceptance by FERC in a separate proceeding.		
199	**PATH-WV - Allegheny Employees**		
200	Total PBOP expenses		$22,856,433
201	Amount relating to retired personnel		$8,786,372
202	Amount allocated on FTEs		$14,070,061
203	Number of FTEs		4,474
204	Cost per FTE		$3,145
205	PATH WV FTEs (labor not capitalized) current year		-
206	PATH WV PBOP Expense for current year		$0
207	PATH WV PBOP Expense in Account 926 for current year		$0
208	PBOP Adjustment for Appendix A, Line 50		$0
209	Lines 200-204 cannot change absent approval or acceptance by FERC in a separate proceeding.		
210	PBOP Expense adjustment	(sum lines 198 & 208)	$13,695

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

Plant in Service Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

1	**Calculation of Transmission Plant In Service**	Source	Year	Balance
2	December	p206.58.b	2018	-
3	January	company records	2019	-
4	February	company records	2019	-
5	March	company records	2019	-
6	April	company records	2019	-
7	May	company records	2019	-
8	June	company records	2019	-
9	July	company records	2019	-
10	August	company records	2019	-
11	September	company records	2019	-
12	October	company records	2019	-
13	November	company records	2019	-
14	December	p207.58.g	2019	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2018	-
18	January	company records	2019	-
19	February	company records	2019	-
20	March	company records	2019	-
21	April	company records	2019	-
22	May	company records	2019	-
23	June	company records	2019	-
24	July	company records	2019	-
25	August	company records	2019	-
26	September	company records	2019	-
27	October	company records	2019	-
28	November	company records	2019	-
29	December	p207.75.g	2019	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5b	2018	-
33	December	p205.5.g	2019	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2018	-
37	December	p207.99.g	2019	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2018	-
41	January	company records	2019	-
42	February	company records	2019	-
43	March	company records	2019	-
44	April	company records	2019	-
45	May	company records	2019	-
46	March	Attachment 6	2019	-
47	April	company records	2019	-
48	August	company records	2019	-
49	September	company records	2019	-
50	October	company records	2019	-
51	November	company records	2019	-
52	December	p205.46.g	2019	-
53	**Production Plant In Service**	(sum lines 40-52) /13		-

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

54	**Calculation of Common Plant In Service**	Source	Year	Balance
55	December (Electric Portion)	p356	2018	-
56	December (Electric Portion)	p356	2019	-
57	**Common Plant In Service**	(sum lines 55 & 56) /2		-
58	**Total Plant In Service**	(sum lines 15, 30, 34, 38, 53, & 57)		-

Accumulated Depreciation Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
59	**Calculation of Transmission Accumulated Depreciation**	Source	Year	Balance	
60	December	Prior year p219.25	2018	-	
61	January	company records	2019	-	
62	February	company records	2019	-	
63	March	company records	2019	-	
64	April	company records	2019	-	
65	May	company records	2019	-	
66	June	company records	2019	-	
67	July	company records	2019	-	
68	August	company records	2019	-	
69	September	company records	2019	-	
70	October	company records	2019	-	
71	November	company records	2019	-	
72	December	p219.25	2019	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2018	-	
76	January	company records	2019	-	
77	February	company records	2019	-	
78	March	company records	2019	-	
79	April	company records	2019	-	
80	May	company records	2019	-	
81	June	company records	2019	-	
82	July	company records	2019	-	
83	August	company records	2019	-	
84	September	company records	2019	-	
85	October	company records	2019	-	
86	November	company records	2019	-	
87	December	p219.26	2019	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2018	-	
91	December	p200.21c	2019	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2018	-	
95	December	p219.28	2019	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2018	-
99	January	company records	2019	-
100	February	company records	2019	-
101	March	company records	2019	-
102	April	company records	2019	-
103	May	company records	2019	-
104	June	company records	2019	-
105	July	company records	2019	-
106	August	company records	2019	-
107	September	company records	2019	-
108	October	company records	2019	-
109	November	company records	2019	-
110	December	p219.20 thru 219.24	2019	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2018	-
114	December (Electric Portion)	p356	2019	-
115	**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-
116	**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		-

ADJUSTMENTS TO RATE BASE (Note A)

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				**Details**
			Beginning of Year	End of Year	Average Balance
117	Account No. 281 (enter negative)	273.8.k	-	-	-
118	Account No. 282 (enter negative)	275.2.k	-	-	-
119	Account No. 283 (enter negative)	277.9.k	-	-	-
120	Account No. 190	234.8.c	1,341,425	566,166	953,796
121	Account No. 255 (enter negative)	267.8.h	-	-	-

122	**Unamortized Abandoned Plant**	Per FERC Order					
123	**Monthly Balance**	Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
124	December	p111.71.d (and Notes)	0				
125	January	company records		-	-	-	-
126	February	company records		-	-	-	-
127	March	company records		-	-	-	-
128	April	company records		-	-	-	-
129	May	company records		-	-	-	-
130	June	company records		-	-	-	-
131	July	company records		-	-	-	-
132	August	company records		-	-	-	-
133	September	company records		-	-	-	-
134	October	company records		-	-	-	-
135	November	company records		-	-	-	-
136	December	p111.71.c (and Notes) Detail on p230b		-	-	-	-
137	**Ending Balance is a 13-Month Average**	(sum lines 124-136) /13			$0.00 Appendix A Line 62	-	$0.00 Appendix A Line 34

Note: Deductions resulting from gains or recoveries that exceed the unamortized balance are recorded in FERC Account 254, Other Regulatory Liabilities.

138	Prepayments (Account 165)	111.57.c	-	-	-

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

139	**Calculation of Transmission CWIP**	Source				**Kemptown Substation**	**Kemptown to Interconnection with PATH West Virginia**	**Welton Spring Substation and SVC**	**Total**
140	December	216.b	2018	$	-				
141	January	company records	2019		-				
142	February	company records	2019		-				
143	March	company records	2019		-				
144	April	company records	2019		-				
145	May	company records	2019		-				
146	June	company records	2019		-				
147	July	company records	2019		-				
148	August	company records	2019		-				
149	September	company records	2019		-				
150	October	company records	2019		-				
151	November	company records	2019		-				
152	December	216.b	2019		-				
153	**Transmission CWIP**	(sum lines 140-152) /13			-	-	-	-	-

LAND HELD FOR FUTURE USE

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	Average	Details
154	**LAND HELD FOR FUTURE USE**	p214	Total	-	-	-	
			Non-transmission Related	-	-		
			Transmission Related	-	-	-	

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
	Allocated General & Common Expenses	EPRI Dues	Common Expenses	EPRI Dues	Common Expenses	
155	EPRI Dues & Common Expenses	p352-353	p356	-	-	

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G					
156	Regulatory Commission Exp Account 928	p323.189.b	-	-	-	

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

Safety Related Advertising, Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Safety, Education, Siting & Outreach Related	Other	Details
	Directly Assigned A&G					
157	General Advertising Exp Account 930.1	p323.191.b	-	-	-	None

Multi-state Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Weighed Average
	Income Tax Rates						
		MD	WV	VA			
158	SIT=State Income Tax Rate or Composite	8.250%	6.500%	6.000%			3.286%

Excluded Plant Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
159	Excluded Transmission Facilities		-	**General Description of the Facilities**
	Instructions:		**Enter $**	**None**
1	Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service.		-	
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	**Example**	**Or** **Enter $**	
A	Total investment in substation	1,000,000	-	
B	Identifiable investment in Transmission (provide workpapers)	500,000	-	
C	Identifiable investment in Distribution (provide workpapers)	400,000	-	
D	Amount to be excluded (A x (C / (B + C)))	444,444	-	
				Add more lines if necessary

Materials & Supplies

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year	Average
160	Assigned to O&M	p227.6	-	-	-
161	Stores Expense Undistributed	p227.16	-	-	-
162	Undistributed Stores Exp		-	-	-
163	Transmission Materials & Supplies	p227.8	-	-	-

Regulatory Asset

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
				Reference FERC Form 1 page 232 for details.
164	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	-	Uncapitalized costs as of date the rates become effective
165	Months Remaining in Amortization Period		-	As approved by FERC
166	Monthly Amortization	(line 164 - line 168) / 167	-	
167	Months in Year to be Amortized		-	Number of months rates are in effect during the calendar year
168	Ending Balance of Regulatory Asset	p111.72.c	-	
169	Average Balance of Regulatory Asset	(line 164 + line 168)/2	-	

Attachment 4 - Cost Support
Ba

Capital Structure

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2019	0	-	0
173	February	2019	-	-	-
174	March	2019	-	-	-
175	April	2019	-	-	-
176	May	2019	-	-	-
177	June	2019	-	-	-
178	July	2019	-	-	-
179	August	2019	-	-	-
180	September	2019	-	-	-
181	October	2019	-	-	-
182	November	2019	-	-	-
183	December	2019	-	-	-
184	Average		0	-	0

Note: the amount outstanding for debt retired during the year is the outstanding amount as of the last month it was outstanding; the equity is less Account 216.1, Preferred Stock, and Account 219; and the capital structure is fixed at 50/50 until the first two lines are placed in service

Detail of Account 566 Miscellaneous Transmission Expenses

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

			Total
185	Amortization Expense on Regulatory Asset		-
186	Miscellaneous Transmission Expense		59,523
187	Total Account 566	Footnote Data: Schedule Page 320 b. 97	59,523

PBOPs

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Details
188	**Calculation of PBOP Expenses**		
189	**PATH - Allegheny - Allegheny Employees**		
190	Total PBOP expenses	$22,856,433	
191	Amount relating to retired personnel	$8,786,372	
192	Amount allocated on FTEs	$14,070,061	
193	Number of FTEs	4,475	
194	Cost per FTE	$3,144	
195	PATH Allegheny FTEs (labor not capitalized) current year	-	
196	PATH Allegheny PBOP Expense for current year	$0	
197	PATH Allegheny PBOP Expense in Account 926 for current year	$0	
198	PBOP Adjustment for Appendix A, Line 50	-	
199	Lines 190-194 cannot change absent approval or acceptance by FERC in a separate proceeding.		

Attachment 5 - Transmission Enhancement Charge Worksheet
PATH West Virginia Transmission Company, LLC

1 New Plant Carrying Charge

Line	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	2,178,888
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	-
6	34	Unamortized Abandoned Plant	-
7		**Carrying charge (line 3/sum of lines 4, 5 and 6)**	**-**

8 **The FCR resulting from Formula in a given year is used for that year only.**

9 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

				(1)	(2)	(3)	(4)	(5)	(6)
				PJM Upgrade ID: b0490 & b0491					
10		Details		Amos Substation Upgrade - CWIP	Amos to Midpoint Line - CWIP	Midpoint Substation and SVC - CWIP	**Midpoint to Interconnection with PATH Allegheny - CWIP**	Transmission Plant In Service	Unamortized Abandoned Plant
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes		Yes	Yes
12		FCR for This Project		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	Forecast – Forecast of average 13 month current year net transmission plant plus 13-mo CWIP balances. Reconciliation – Average of 13 month prior year net transmission plant balances plus prior year 13-mo CWIP balances.	Investment		0	-	-	-	-	-
		Revenue Requirement		-	-	-	-	-	-

(7) Totals
-
2,178,888

Attachment 5 - Transmission Enhancement Charge Worksheet
PATH Allegheny Transmission Company, LLC

1 New Plant Carrying Charge

Line	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	1,573,733
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	-
6	34	Unamortized Abandoned Plant	-
7		**Carrying charge (line 3/sum of lines 4, 5and 6)**	**-**

8 **The FCR resulting from Formula in a given year is used for that year only.**

9 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

				(1)	(2)	(3)	(4)	(5)	(6)
				PJM Upgrade ID: b0492 & b0560					
10		Details		Kemptown Substation - CWIP	Kemptown to Interconnection with PATH West Virginia - CWIP	Welton Spring Substation and SVC - CWIP	Transmission Plant In Service	Unamortized Abandoned Plant	Totals
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes	Yes	
12		FCR for This Project		0.0%	0.0%	0.0%	0.0%	0.0%	
13	Forecast – Forecast of average 13 month current year net transmission plant plus 13-mo CWIP balances. Reconciliation – Average of 13 month prior year net transmission plant balances plus prior year 13-mo CWIP balances.	Investment		-	-	-	-	-	-
		Revenue Requirement		-	-	-	-	-	1,573,732.64

Attachment 6 has been removed and intentionally left blank.

Attachment 6 has been removed and intentionally left blank.

Attachment 7
PATH West Virginia Transmission Company, LLC

Potomac-Appalachian Transmission Highline, LLC

CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE

YEAR ENDED 12/31/2014

(HYPOTHETICAL EXAMPLE)

	Amount Outstanding	Unamortized Debt Issue Expense	Unamortized Debt Premium/ (Discount)	Unamortized Losses on Reacquired Debt	Net Amount Outstanding	Effective Cost Rate[1]	Annualized Cost
Debt:							
First Mortgage Bonds:							
	$ 300,000,000	$2,900,000	($2,320,000)	$0	$294,780,000	#N/A	#N/A
Other Long Term Debt:							
6.600% Series Medium Term Notes Due 2021	$ 200,000,000	$1,800,000		-	$198,200,000	#N/A	#N/A
					-		
Total Debt	$ 500,000,000	$ 4,700,000	$ (2,320,000)	$ -	$ 492,980,000	#N/A	#N/A
Check with FERC Form 1 B/S pgs 110-113	$ 185,750,000	$ (1,131,082)	$ (1,595,909)	$ 17,075,452			

Development of Effective Cost Rates:	Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance	Issuance Expense	Loss on Reacquired Debt	Net Proceeds	Net Proceeds Ratio	Coupon Rate	Effective Cost Rate	Annual Interest
First Mortgage Bonds											
7.090% Series Due 2041	1/1/2014	6/30/2044	$ 300,000,000	$ (2,400,000)	$ 3,000,000	-	$ 294,600,000	98.2000	0.07090	#N/A	$ 21,270,000
											-
Other Long Term Debt:											-
6.600% Series Medium Term Notes Due 2021	01/01/2014	06/30/2024	200,000,000		2,000,000		$ 198,000,000	99.0000	0.06600	#N/A	13,200,000
			$ 500,000,000	(2,400,000)	$ 5,000,000	-	$ 492,600,000				$ 34,470,000

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[1] The Effective Cost Rate is the Debt Cost shown on Page 5, Line 118 of Rate Formula Template.

Attachment 7
PATH Allegheny Transmission Company, LLC

Potomac-Appalachian Transmission Highline, LLC
CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE
YEAR ENDED 12/31/2014

(HYPOTHETICAL EXAMPLE)

	Amount Outstanding	Unamortized Debt Issue Expense	Unamortized Debt Premium/ (Discount)	Unamortized Losses on Reacquired Debt	Net Amount Outstanding	Effective Cost Rate[1]	Annualized Cost
Debt:							
First Mortgage Bonds:							
	$ 300,000,000	$2,900,000	($2,320,000)	$0	$294,780,000	#N/A	#N/A
Other Long Term Debt:							
6.600% Series Medium Term Notes Due 2021	$ 200,000,000	$1,800,000		-	$198,200,000	#N/A	#N/A
					-		
Total Debt	$ 500,000,000	$ 4,700,000	$ (2,320,000)	$ -	$ 492,980,000	**#N/A**	#N/A
Check with FERC Form 1 B/S pgs 110-113	$ 185,750,000	$ (1,131,082)	$ (1,595,909)	$ 17,075,452			

Development of Effective Cost Rates:

	Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance	Issuance Expense	Loss on Reacquired Debt	Net Proceeds	Net Proceeds Ratio	Coupon Rate	Effective Cost Rate	Annual Interest
First Mortgage Bonds											
7.090% Series Due 2041	1/1/2014	6/30/2044	$ 300,000,000	$ (2,400,000)	$ 3,000,000	-	$ 294,600,000	98.2000	0.07090	#N/A	$ 21,270,000
											-
Other Long Term Debt:											-
6.600% Series Medium Term Notes Due 2021	01/01/2014	06/30/2024	200,000,000		2,000,000		$ 198,000,000	99.0000	0.06600	#N/A	13,200,000
			$ 500,000,000	(2,400,000)	$ 5,000,000	-	$ 492,600,000				$ 34,470,000

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[1] The Effective Cost Rate is the Debt Cost shown on Page 10, Line 118 of Rate Formula Template.

Attachment 8
Potomac-Appalachian Transmission Highline, LLC
Interest Rates and Interest Calculations
PATH West Virginia Transmission Company, LLC

Reconciliation Revenue Requirement For Year 2017 Available June 1, 2018		2017 Revenue Requirement Forecast by Sept 1, 2016		True-up Adjustment - Over (Under) Recovery
$10,785,973	-	$9,524,155	=	($1,261,818)

		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Interest Rate on Amount of Refunds or Surcharges from 35.19a			0.3420%				
An over or under collection will be recovered prorata over 2017, held for 2018 and returned prorate over 2019							
Calculation of Interest					Monthly		
January	Year 2017	(105,152)	0.3420%	12	4,315		109,467
February	Year 2017	(105,152)	0.3420%	11	3,956		109,107
March	Year 2017	(105,152)	0.3420%	10	3,596		108,748
April	Year 2017	(105,152)	0.3420%	9	3,237		108,388
May	Year 2017	(105,152)	0.3420%	8	2,877		108,028
June	Year 2017	(105,152)	0.3420%	7	2,517		107,669
July	Year 2017	(105,152)	0.3420%	6	2,158		107,309
August	Year 2017	(105,152)	0.3420%	5	1,798		106,950
September	Year 2017	(105,152)	0.3420%	4	1,438		106,590
October	Year 2017	(105,152)	0.3420%	3	1,079		106,230
November	Year 2017	(105,152)	0.3420%	2	719		105,871
December	Year 2017	(105,152)	0.3420%	1	360		105,511
					28,050		1,289,868
					Annual		
January through December	Year 2018	1,289,868	0.3420%	12	52,936		1,342,804
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2019	(1,342,804)	0.3420%		4,592	(114,403)	1,232,993
February	Year 2019	(1,232,993)	0.3420%		4,217	(114,403)	1,122,807
March	Year 2019	(1,122,807)	0.3420%		3,840	(114,403)	1,012,243
April	Year 2019	(1,012,243)	0.3420%		3,462	(114,403)	901,302
May	Year 2019	(901,302)	0.3420%		3,082	(114,403)	789,981
June	Year 2019	(789,981)	0.3420%		2,702	(114,403)	678,279
July	Year 2019	(678,279)	0.3420%		2,320	(114,403)	566,195
August	Year 2019	(566,195)	0.3420%		1,936	(114,403)	453,728
September	Year 2019	(453,728)	0.3420%		1,552	(114,403)	340,876
October	Year 2019	(340,876)	0.3420%		1,166	(114,403)	227,639
November	Year 2019	(227,639)	0.3420%		779	(114,403)	114,014
December	Year 2019	(114,014)	0.3420%		390	(114,403)	0
					30,037		
True-Up Adjustment with Interest*						1,372,842	
Less Over (Under) Recovery						(1,261,818)	
Total Interest						111,024	

*This amount plus Account 190 correction relating to a federal NOL carryforward (see Workpaper 1) corresponds to PATH-WV Attachment A, Line 3

Attachment 8
Potomac-Appalachian Transmission Highline, LLC
Example of Interest Rates and Interest Calculations
PATH Allegheny Transmission Company, LLC

Reconciliation Revenue Requirement For Year 2017 Available June 1, 2018		2017 Revenue Requirement Forecast by Sept 1, 2016		True-up Adjustment - Over (Under) Recovery
$10,430,003	-	$9,187,747	=	($1,242,256)

		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Interest Rate on Amount of Refunds or Surcharges from 35.19a			0.3420%				
An over or under collection will be recovered prorata over 2017, held for 2018 and returned prorate over 2019							
Calculation of Interest					Monthly		
January	Year 2017	(103,521)	0.3420%	12	4,249		107,770
February	Year 2017	(103,521)	0.3420%	11	3,894		107,416
March	Year 2017	(103,521)	0.3420%	10	3,540		107,062
April	Year 2017	(103,521)	0.3420%	9	3,186		106,708
May	Year 2017	(103,521)	0.3420%	8	2,832		106,354
June	Year 2017	(103,521)	0.3420%	7	2,478		106,000
July	Year 2017	(103,521)	0.3420%	6	2,124		105,646
August	Year 2017	(103,521)	0.3420%	5	1,770		105,292
September	Year 2017	(103,521)	0.3420%	4	1,416		104,938
October	Year 2017	(103,521)	0.3420%	3	1,062		104,583
November	Year 2017	(103,521)	0.3420%	2	708		104,229
December	Year 2017	(103,521)	0.3420%	1	354		103,875
					27,615		1,269,871
					Annual		
January through December	Year 2018	1,269,871	0.3420%	12	52,116		1,321,987
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2019	(1,321,987)	0.3420%		4,521	(112,630)	1,213,878
February	Year 2019	(1,213,878)	0.3420%		4,151	(112,630)	1,105,400
March	Year 2019	(1,105,400)	0.3420%		3,780	(112,630)	996,550
April	Year 2019	(996,550)	0.3420%		3,408	(112,630)	887,329
May	Year 2019	(887,329)	0.3420%		3,035	(112,630)	777,733
June	Year 2019	(777,733)	0.3420%		2,660	(112,630)	667,763
July	Year 2019	(667,763)	0.3420%		2,284	(112,630)	557,417
August	Year 2019	(557,417)	0.3420%		1,906	(112,630)	446,694
September	Year 2019	(446,694)	0.3420%		1,528	(112,630)	335,592
October	Year 2019	(335,592)	0.3420%		1,148	(112,630)	224,109
November	Year 2019	(224,109)	0.3420%		766	(112,630)	112,246
December	Year 2019	(112,246)	0.3420%		384	(112,630)	(0)
					29,572		

True-Up Adjustment with Interest	$	1,351,559
Less Over (Under) Recovery	$	(1,242,256)
Total Interest	$	109,303

Potomac-Appalachian Transmission Highline, LLC
Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Applicable to both PATH West Virginia Transmission Company, LLC & PATH Allegheny Transmission Company, LLC

To be Prepared on 8/15/2013 (hypothetical date)

SUMMARY

			Hypothetical Revenue Requirement				
YEAR	**Estimated Effective cost of debt used in forecast/true up**	**Final Effective cost of debt for the construction loan:**	**Based on Estimated Effective cost of debt**	**Based on Actual Effective cost of debt**	Over (Under) Recovery	**Hypothetical Monthly Interest Rate applicable over the ATRR period**	Total Amount of Construction Loan Related True-Up included in rates effective Jan 2014 (Refund)/Owed
2008	7.18%	7.00%	$ 2,500,000.00	$ 2,400,000.00	$ 100,000.00	0.550%	$ (148,288.33)
2009	6.8%	7.00%	$5,000,000.00	$5,150,000.00	$ (150,000.00)	0.560%	$ 209,670.43
2010	7.2%	7.00%	$8,300,000.00	$8,200,000.00	$ 100,000.00	0.540%	$ (131,109.09)
2011	7.3%	7.00%	$12,300,000.00	$12,000,000.00	$ 300,000.00	0.580%	$ (368,656.73)
2012*	7.1%	6.83%	$18,000,000.00	$17,900,000.00	$ 100,000.00	0.570%	$ (114,946.28)
2013**	6.50%	6.50%	$25,000,000.00	$25,000,000.00	$ -		
2014**	6.50%	6.50%					$ (553,329.99)

**** Assumes that the construction loan is retired on Sept 1, 2012***

***** Assumes permanent debt structure is put in place on Sept 1, 2012 with effective rate of 6.5%***

Note: True-Up period is 2008 - 2012, with the true-up amount included in 2014 forecasted ATRR. Final effective cost of debt for 2012 is computed as follows: ((7%*243days)+(6.5%*122days))/365days

Calculation of Applicable Interest Expense for each ATRR period

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Hypothetical Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
<u>Calculation of Interest for 2008 True-Up Period</u>							
An over or under collection will be recovered prorata over 2008, held for 2009, 2010, 2011, 2012, 2013 and returned prorate over 2014					Monthly		
January	Year 2008	-	0.5500%	12.00	-		-
February	Year 2008	-	0.5500%	11.00	-		-
March	Year 2008	10,000	0.5500%	10.00	(550)		(10,550)
April	Year 2008	10,000	0.5500%	9.00	(495)		(10,495)
May	Year 2008	10,000	0.5500%	8.00	(440)		(10,440)
June	Year 2008	10,000	0.5500%	7.00	(385)		(10,385)
July	Year 2008	10,000	0.5500%	6.00	(330)		(10,330)
August	Year 2008	10,000	0.5500%	5.00	(275)		(10,275)
September	Year 2008	10,000	0.5500%	4.00	(220)		(10,220)
October	Year 2008	10,000	0.5500%	3.00	(165)		(10,165)
November	Year 2008	10,000	0.5500%	2.00	(110)		(10,110)
December	Year 2008	10,000	0.5500%	1.00	(55)		(10,055)
					(3,025)		(103,025)
					Annual		
January through December	Year 2009	(103,025)	0.5600%	12.00	(6,923)		(109,948)
January through December	Year 2010	(109,948)	0.5400%	12.00	(7,125)		(117,073)
January through December	Year 2011	(117,073)	0.5800%	12.00	(8,148)		(125,221)
January through December	Year 2012	(125,221)	0.5700%	12.00	(8,565)		(133,786)
January through December	Year 2013	(133,786)	0.5700%	12.00	(9,151)		(142,937)
<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>					Monthly		
January	Year 2014	142,937	0.5700%		(815)	(12,357)	(131,395)
February	Year 2014	131,395	0.5700%		(749)	(12,357)	(119,786)
March	Year 2014	119,786	0.5700%		(683)	(12,357)	(108,112)
April	Year 2014	108,112	0.5700%		(616)	(12,357)	(96,371)
May	Year 2014	96,371	0.5700%		(549)	(12,357)	(84,563)
June	Year 2014	84,563	0.5700%		(482)	(12,357)	(72,687)
July	Year 2014	72,687	0.5700%		(414)	(12,357)	(60,744)
August	Year 2014	60,744	0.5700%		(346)	(12,357)	(48,733)
September	Year 2014	48,733	0.5700%		(278)	(12,357)	(36,653)
October	Year 2014	36,653	0.5700%		(209)	(12,357)	(24,505)
November	Year 2014	24,505	0.5700%		(140)	(12,357)	(12,287)
December	Year 2014	12,287	0.5700%		(70)	(12,357)	0
					(5,351)		
Total Amount of True-Up Adjustment for 2008 ATRR						$ (148,288)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (48,288)	

Potomac-Appalachian Transmission Highline, LLC
Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Applicable to both PATH West Virginia Transmission Company, LLC & PATH Allegheny Transmission Company, LLC

Calculation of Interest for 2009 True-Up Period

An over or under collection will be recovered prorata over 2009, held for 2010, 2011, 2012, 2013 and returned prorate over 2014					Monthly		
January	Year 2009	(12,500)	0.5600%	12.00	840		13,340
February	Year 2009	(12,500)	0.5600%	11.00	770		13,270
March	Year 2009	(12,500)	0.5600%	10.00	700		13,200
April	Year 2009	(12,500)	0.5600%	9.00	630		13,130
May	Year 2009	(12,500)	0.5600%	8.00	560		13,060
June	Year 2009	(12,500)	0.5600%	7.00	490		12,990
July	Year 2009	(12,500)	0.5600%	6.00	420		12,920
August	Year 2009	(12,500)	0.5600%	5.00	350		12,850
September	Year 2009	(12,500)	0.5600%	4.00	280		12,780
October	Year 2009	(12,500)	0.5600%	3.00	210		12,710
November	Year 2009	(12,500)	0.5600%	2.00	140		12,640
December	Year 2009	(12,500)	0.5600%	1.00	70		12,570
					5,460		155,460
					Annual		
January through December	Year 2010	155,460	0.5400%	12.00	10,074		165,534
January through December	Year 2011	165,534	0.5800%	12.00	11,521		177,055
January through December	Year 2012	177,055	0.5700%	12.00	12,111		189,166
January through December	Year 2013	189,166	0.5700%	12.00	12,939		202,104
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2014	(202,104)	0.5700%		1,152	17,473	185,784
February	Year 2014	(185,784)	0.5700%		1,059	17,473	169,370
March	Year 2014	(169,370)	0.5700%		965	17,473	152,863
April	Year 2014	(152,863)	0.5700%		871	17,473	136,262
May	Year 2014	(136,262)	0.5700%		777	17,473	119,566
June	Year 2014	(119,566)	0.5700%		682	17,473	102,775
July	Year 2014	(102,775)	0.5700%		586	17,473	85,888
August	Year 2014	(85,888)	0.5700%		490	17,473	68,905
September	Year 2014	(68,905)	0.5700%		393	17,473	51,826
October	Year 2014	(51,826)	0.5700%		295	17,473	34,649
November	Year 2014	(34,649)	0.5700%		197	17,473	17,374
December	Year 2014	(17,374)	0.5700%		99	17,473	(0)
					7,566		
Total Amount of True-Up Adjustment for 2009 ATRR						$ 209,670	
Less Over (Under) Recovery						$ (150,000)	
Total Interest						$ 59,670	

Calculation of Interest for 2010 True-Up Period

An over or under collection will be recovered prorata over 2010, held for 2011, 2012, 2013 and returned prorate over 2014					Monthly		
January	Year 2010	8,333	0.5400%	12.00	(540)		(8,873)
February	Year 2010	8,333	0.5400%	11.00	(495)		(8,828)
March	Year 2010	8,333	0.5400%	10.00	(450)		(8,783)
April	Year 2010	8,333	0.5400%	9.00	(405)		(8,738)
May	Year 2010	8,333	0.5400%	8.00	(360)		(8,693)
June	Year 2010	8,333	0.5400%	7.00	(315)		(8,648)
July	Year 2010	8,333	0.5400%	6.00	(270)		(8,603)
August	Year 2010	8,333	0.5400%	5.00	(225)		(8,558)
September	Year 2010	8,333	0.5400%	4.00	(180)		(8,513)
October	Year 2010	8,333	0.5400%	3.00	(135)		(8,468)
November	Year 2010	8,333	0.5400%	2.00	(90)		(8,423)
December	Year 2010	8,333	0.5400%	1.00	(45)		(8,378)
					(3,510)		(103,510)
					Annual		
January through December	Year 2011	(103,510)	0.5800%	12.00	(7,204)		(110,714)
January through December	Year 2012	(110,714)	0.5700%	12.00	(7,573)		(118,287)
January through December	Year 2013	(118,287)	0.5700%	12.00	(8,091)		(126,378)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2014	126,378	0.5700%		(720)	(10,926)	(116,173)
February	Year 2014	116,173	0.5700%		(662)	(10,926)	(105,909)
March	Year 2014	105,909	0.5700%		(604)	(10,926)	(95,587)
April	Year 2014	95,587	0.5700%		(545)	(10,926)	(85,206)
May	Year 2014	85,206	0.5700%		(486)	(10,926)	(74,766)
June	Year 2014	74,766	0.5700%		(426)	(10,926)	(64,266)
July	Year 2014	64,266	0.5700%		(366)	(10,926)	(53,707)
August	Year 2014	53,707	0.5700%		(306)	(10,926)	(43,087)
September	Year 2014	43,087	0.5700%		(246)	(10,926)	(32,407)
October	Year 2014	32,407	0.5700%		(185)	(10,926)	(21,666)
November	Year 2014	21,666	0.5700%		(123)	(10,926)	(10,864)
December	Year 2014	10,864	0.5700%		(62)	(10,926)	0
					(4,731)		
Total Amount of True-Up Adjustment for 2010 ATRR						$ (131,109)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (31,109)	

Potomac-Appalachian Transmission Highline, LLC
Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Applicable to both PATH West Virginia Transmission Company, LLC & PATH Allegheny Transmission Company, LLC

Calculation of Interest for 2011 True-Up Period							
An over or under collection will be recovered prorata over 2011, held for 2012, 2013 and returned prorate over 2014					Monthly		
January	Year 2011	25,000	0.5800%	12.00	(1,740)		(26,740)
February	Year 2011	25,000	0.5800%	11.00	(1,595)		(26,595)
March	Year 2011	25,000	0.5800%	10.00	(1,450)		(26,450)
April	Year 2011	25,000	0.5800%	9.00	(1,305)		(26,305)
May	Year 2011	25,000	0.5800%	8.00	(1,160)		(26,160)
June	Year 2011	25,000	0.5800%	7.00	(1,015)		(26,015)
July	Year 2011	25,000	0.5800%	6.00	(870)		(25,870)
August	Year 2011	25,000	0.5800%	5.00	(725)		(25,725)
September	Year 2011	25,000	0.5800%	4.00	(580)		(25,580)
October	Year 2011	25,000	0.5800%	3.00	(435)		(25,435)
November	Year 2011	25,000	0.5800%	2.00	(290)		(25,290)
December	Year 2011	25,000	0.5800%	1.00	(145)		(25,145)
					(11,310)		(311,310)
					Annual		
January through December	Year 2012	(311,310)	0.5700%	12.00	(21,294)		(332,604)
January through December	Year 2013	(332,604)	0.5700%	12.00	(22,750)		(355,354)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2014	355,354	0.5700%		(2,026)	(30,721)	(326,658)
February	Year 2014	326,658	0.5700%		(1,862)	(30,721)	(297,798)
March	Year 2014	297,798	0.5700%		(1,697)	(30,721)	(268,774)
April	Year 2014	268,774	0.5700%		(1,532)	(30,721)	(239,585)
May	Year 2014	239,585	0.5700%		(1,366)	(30,721)	(210,229)
June	Year 2014	210,229	0.5700%		(1,198)	(30,721)	(180,706)
July	Year 2014	180,706	0.5700%		(1,030)	(30,721)	(151,015)
August	Year 2014	151,015	0.5700%		(861)	(30,721)	(121,154)
September	Year 2014	121,154	0.5700%		(691)	(30,721)	(91,123)
October	Year 2014	91,123	0.5700%		(519)	(30,721)	(60,921)
November	Year 2014	60,921	0.5700%		(347)	(30,721)	(30,547)
December	Year 2014	30,547	0.5700%		(174)	(30,721)	0
					(13,303)		
Total Amount of True-Up Adjustment for 2011 ATRR						$ (368,657)	
Less Over (Under) Recovery						$ 300,000	
Total Interest						$ (68,657)	

Calculation of Interest for 2012 True-Up Period							
An over or under collection will be recovered prorata over 2012, held for 2013 and returned prorate over 2014					Monthly		
January	Year 2012	8,333	0.5700%	12.00	(570)		(8,903)
February	Year 2012	8,333	0.5700%	11.00	(523)		(8,856)
March	Year 2012	8,333	0.5700%	10.00	(475)		(8,808)
April	Year 2012	8,333	0.5700%	9.00	(428)		(8,761)
May	Year 2012	8,333	0.5700%	8.00	(380)		(8,713)
June	Year 2012	8,333	0.5700%	7.00	(333)		(8,666)
July	Year 2012	8,333	0.5700%	6.00	(285)		(8,618)
August	Year 2012	8,333	0.5700%	5.00	(238)		(8,571)
September	Year 2012	8,333	0.5700%	4.00	(190)		(8,523)
October	Year 2012	8,333	0.5700%	3.00	(143)		(8,476)
November	Year 2012	8,333	0.5700%	2.00	(95)		(8,428)
December	Year 2012	8,333	0.5700%	1.00	(48)		(8,381)
					(3,705)		(103,705)
					Annual		
January through December	Year 2013	(103,705)	0.5700%	12.00	(7,093)		(110,798)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2014	110,798	0.5700%		(632)	(9,579)	(101,851)
February	Year 2014	101,851	0.5700%		(581)	(9,579)	(92,853)
March	Year 2014	92,853	0.5700%		(529)	(9,579)	(83,803)
April	Year 2014	83,803	0.5700%		(478)	(9,579)	(74,702)
May	Year 2014	74,702	0.5700%		(426)	(9,579)	(65,549)
June	Year 2014	65,549	0.5700%		(374)	(9,579)	(56,344)
July	Year 2014	56,344	0.5700%		(321)	(9,579)	(47,086)
August	Year 2014	47,086	0.5700%		(268)	(9,579)	(37,776)
September	Year 2014	37,776	0.5700%		(215)	(9,579)	(28,412)
October	Year 2014	28,412	0.5700%		(162)	(9,579)	(18,995)
November	Year 2014	18,995	0.5700%		(108)	(9,579)	(9,525)
December	Year 2014	9,525	0.5700%		(54)	(9,579)	0
					(4,148)		
Total Amount of True-Up Adjustment for 2012 ATRR						$ (114,946)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (14,946)	

Potomac-Appalachian Transmission Highline, LLC
Attachment 10 - Depreciation Accrual Rates

Applicable to PATH West Virginia Transmission Company, LLC

TRANSMISSION PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
350.2	Land & Land Rights - Easements	1.43	-
352	Structures & Improvements	1.82	-
353	Station Equipment		
	Other	2.43	-
	SVC Dynamic Control Equipment	4.09	-
354	Towers & Fixtures	1.26	-
355	Poles & Fixtures	3.11	-
356	Overhead Conductors & Devices	1.13	-
Total Transmission Plant Depreciation			-
Total Transmission Depreciation Expense (must tie to p336.7.b & c)	-		

GENERAL PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
390	Structures & Improvements	2.00	-
391	Office Furniture & Equipment	5.00	-
	Information Systems	10.00	-
	Data Handling	10.00	
392	Transportation Equipment		
	Other	5.33	-
	Autos	11.43	-
	Light Trucks	6.96	-
	Medium Trucks	6.96	-
	Trailers	4.44	-
	ATV	5.33	-
393	Stores Equipment	5.00	-
394	Tools, Shop & Garage Equipment	5.00	-
395	Laboratory Equipment	5.00	-
396	Power Operated Equipment	4.17	-
397	Communication Equipment	6.67	-
398	Miscellaneous Equipment	6.67	-
Total General Plant			-
Total General Plant Depreciation Expense (must tie to p336.10.b & c)	-		

INTANGIBLE PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
303	Miscellaneous Intangible Plant	20.00	-
Total Intangible Plant			-
Total Intangible Plant Amortization (must tie to p336.1 d & e)	-		

These depreciation rates will not change absent the appropriate filing at FERC.

Potomac-Appalachian Transmission Highline, LLC
Attachment 10 - Depreciation Accrual Rates

Applicable to PATH Allegheny Transmission Company, LLC

TRANSMISSION PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
350.2	Land & Land Rights - Easements	1.43	-
352	Structures & Improvements	1.82	-
353	Station Equipment		
	Other	2.43	-
	SVC Dynamic Control Equipment	4.09	-
354	Towers & Fixtures	1.26	-
355	Poles & Fixtures	3.11	-
356	Overhead Conductors & Devices	1.13	-
Total Transmission Plant Depreciation			-
Total Transmission Depreciation Expense (must tie to p336.7.b & c)	-		

GENERAL PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
390	Structures & Improvements	2.00	-
391	Office Furniture & Equipment	5.00	-
	Information Systems	10.00	-
	Data Handling	10.00	
392	Transportation Equipment		
	Other	5.33	-
	Autos	11.43	-
	Light Trucks	6.96	-
	Medium Trucks	6.96	-
	Trailers	4.44	-
	ATV	5.33	-
393	Stores Equipment	5.00	-
394	Tools, Shop & Garage Equipment	5.00	-
395	Laboratory Equipment	5.00	-
396	Power Operated Equipment	4.17	-
397	Communication Equipment	6.67	-
398	Miscellaneous Equipment	6.67	-
Total General Plant			-
Total General Plant Depreciation Expense (must tie to p336.10.b.c.d&e)	-		

INTANGIBLE PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
303	Miscellaneous Intangible Plant	20.00	-
Total Intangible Plant			-
Total Intangible Plant Amortization (must tie to p336.1 d & e)	-		

These depreciation rates will not change absent the appropriate filing at FERC.

Attachment 10

VEPCo Formula Rate for January 1, 2019 to December 31, 20189

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

Shaded cells are input cells

Line		Notes	FERC Form 1 Page # or Instruction (Note H)		2019 (000's)
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21b/ Attachment 5	$	46,344
2	Less Generator Step-ups		Attachment 5		15
3	Net Transmission Wage Expenses		(Line 1 - 2)		46,329
4	Total Wages Expense		p354.28b/Attachment 5		643,394
5	Less A&G Wages Expense		p354.27b/Attachment 5		89,022
6	Total		(Line 4 - 5)	$	554,372
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)		**8.3570%**
	Plant Allocation Factors				
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	$	42,942,198
9	Common Plant In Service - Electric		(Line 26)		0
10	Total Plant In Service		(Sum Lines 8 & 9)		42,942,198
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)		13,343,344
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5		142,048
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356/Attachment 5		0
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356/Attachment 5		0
15	Total Accumulated Depreciation		p219.29c/Attachment 5		13,485,392
16	Net Plant		(Line 10 - 15)		29,456,807
17	Transmission Gross Plant		(Line 31 - 30)		9,179,975
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)		**21.3775%**
19	Transmission Net Plant		(Line 44 - 30)	$	7,543,974
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)		**25.6103%**
	Plant Calculations				
	Plant In Service				
21	Transmission Plant In Service	(Notes A & Q)	p207.58.g/Attachment 5	$	9,600,278
22	Less: Generator Step-ups	(Notes A & Q)	Attachment 5		344,466
23	Less: Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		169,914
24	**Total Transmission Plant In Service**		(Lines 21 - 22 - 23)		**9,085,898**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5		1,125,730
26	Common Plant (Electric Only)		p356/Attachment 5		0
27	Total General & Common		(Line 25 + 26)		1,125,730
28	Wage & Salary Allocation Factor		(Line 7)		8.3570%
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**$**	**94,077**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$**	**4,513**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**$**	**9,184,488**
	Accumulated Depreciation				
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	$	1,710,354
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5		97,496
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		21,435
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)		1,591,423
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5		391,378
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)		142,048
38	Accumulated Common Amortization - Electric		(Line 13)		0
39	Common Plant Accumulated Depreciation (Electric Only)		(Line 14)		0
40	Total Accumulated Depreciation		(Sum Lines 36 to 39)		533,426
41	Wage & Salary Allocation Factor		(Line 7)		8.3570%
42	**General & Common Allocated to Transmission**		(Line 40 * 41)		**44,578**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**$**	**1,636,001**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**$**	**7,548,487**

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

		Notes	FERC Form 1 Page # or Instruction (Note H)		2019
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
45	Average Balance	(Note U)	Attachment 1	$	(1,580,365)
45A	Accumulated Deferred Income Taxes Attributable To Acquisition Adjustments		Attachment 5	$	(266)
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45 + 45A)	**$**	**(1,580,631)**
	Transmission O&M Reserves				
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**$**	**(17,187)**
	Unamortized Excess/Deficient Deferred Income Taxes				
47A	**Unamortized Exc/Def Deferral**		Attachment 5	**$**	**(2,280)**
	Prepayments				
48	Prepayments	(Notes A & R)	Attachment 5	$	2,001
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**$**	**2,001**
	Materials and Supplies				
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	$	-
51	Wage & Salary Allocation Factor		(Line 7)		8.3570%
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)		0
53	Transmission Materials & Supplies		p227.8c/2		28,638
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**$**	**28,638**
	Cash Working Capital				
55	Transmission Operation & Maintenance Expense		(Line 85)	$	127,942
56	1/8th Rule		x 1/8		12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**$**	**15,993**
	Network Credits				
58	Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
60	Net Outstanding Credits		(Line 58 - 59)		**0**
	Electric Plant Acquisition Adjustments Approved by FERC				
60A	Acquisition Adjustments Amount		Attachment 5	$	8,804
60B	Acummulated Provision for Amortization of Line 60A Amount		Attachment 5		392
60C	Transmission Plant Unamortized Acquisition Adjustments Amount		(Line 60A - 60B)	**$**	**8,411**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 47A + 49 + 54 + 57 - 60 + 60C)	**$**	**(1,545,054)**
62	**Rate Base**		(Line 44 + 61)	**$**	**6,003,433**
	O&M				
	Transmission O&M				
63	Transmission O&M		p321.112.b/Attachment 5	$	73,264
64	Less GSU Maintenance		Attachment 5		18
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5		(27,175)
66	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note O)	PJM Data		0
67	**Transmission O&M**		(Lines 63 - 64 + 65 + 66)	**$**	**100,422**
	Allocated General & Common Expenses				
68	Common Plant O&M	(Note A)	p356		0
69	Total A&G		Attachment 5		347,867
70	Less Property Insurance Account 924		p323.185b		10,083
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5		33,057
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5		5,517
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5		3,734
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$	295,476
75	Wage & Salary Allocation Factor		(Line 7)		8.3570%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**$**	**24,693**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5	$	245
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		**245**
80	Property Insurance Account 924		p323.185b		10,083
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5		0
82	Total		(Line 80 + 81)		10,083
83	Net Plant Allocation Factor		(Line 20)		25.6103%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**$**	**2,582**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**$**	**127,942**

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

			Notes	FERC Form 1 Page # or Instruction (Note H)		2019
Depreciation & Amortization Expense						
	Depreciation Expense					
86	Transmission Depreciation Expense		(Notes A and S)	p336.7b&c/Attachment 5	**$**	**240,909**
87	Less: GSU Depreciation			Attachment 5		**10,517**
88	Less Interconnect Facilities Depreciation			Attachment 5		**5,188**
89	Extraordinary Property Loss			Attachment 5		**0**
90	Total Transmission Depreciation			(Line 86 - 87 - 88 + 89)		**225,204**
90A	Amortization of Acquisition Adjustments			Attachment 5		**205**
91	General Depreciation		(Note A)	p336.10b&c&d/Attachment 5		43,517
92	Intangible Amortization		(Note A)	p336.1d&e/Attachment 5		35,071
93	Total			(Line 91 + 92)		**78,588**
94	Wage & Salary Allocation Factor			(Line 7)		8.3570%
95	**General and Intangible Depreciation Allocated to Transmission**			(Line 93 * 94)		**6,568**
96	Common Depreciation - Electric Only		(Note A)	p336.11.b		0
97	Common Amortization - Electric Only		(Note A)	p356 or p336.11d		0
98	Total			(Line 96 + 97)		0
99	Wage & Salary Allocation Factor			(Line 7)		8.3570%
100	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 98 * 99)		**0**
101	**Total Transmission Depreciation & Amortization**			**(Line 90 + 90A + 95 + 100)**	**$**	**231,977**
Taxes Other than Income						
102	**Taxes Other than Income**			Attachment 2	**$**	**64,862**
103	**Total Taxes Other than Income**			**(Line 102)**	**$**	**64,862**
Return / Capitalization Calculations						
	Long Term Interest					
104	Long Term Interest		(Note T)	p117.62c through 67c/Attachment 5	$	511,009
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
106	**Long Term Interest**			(Line 104 - 105)	$	511,009
107	**Preferred Dividends**		(Note T), enter positive	p118.29c	$	-
	Common Stock					
108	Proprietary Capital			p112.16c,d/2	$	12,044,332
109	Less Preferred Stock		(Note T), enter negative	(Line 117)		0
110	Less Account 219 - Accumulated Other Comprehensive Income		(Note T), enter negative	p112.15c,d/2	$	(54,340)
111	**Common Stock**			(Sum Lines 108 to 110)	$	11,989,992
	Capitalization					
112	Long Term Debt			p112.24c,d/2	$	11,005,768
113	Less Loss on Reacquired Debt		(Note T), enter negative	p111.81c,d/2	$	(1,869)
114	Plus Gain on Reacquired Debt		(Note T), enter positive	p113.61c,d/2	$	3,294
115	Less LTD on Securitization Bonds	(Note P)	(Note T), enter negative	Attachment 8		0
116	Total Long Term Debt			(Sum Lines 112 to 115)		11,007,193
117	Preferred Stock		(Note T), enter positive	p112.3c,d/2		0
118	Common Stock			(Line 111)		11,989,992
119	**Total Capitalization**			(Sum Lines 116 to 118)	$	22,997,186
120	Debt %	Total Long Term Debt		(Line 116 / 119)		47.9%
121	Preferred %	Preferred Stock		(Line 117 / 119)		0.0%
122	Common %	Common Stock		(Line 118 / 119)		52.1%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)		0.0464
124	Preferred Cost	Preferred Stock		(Line 107 / 117)		0.0000
125	Common Cost	Common Stock	(Note J)	Fixed		0.1140
126	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 120 * 123)		0.0222
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)		0.0000
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)		0.0594
129	**Total Return (R)**			(Sum Lines 126 to 128)		**0.0817**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**		**490,219**

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

		Notes	FERC Form 1 Page # or Instruction (Note H)		2019
Composite Income Taxes					
	Income Tax Rates				
131	FIT=Federal Income Tax Rate		Attachment 5		21.00%
132	SIT=State Income Tax Rate or Composite	(Note I)	Attachment 5		5.85%
133	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code		0.00%
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			25.62%
135	T/ (1-T)				34.45%
	Transmission Related Income Tax Adjustments				
136	Amortized Investment Tax Credit (ITC)	(Note I) enter negative	Attachment 1	$	(128)
136A	Other Income Tax Adjustments		Attachment 5	$	(2,729)
137	T/(1-T)		(Line 135)		34.45%
138	**Transmission Income Taxes - Income Tax Adjustments**		((Line 136 + 136A) * (1 + Line 137))	**$**	**(3,842)**
139	**Transmission Income Taxes - Equity Return =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**122,919**
140	**Total Transmission Income Taxes**		**(Line 138 + 139)**		**119,077**
REVENUE REQUIREMENT					
	Summary				
141	Net Property, Plant & Equipment		(Line 44)	$	7,548,487
142	Adjustment to Rate Base		(Line 61)		(1,545,054)
143	**Rate Base**		(Line 62)	**$**	**6,003,433**
144	O&M		(Line 85)		127,942
145	Depreciation & Amortization		(Line 101)		231,977
146	Taxes Other than Income		(Line 103)		64,862
147	Investment Return		(Line 130)		490,219
148	Income Taxes		(Line 140)		119,077
149					
150	**Revenue Requirement**		**(Sum Lines 144 to 149)**	**$**	**1,034,076**
	Acquisition Adjustments Revenue Requirement				
150A	Acquisition Adjustments Return		Line 129 * (60C + 45A)	$	665
150B	Acquisition Adjustments Income Taxes		[Line 135 * 150A * (1- (126 / 129))]		167
150C	Amortization of Acquisition Adjustments		(Line 90A)		205
150D	**Acquisition Adjustments Revenue Requirement**		(Line 150A + 150B + 150C)	**$**	**1,037**
	Net Plant Carrying Charge				
151	Revenue Requirement excluding Acquisition Adjustments Revenue Requirement		(Line 150 - 150D)	**$**	**1,033,040**
152	Net Transmission Plant		(Line 24 - 35)		**7,494,475**
153	Net Plant Carrying Charge without Acquisition Adjustments		(Line 151 / 152)		**13.7840%**
154	Net Plant Carrying Charge without Acquisition Adjustments and Depreciation		(Line 151 - 86) / 152		**10.5695%**
155	Net Plant Carrying Charge without Acquisition Adjustments, Depreciation, Return or Income Taxes		(Line 150 - 86 - 90A - 130 - 140) / 152		**2.4507%**
	Net Plant Carrying Charge Calculation with 100 Basis Point increase in ROE				
156	Gross Revenue Requirement Less Return, Income Taxes, and Amortization of Acquisition Adjustments		(Line 150 - 147 - 148 - 90A)	**$**	**424,576**
157	Increased Return and Taxes		Attachment 4		**650,489**
158	Net Revenue Requirement excluding Acquisition Adjustments Rev. Req. with 100 Basis Point increase in ROE		(Line 156 + 157)		**1,075,065**
159	Net Transmission Plant		(Line 152)		**7,494,475**
160	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments		(Line 158 / 159)		**14.3448%**
161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments and Depreciation		(Line 158 - 86) / 159		**11.1303%**
162	**Revenue Requirement**		(Line 150)	**$**	**1,034,076**
163	True-up Adjustment		Attachment 6		**14,027**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.		Attachment 7		**2,103**
165	Facility Credits under Section 30.9 of the PJM OATT.		Attachment 5		**3,184**
166	Revenue Credits		Attachment 3		**(44,702)**
167	Interest on Network Credits		PJM data		0
168	**Annual Transmission Revenue Requirement (ATRR)**		(Line 162 + 163 +164 + 165 + 166 + 167)	**$**	**1,008,688**
	Rate for Network Integration Transmission Service				
169	1 CP Peak	(Note L)	PJM Data		**21,232.0**
170	Rate ($/MW-Year)		(Line 168 / 169)		**47,507.93**
171	**Rate for Network Integration Transmission Service ($/MW/Year)**		**(Line 170)**		**47,507.93**

Virginia Electric and Power Company
ATTACHMENT H-16A

FERC Form 1 Page # or

Formula Rate -- Appendix A

Notes **Instruction (Note H)** **2019**

Notes

A	Electric portion only - VEPCO does not have Common Plant.
B	Excludes amounts for Generator Step-ups and Interconnection Facilities, when appropriate.
C	Includes Transmission portion only.
D	Excludes all EPRI Annual Membership Dues.
E	Includes all regulatory commission expenses.
F	Includes all safety related advertising included in Account 930.1.
G	Includes all regulatory commission expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.
H	The Form 1 reference indicates only the end-of-year balance used to derive the amount beside the reference. Each plant balance with a Form 1 reference will include the Form 1 balance in an average of the 13 month balances for the year. Each non-plant balance included in rate base with a Form 1 reference will include Form 1 balances in the calculation of the average of the beginning and end of year balances for the year. See notes Q and R below.
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. If the utility includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.
J	Per FERC order in Docket No. ER08-92, the ROE is 11.4%, which includes a 50 basis point RTO membership adder as authorized by FERC to become effective January 1, 2008. Per FERC order in Docket No. _______, the ROE for each specific project identified in that order will also include either an 150 or 125 basis point transmission incentive adder as authorized by the Commission.
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.
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 (net of accumulated depreciation) toward 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 on Line 167.
O	Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M. If they are booked to Acct 565, they are included on Line 66.
P	Securitization bonds may be included in the capital structure.
Q	Calculated using 13 month average balance. Only beginning and end of year balances are from Form 1.
R	Calculated using average of beginning and end of year balances. Beginning and end of year balances are from Form 1.
S	The depreciation rates are included in Attachment 9.
T	For the initial formula rate calculation, the projected capital structure shall reflect the capital structure from the 2006 FERC Form No. 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 No. 1 data available.
U	ADIT amounts included on Line 45A are not to be included on Line 45 or in the underlying attachments in which the Line 45 amount is computed.

Attachment 10

Virginia Electric and Power Company

Attachment 1 - Accumulated Deferred Income Tax (ADIT) Worksheet - December 31 of the Current Year

(In Thousands)

Current Year: **2019**

Wage and Salary Allocator from Line 7 of Appendix A for the Current Year	8.3570%
Gross Plant Allocator from Line 18 of Appendix A for the Current Year	21.3775%

(A)	**(B)**	**(C)**	**(D)**	**(E)**	**(F)**	**(G)**	**(H)**	**(I)**
						Transmission		
						Allocation / Assignment Method	Allocation / Assignment %	Transmission Total
Line		Account 190	Account 282	Account 283	Total			
	ADIT - Liberalized Depreciation (Amounts Including Adjustments)							
1	Liberalized Depreciation - Transmission		$ (1,505,453)		(1,505,453)	Assigned	100.0000%	(1,505,453)
2	Liberalized Depreciation - General Plant		$ (63,331)		(63,331)	Wages & Salaries	8.3570%	(5,293)
3	Liberalized Depreciation - Computer Software (Reverse Book Depreciation)		$ 48,361		48,361	Wages & Salaries	8.3570%	4,042
4	Liberalized Depreciation - Computer Software (Tax Depreciation)		$ (70,947)		(70,947)	Wages & Salaries	8.3570%	(5,929)
5	**Total Liberalized Depreciation Amounts including Adjustments (Sum of Lines 1 - 4)**	$ -	$ (1,591,370)		$ (1,591,370)			$ (1,512,633)
	ADIT - Plant Related Other than Liberalized Depreciation							
6	Transmission Plant (net of GSU/GI Proportion)	100,619	(240,083)	-	(139,465)	Assigned	100.0000%	(139,465)
7	General Plant	8,137	(29,778)	-	(21,641)	Wages & Salaries	8.3570%	(1,809)
8	Plant - Other	272,883	(25,402)	358	247,838	Gross Plant	21.3775%	52,982
9	**Total Plant Related Other than Liberalized Depreciation (Sum of Lines 6 - 8)**	$ 381,639	$ (295,263)	$ 358	$ 86,733			$ (88,291)
	ADIT - Not Plant Related							
10	Employee Benefits	206,550	-	(59,291)	147,259	Wages & Salaries	8.3570%	12,306
11	Other Operating	8,714	-	(438)	8,277	Wages & Salaries	8.3570%	692
12	**Total Not Plant Related (Sum of Lines 10 - 11)**	$ 215,264	$ -	$ (59,729)	$ 155,536			$ 12,998
13	**Total ADIT used for Assignment or Allocation to Transmission (Sum of Lines 5, 9 & 12)**	**$ 596,903**	**$ (1,886,633)**	**$ (59,371)**	**$ (1,349,101)**			**$ (1,587,926)**
	Reconciliation to FERC Form 1 Accounts:							
14	Liberalized Depreciation not Allocated or Assigned to Transmission		(4,318,175)					
15	Total Amount of Excluded ADIT in Line 5 due to Adjustments		(43,617)					
16	Excluded Amounts (see Explanations below)	2,090,753	(220,517)	(837,701)				
17	**Total ADIT Not Used for Assignment or Allocation to Transmission (Sum of Lines 14-16)**	2,090,753	(4,582,309)	(837,701)				
18	**Total FERC Form 1 Balance (Sum of Lines 13 & 17)**	$ 2,687,656	$ (6,468,942)	$ (897,072)				

Explanations:

A detailed set of work papers supporting these inputs shall be included with the work papers posted on the PJM website and included in the informational filing with the Commission.

Lines 1-4 inputs are from Attachment 1B if the inputs are for a projected rate calculation or from Attachment 1C if the inputs are for a true-up calculation.

Lines 6-8, 10-11 and 14 inputs are totals for each category by account obtained from work papers maintained by the Tax Department.

Line 15 represents the impact of proration and the removal of ADIT associated with generator step-up transformers as determined on Attachment 1B or 1C, as applicable. It is the mathematical difference between the inputs for Lines 1-4 and the unadjusted amounts provided in the applicable Attachment 1B or 1C.

Line 16 inputs are excluded ADIT items (not otherwise listed in Lines 14 and 15) from the Formula Rate such as ADIT associated with the production and distribution functions, non-operating income and deductions, and other comprehensive income entries or unfunded ADIT balances primarily due to the adoption of SFAS No. 109.

Virginia Electric and Power Company

Attachment 1 -- Continued

(In Thousands)

Line

ADIT Summary and Calculation of Average Balance

Line	Description	Balance Date	Amount
19	Transmission Total ADIT from Attachment 1, Line 13	December 31 of the Current Year	$ (1,587,926)
20	Transmission Total ADIT from Attachment 1A, Line 13 (Note 1)	December 31 of the Previous Year	$ (1,572,803)
21	Average Balance for Entry on Line 45 of Appendix A		$ (1,580,365)

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet -- Amortization of ITC-255

Line	Item	Amortization
22	Amortization of Transmission Related for Entry on Line 136 of Appendix A	$ 128
23	Amortization, Other	$ (2,977)
24	Current Year Amortization (Line 22 + 23)	$ (2,849)
25	Current Year Amortization from Form 1 (Current Year Items from p266.8f-g)	$ (2,849)
26	Difference (Line 24 - 25) (Must be Zero)	$ -

Note (1): For the true-up of 2017 only, the value entered on Line 20 shall be the December 31, 2016 ADIT balance from the 2016 true-up population of the formula rate in effect on December 31, 2016.

Attachment 10

Virginia Electric and Power Company

Attachment 1A - Accumulated Deferred Income Tax (ADIT) Worksheet - December 31 of the Previous Year

(In Thousands)

Previous Year: 2018

For the true-up of 2017, this Attachment 1A shall not be populated. The December 31, 2016 ADIT balance used in Attachment 1 of the 2017 true-up population shall be the December 31, 2016 ADIT balance from the 2016 true-up population of the formula rate in effect on December 31, 2016.

Wage and Salary Allocator from Line 7 of Appendix A for the Previous Year	8.3570%
Gross Plant Allocator from Line 18 of Appendix A for the Previous Year	21.3775%

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
						Transmission		
Line		Account 190	Account 282	Account 283	Total	Allocation / Assignment Method	Allocation / Assignment %	Transmission Total
	ADIT - Liberalized Depreciation (Amounts Including Adjustments)							
1	Liberalized Depreciation - Transmission		$ (1,490,330)		(1,490,330)	Assigned	100.0000%	(1,490,330)
2	Liberalized Depreciation - General Plant		$ (63,331)		(63,331)	Wages & Salaries	8.3570%	(5,293)
3	Liberalized Depreciation - Computer Software (Reverse Book Depreciation)		$ 48,361		48,361	Wages & Salaries	8.3570%	4,042
4	Liberalized Depreciation - Computer Software (Tax Depreciation)		$ (70,947)		(70,947)	Wages & Salaries	8.3570%	(5,929)
5	**Total Liberalized Depreciation Amounts including Adjustments (Sum of Lines 1 - 4)**	$ -	$ (1,576,247)		$ (1,576,247)			$ (1,497,510)
	ADIT - Plant Related Other than Liberalized Depreciation							
6	Transmission Plant (net of GSU/GI Proportion)	100,619	(240,083)	-	(139,465)	Assigned	100.0000%	(139,465)
7	General Plant	8,137	(29,778)	-	(21,641)	Wages & Salaries	8.3570%	(1,809)
8	Plant - Other	272,883	(25,402)	358	247,838	Gross Plant	21.3775%	52,982
9	**Total Plant Related Other than Liberalized Depreciation (Sum of Lines 6 - 8)**	$ 381,639	$ (295,263)	$ 358	$ 86,733			$ (88,291)
	ADIT - Not Plant Related							
10	Employee Benefits	206,550	-	(59,291)	147,259	Wages & Salaries	8.3570%	12,306
11	Other Operating	8,714	-	(438)	8,277	Wages & Salaries	8.3570%	692
12	**Total Not Plant Related (Sum of Lines 10 - 11)**	$ 215,264	$ -	$ (59,729)	$ 155,536			$ 12,998
13	**Total ADIT used for Assignment or Allocation to Transmission (Sum of Lines 5, 9 & 12)**	**$ 596,903**	**$ (1,871,510)**	**$ (59,371)**	**$ (1,333,978)**			**$ (1,572,803)**
	Reconciliation to FERC Form 1 Accounts:							
14	Liberalized Depreciation not Allocated or Assigned to Transmission		(4,299,979)					
15	Total Amount of Excluded ADIT in Line 5 due to Adjustments		(94,538)					
16	Excluded Amounts (see Explanations below)	2,090,753	(220,517)	(837,701)				
17	**Total ADIT Not Used for Assignment or Allocation to Transmission (Sum of Lines 14-16)**	2,090,753	(4,615,034)	(837,701)				
18	**Total FERC Form 1 Balance (Sum of Lines 13 & 17)**	$ 2,687,656	$ (6,486,544)	$ (897,072)				

Explanations:

A detailed set of work papers supporting these inputs shall be included with the work papers posted on the PJM website and included in the informational filing with the Commission.

Lines 1-4 inputs are from Attachment 1B if the inputs are for a projected rate calculation or from Attachment 1C if the inputs are for a true-up calculation.

Lines 6-8, 10-11 and 14 inputs are totals for each category by account obtained from work papers maintained by the Tax Department.

Line 15 represents the impact of proration and the removal of ADIT associated with generator step-up transformers as determined on Attachment 1B or 1C, as applicable. It is the mathematical difference between the inputs for Lines 1-4 and the unadjusted amounts provided in the applicable Attachment 1B or 1C.

Line 16 inputs are excluded ADIT items (not otherwise listed in Lines 14 and 15) from the Formula Rate such as ADIT associated with the production and distribution functions, non-operating income and deductions, and other comprehensive income entries or unfunded ADIT balances primarily due to the adoption of SFAS No. 109.

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1B
Projected Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable to the Projections of 2016 and Later and True-ups of 2014 and Later

If the formula rate population is for determining a projected ATRR, enter the year for which the projection is being made on line 1 and populate the remainder of this Attachment 1B with the projected data associated with that year. If the formula rate population is for determining a true-up ATRR for use on Line A of Attachment 6, enter the year for which the true-up is being calculated on line 1 and populate the remainder of this Attachment 1B with the data that was included in Attachment 1B of the projection associated with that year.

Sheet 1 of 3

Line 1	Projection for Year:	2019	
Line 2	Number of Days in Year:	365	(Enter 365, or for Leap Year enter 366)

Part 1: Account 282, Transmission Plant In Service

Columns 3, 4, 7, and 8 are in dollars (except line 16).

Line	(1) Year	(2) Month	(3) Projected Transmission Plant in Service ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
3	2018	Dec	(1,574,701,805)					(1,574,701,805)
4	2019	Jan	(1,577,649,993)	(2,948,188)	335	0.917808	(2,705,871)	(1,577,407,676)
5	2019	Feb	(1,580,576,846)	(2,926,852)	307	0.841096	(2,461,763)	(1,579,869,439)
6	2019	Mar	(1,583,495,278)	(2,918,433)	276	0.756164	(2,206,815)	(1,582,076,254)
7	2019	Apr	(1,586,384,633)	(2,889,355)	246	0.673973	(1,947,346)	(1,584,023,600)
8	2019	May	(1,589,250,768)	(2,866,135)	215	0.589041	(1,688,271)	(1,585,711,871)
9	2019	Jun	(1,592,092,122)	(2,841,354)	185	0.506849	(1,440,138)	(1,587,152,009)
10	2019	Jul	(1,594,887,107)	(2,794,986)	154	0.421918	(1,179,254)	(1,588,331,263)
11	2019	Aug	(1,597,655,474)	(2,768,367)	123	0.336986	(932,902)	(1,589,264,165)
12	2019	Sep	(1,600,413,774)	(2,758,300)	93	0.254795	(702,800)	(1,589,966,965)
13	2019	Oct	(1,603,163,347)	(2,749,572)	62	0.169863	(467,051)	(1,590,434,016)
14	2019	Nov	(1,605,897,026)	(2,733,679)	32	0.087671	(239,665)	(1,590,673,681)
15	2019	Dec	(1,608,565,605)	(2,668,580)	1	0.002740	(7,311)	(1,590,680,992)
16	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:							94.64%
17	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							(1,490,329,757)
18	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:							(1,505,452,784)

Explanations:

Col. 3	Projected Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 5	Number of days remaining in the year as of and including the last day of the month.
Col. 6	Col. 5 divided by the number of days in the year.
Col. 7	Col. 4 multiplied by col. 6.
Col. 8, Line 3	Amount from col. 3, line 3.
Col. 8, Lines 4-15	Col. 8 of previous month plus col. 7 of current month.
Col. 8, Line 16	Appendix A Line 24 ÷ Appendix A, Line 21 (from the projection population of the formula)
Col. 8, Line 17	Col. 8, Line 3 multiplied by line 16.
Col. 8, Line 18	Col. 8, Line 15 multiplied by line 16.

Attachment 1B (Continued)
2019
Sheet 2 of 3

Part 2: Account 282, General Plant

Columns 3, 4, 7, and 8 are in dollars.

Line	(1) Year	(2) Month	(3) Projected General Plant ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2018	Dec	(63,330,518)					(63,330,518)
2	2019	Jan	(63,330,518)	0	335	0.917808	0	(63,330,518)
3	2019	Feb	(63,330,518)	0	307	0.841096	0	(63,330,518)
4	2019	Mar	(63,330,518)	0	276	0.756164	0	(63,330,518)
5	2019	Apr	(63,330,518)	0	246	0.673973	0	(63,330,518)
6	2019	May	(63,330,518)	0	215	0.589041	0	(63,330,518)
7	2019	Jun	(63,330,518)	0	185	0.506849	0	(63,330,518)
8	2019	Jul	(63,330,518)	0	154	0.421918	0	(63,330,518)
9	2019	Aug	(63,330,518)	0	123	0.336986	0	(63,330,518)
10	2019	Sep	(63,330,518)	0	93	0.254795	0	(63,330,518)
11	2019	Oct	(63,330,518)	0	62	0.169863	0	(63,330,518)
12	2019	Nov	(63,330,518)	0	32	0.087671	0	(63,330,518)
13	2019	Dec	(63,330,518)	0	1	0.002740	0	(63,330,518)

14	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:	(63,330,518)
15	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:	(63,330,518)

Explanations:

Col. 3	Projected Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Current month change in ADIT balance.
Col. 5	Number of days remaining in the year as of and including the last day of the month.
Col. 6	Col. 5 divided by the number of days in the year.
Col. 7	Col. 4 multiplied by Col. 6.
Col. 8, Line 1	Amount from col. 3, line 1.
Col. 8, Lines 2-13	Col. 8 of previous month plus Col. 7 of current month.
Col. 8, Line 14	Col. 8, Line 1.
Col. 8, Line 15	Col. 8, Line 13.

Attachment 1B (Continued)
2019
Sheet 3 of 3

Part 3: Account 282, Computer Software - Book Amortization

Columns 3, 4, 7, and 8 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Projected Computer Software Book Amount ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2018	Dec	48,360,787					48,360,787
2	2019	Jan	48,360,787	0	335	0.917808	0	48,360,787
3	2019	Feb	48,360,787	0	307	0.841096	0	48,360,787
4	2019	Mar	48,360,787	0	276	0.756164	0	48,360,787
5	2019	Apr	48,360,787	0	246	0.673973	0	48,360,787
6	2019	May	48,360,787	0	215	0.589041	0	48,360,787
7	2019	Jun	48,360,787	0	185	0.506849	0	48,360,787
8	2019	Jul	48,360,787	0	154	0.421918	0	48,360,787
9	2019	Aug	48,360,787	0	123	0.336986	0	48,360,787
10	2019	Sep	48,360,787	0	93	0.254795	0	48,360,787
11	2019	Oct	48,360,787	0	62	0.169863	0	48,360,787
12	2019	Nov	48,360,787	0	32	0.087671	0	48,360,787
13	2019	Dec	48,360,787	0	1	0.002740	0	48,360,787
14	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							48,360,787
15	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:							48,360,787

Part 4: Account 282, Computer Software - Tax Amortization

Columns 3, 4, 7, and 8 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Projected Computer Software Tax Amount ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2018	Dec	(70,947,088)					(70,947,088)
2	2019	Jan	(70,947,088)	0	335	0.917808	0	(70,947,088)
3	2019	Feb	(70,947,088)	0	307	0.841096	0	(70,947,088)
4	2019	Mar	(70,947,088)	0	276	0.756164	0	(70,947,088)
5	2019	Apr	(70,947,088)	0	246	0.673973	0	(70,947,088)
6	2019	May	(70,947,088)	0	215	0.589041	0	(70,947,088)
7	2019	Jun	(70,947,088)	0	185	0.506849	0	(70,947,088)
8	2019	Jul	(70,947,088)	0	154	0.421918	0	(70,947,088)
9	2019	Aug	(70,947,088)	0	123	0.336986	0	(70,947,088)
10	2019	Sep	(70,947,088)	0	93	0.254795	0	(70,947,088)
11	2019	Oct	(70,947,088)	0	62	0.169863	0	(70,947,088)
12	2019	Nov	(70,947,088)	0	32	0.087671	0	(70,947,088)
13	2019	Dec	(70,947,088)	0	1	0.002740	0	(70,947,088)
14	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							(70,947,088)
15	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:							(70,947,088)

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1C
True-up of Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable to the True-ups of 2015 and Later

If the formula rate population is for determining a projected ATRR, do not populate this Attachment 1C. If the formula rate population is for determining a true-up ATRR for use on Line A of Attachment 6, enter the year for which the true-up is being calculated on line 1 and populate the remainder of this Attachment 1C with the actual data associated with that year. Use the amounts from lines 17 and 18 of Part 1, and lines 14 and 15 of Parts 2, 3, and 4, in populating Attachment 1 and Attachment 1A as instructed in this Attachment 1C.

Sheet 1 of 3

Line 1	True-up Year:		(If Populated, Must Match Attachment 1B, Part 1, Line 1)
Line 2	Number of Days in Year:	365	(From Attachment 1B, Part 1, Line 2)

Part 1: Account 282, Transmission Plant In Service

Columns 3 through 12 are in dollars (except line 16).

Line	(1) Year	(2) Month	(3) Actual Transmission Plant In Service ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
3	-	Dec										-
4	-	Jan		-		-	-	-	-		-	-
5	-	Feb		-		-	-	-	-		-	-
6	-	Mar		-		-	-	-	-		-	-
7	-	Apr		-		-	-	-	-		-	-
8	-	May		-		-	-	-	-		-	-
9	-	Jun		-		-	-	-	-		-	-
10	-	Jul		-		-	-	-	-		-	-
11	-	Aug		-		-	-	-	-		-	-
12	-	Sep		-		-	-	-	-		-	-
13	-	Oct		-		-	-	-	-		-	-
14	-	Nov		-		-	-	-	-		-	-
15	-	Dec		-		-	-	-	-		-	-

16 Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:

17 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: -

18 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: -

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 1.
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 3	Amount from col. 3, line 3.
Col. 12, Lines 4-15	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 16	Appendix A, Line 24 ÷ Appendix A, Line 21 (from the true-up population of the formula)
Col. 12, Line 17	Col. 12, Line 3 multiplied by line 16.
Col. 12, Line 18	Col. 12, Line 15 multiplied by line 16.

Attachment 1C (Continued)
-
Sheet 2 of 3

Part 2: Account 282, General Plant

Columns 3 through 12 are in dollars.

Line	(1) Year	(2) Month	(3) Actual General Plant ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	-	Dec										-
2	-	Jan		-		-	-	-	-		-	-
3	-	Feb		-		-	-	-	-		-	-
4	-	Mar		-		-	-	-	-		-	-
5	-	Apr		-		-	-	-	-		-	-
6	-	May		-		-	-	-	-		-	-
7	-	Jun		-		-	-	-	-		-	-
8	-	Jul		-		-	-	-	-		-	-
9	-	Aug		-		-	-	-	-		-	-
10	-	Sep		-		-	-	-	-		-	-
11	-	Oct		-		-	-	-	-		-	-
12	-	Nov		-		-	-	-	-		-	-
13	-	Dec		-		-	-	-	-		-	-

14 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: -

15 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: -

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 2, 3 or 4 (as appropriate).
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 1	Amount from col. 3, line 1.
Col. 12, Lines 2-13	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 14	Amount from col. 12, line 1.
Col. 12, Line 15	Amount from col. 12, line 13.

Attachment 1C (Continued)
-
Sheet 3 of 3

Part 3: Account 282, Computer Software - Book Amortization

Columns 3 through 12 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Book Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	-	Dec										-
2	-	Jan		-		-	-	-	-		-	-
3	-	Feb		-		-	-	-	-		-	-
4	-	Mar		-		-	-	-	-		-	-
5	-	Apr		-		-	-	-	-		-	-
6	-	May		-		-	-	-	-		-	-
7	-	Jun		-		-	-	-	-		-	-
8	-	Jul		-		-	-	-	-		-	-
9	-	Aug		-		-	-	-	-		-	-
10	-	Sep		-		-	-	-	-		-	-
11	-	Oct		-		-	-	-	-		-	-
12	-	Nov		-		-	-	-	-		-	-
13	-	Dec		-		-	-	-	-		-	-

14 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: -

15 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: -

Part 4: Account 282, Computer Software - Tax Amortization

Columns 3 through 12 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Tax Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	-	Dec										-
2	-	Jan		-		-	-	-	-		-	-
3	-	Feb		-		-	-	-	-		-	-
4	-	Mar		-		-	-	-	-		-	-
5	-	Apr		-		-	-	-	-		-	-
6	-	May		-		-	-	-	-		-	-
7	-	Jun		-		-	-	-	-		-	-
8	-	Jul		-		-	-	-	-		-	-
9	-	Aug		-		-	-	-	-		-	-
10	-	Sep		-		-	-	-	-		-	-
11	-	Oct		-		-	-	-	-		-	-
12	-	Nov		-		-	-	-	-		-	-
13	-	Dec		-		-	-	-	-		-	-

14 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: -

15 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: -

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1C - 2014
True-up of Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable Only to the True-up of 2014

If the formula rate population is for determining the 2014 true-up ATRR for use on Line A of Attachment 6, populate this Attachment 1C - 2014 with the actual data associated with that year. Use the amounts from lines 17 and 18 of Part 1, and lines 14 and 15 of Parts 2, 3, and 4, in populating Attachment 1 and Attachment 1A as instructed in this Attachment 1C - 2014.

Sheet 1 of 4

Line 1	True-up Year:	2014
Line 2	Number of Days in Year:	365

Part 1: Account 282, Transmission Plant In Service

Columns 3 through 12 are in dollars (except lines 15b, 15e, and 16).

Line	(1) Year	(2) Month	(3) Actual Transmission Plant In Service ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
3	2013	Dec										-
4	2014	Jan		-		-	-	-	-		-	-
5	2014	Feb		-		-	-	-	-		-	-
6	2014	Mar		-		-	-	-	-		-	-
7	2014	Apr		-		-	-	-	-		-	-
8	2014	May		-		-	-	-	-		-	-
9	2014	Jun		-		-	-	-	-		-	-
10	2014	Jul		-		-	-	-	-		-	-
11	2014	Aug		-		-	-	-	-		-	-
12	2014	Sep		-		-	-	-	-		-	-
13	2014	Oct		-		-	-	-	-		-	-
14	2014	Nov		-		-	-	-	-		-	-
15	2014	Dec		-		-	-	-	-		-	-

15a	Pre-change -- Average of Actual ADIT Balance from Col. 3, December 2013 and April 2014	-
15b	4 Months Divided by 12 Months	33.33%
15c	Component of Average ADIT Balance Attributable to January Through April (15a X 15b)	-
15d	Post-change -- Average of ADIT Balances for True-up from Col. 12, April 2014 and December 2014	-
15e	8 Months Divided by 12 Months	66.67%
15f	Component of Average ADIT Balance Attributable to May Through December (15d X 15e)	-
15g	Pre-change Component plus Post-change Component (15c + 15f)	-
16	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:	
17	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-
18	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).	Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 4	Monthly change in ADIT balance.	Col. 12, Line 3	Amount from col. 3, line 3.
Col. 6	Col. 4 minus col. 5	Col. 12, Lines 4-15	Col. 12 of previous month plus col. 11 of current month.
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.	Col. 12, Line 16	Appendix A, Line 24 ÷ Appendix A, Line 21 (from the true-up population of the formula)
Col. 8	The portion of the amount in col. 6 not included in original projection.	Col. 12, Line 17	Col. 12, Line 15g multiplied by line 16.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 1.	Col. 12, Line 18	Col. 12, Line 15g multiplied by line 16.

Attachment 1C - 2014 (Continued)
2014
Sheet 2 of 4

Part 2: Account 282, General Plant

Columns 3 through 12 are in dollars (except lines 13b and 13e).

Line	(1) Year	(2) Month	(3) Actual General Plant ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	2013	Dec										-
2	2014	Jan		-		-	-	-	-		-	-
3	2014	Feb		-		-	-	-	-		-	-
4	2014	Mar		-		-	-	-	-		-	-
5	2014	Apr		-		-	-	-	-		-	-
6	2014	May		-		-	-	-	-		-	-
7	2014	Jun		-		-	-	-	-		-	-
8	2014	Jul		-		-	-	-	-		-	-
9	2014	Aug		-		-	-	-	-		-	-
10	2014	Sep		-		-	-	-	-		-	-
11	2014	Oct		-		-	-	-	-		-	-
12	2014	Nov		-		-	-	-	-		-	-
13	2014	Dec		-		-	-	-	-		-	-

Line		
13a	Pre-change -- Average of Actual ADIT Balance from Col. 3, December 2013 and April 2014	-
13b	4 Months Divided by 12 Months	33.33%
13c	Component of Average ADIT Balance Attributable to January Through April (13a X 13b)	-
13d	Post-change -- Average of ADIT Balances for True-up from Col. 12, April 2014 and December 2014	-
13e	8 Months Divided by 12 Months	66.67%
13f	Component of Average ADIT Balance Attributable to May Through December (13d X 13e)	-
13g	Pre-change Component plus Post-change Component (13c + 13f)	-
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 2, 3 or 4 (as appropriate).
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 1	Amount from col. 3, line 1.
Col. 12, Lines 2-13	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 14	Amount from col. 12, line 13g.
Col. 12, Line 15	Amount from col. 12, line 13g.

Attachment 1C - 2014 (Continued)
2014
Sheet 3 of 4

Part 3: Account 282, Computer Software - Book Amortization

Columns 3 through 12 are in dollars (except lines 13b and 13e).
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Book Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	2013	Dec										-
2	2014	Jan		-		-	-	-	-		-	-
3	2014	Feb		-		-	-	-	-		-	-
4	2014	Mar		-		-	-	-	-		-	-
5	2014	Apr		-		-	-	-	-		-	-
6	2014	May		-		-	-	-	-		-	-
7	2014	Jun		-		-	-	-	-		-	-
8	2014	Jul		-		-	-	-	-		-	-
9	2014	Aug		-		-	-	-	-		-	-
10	2014	Sep		-		-	-	-	-		-	-
11	2014	Oct		-		-	-	-	-		-	-
12	2014	Nov		-		-	-	-	-		-	-
13	2014	Dec		-		-	-	-	-		-	-

13a	Pre-change -- Average of Actual ADIT Balance from Col. 3, December 2013 and April 2014	-
13b	4 Months Divided by 12 Months	33.33%
13c	Component of Average ADIT Balance Attributable to January Through April (13a X 13b)	-
13d	Post-change -- Average of ADIT Balances for True-up from Col. 12, April 2014 and December 2014	-
13e	8 Months Divided by 12 Months	66.67%
13f	Component of Average ADIT Balance Attributable to May Through December (13d X 13e)	-
13g	Pre-change Component plus Post-change Component (13c + 13f)	-
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-

Attachment 1C - 2014 (Continued)
2014
Sheet 4 of 4

Part 4: Account 282, Computer Software - Tax Amortization

Columns 3 through 12 are in dollars (except lines 13b and 13e).
The column and line explanations are as described for Part 2.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line	Year	Month	Actual Computer Software Tax Amount ADIT	Actual Activity	Projected Activity from Column (4) of Attachment 1B	Activity Difference	Reversal of Projected Activity Not Realized	Activity Not in Projection	Reversal of Projected Activity Not Realized With Proration	Projected Activity With Proration from Column (7) of Attachment 1B	ADIT Activity for True-up	ADIT Balances for True-up
1	2013	Dec										-
2	2014	Jan		-		-	-	-	-		-	-
3	2014	Feb		-		-	-	-	-		-	-
4	2014	Mar		-		-	-	-	-		-	-
5	2014	Apr		-		-	-	-	-		-	-
6	2014	May		-		-	-	-	-		-	-
7	2014	Jun		-		-	-	-	-		-	-
8	2014	Jul		-		-	-	-	-		-	-
9	2014	Aug		-		-	-	-	-		-	-
10	2014	Sep		-		-	-	-	-		-	-
11	2014	Oct		-		-	-	-	-		-	-
12	2014	Nov		-		-	-	-	-		-	-
13	2014	Dec		-		-	-	-	-		-	-

13a	Pre-change -- Average of Actual ADIT Balance from Col. 3, December 2013 and April 2014	-
13b	4 Months Divided by 12 Months	33.33%
13c	Component of Average ADIT Balance Attributable to January Through April (13a X 13b)	-
13d	Post-change -- Average of ADIT Balances for True-up from Col. 12, April 2014 and December 2014	-
13e	8 Months Divided by 12 Months	66.67%
13f	Component of Average ADIT Balance Attributable to May Through December (13d X 13e)	-
13g	Pre-change Component plus Post-change Component (13c + 13f)	-
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 2 - Taxes Other Than Income Worksheet
2019 (000's)

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
	Plant Related		***Gross Plant Allocator***	
1	Transmission Personal Property Tax (directly assigned to Transmission)	$ 61,249	100.0000%	$ 61,249
1a	Other Plant Related Taxes	0	21.3775%	-
2				-
3				-
4				-
5				-
				-
	Total Plant Related	$ 61,249		$ 61,249
	Labor Related		***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & State Unemployment	$ 43,233		
	Total Labor Related	$ 43,233	8.3570%	$ 3,613
	Other Included		***Gross Plant Allocator***	
7	Sales and Use Tax	$ -		
	Total Other Included	$ -	21.3775%	$ -
	Total Included	$ 104,482		$ 64,862
	Currently Excluded			
8	Business and Occupation Tax - West Virginia	$ 20,745		
9	Gross Receipts Tax	0		
10	IFTA Fuel Tax	7		
11	Property Taxes - Other	195,577		
12	Property Taxes - Generator Step-Ups and Interconnects	2,973		
13	Sales and Use Tax - not allocated to Transmission	3,636		
14	Sales and Use Tax - Retail	0		
15	Other	32,409		
16		0		
17		0		
18		0		
19		0		
20		0		
21	Total "Other" Taxes (included on p. 263)	$ 255,348		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	$ 359,830		
23	Difference	$ (104,482)		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be either directly assigned or allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included.

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 will 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 Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

VEPCO
ATTACHMENT H-16A
Attachment 2A - Direct Assignment of Property Taxes Per Function
2019 (000's)

Directly Assigned Property Taxes	$	259,799
Production Property Tax		100,324
Transmission Property Tax		61,106
GSU/Interconnect Facilities		2,973
Distribution Property tax		93,682
General Property Tax		1,713
Total check		259,799

Allocation of General Property Tax to Transmission

General Property Tax	$	1,713
Wages & Salary Allocator		8.3570%
Trans General		143

Total Transmission Property Taxes		
Transmission	$	61,106
General		143
Total Transmission Property Taxes	$	61,249

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
2019 (000's)

			Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)		13,763		13,763
2	Total Rent Revenues	(Sum Lines 1)	13,763	-	13,763
	Account 456 - Other Electric Revenues (Note 1)				
3	Schedule 1A				
4	Net revenues associated with Network Integration Transmission Service (NITS) and for the transmission component of the NCEMPA contract rate for which the load is not included in the divisor. (Note 4)		1,440		1,440
5	Point to Point Service revenues received by Transmission Owner for which the load is not included in the divisor (Note 4)		-		-
6	PJM Transitional Revenue Neutrality (Note 1)		-		-
7	PJM Transitional Market Expansion (Note 1)		-		-
8	Professional Services (Note 3)		1,972		1,972
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		36,791		36,791
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)				-
11	Gross Revenue Credits (Accounts 454 and 456)	(Sum Lines 2-10)	53,966	-	53,966
12	Less line 14g		(9,264)	-	(9,264)
13	Total Revenue Credits		44,702	-	44,702
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		15,735	-	15,735
14b	Costs associated with revenues in line 14a		2,792	-	2,792
14c	Net Revenues (14a - 14b)		12,943	-	12,943
14d	50% Share of Net Revenues (14c / 2)		6,472	-	6,472
14e	Cost associated with revenues in line 14b 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		-	-	-
14f	Net Revenue Credit (14d + 14e)		6,472	-	6,472
14g	Line 14f less line 14a		(9,264)	-	(9,264)

Revenue Adjustment to Determine Revenue Credit

Note 1: All revenues related to transmission that are received as a transmission owner (*i.e* ., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 169 of Appendix A.

Note 2: 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. Notwithstanding the above, the revenue crediting of the UG Transmission Charge revenues shall be in accordance with section 6 of Attachment 10.

Note 3: 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). VEPCO will retain 50% of net revenues consistent with *Pacific Gas and Electric Company* , 90 FERC ¶ 61,314. In order to use lines 14a - 14g, 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).

Note 4: Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12. In addition, revenues from Schedule 7, Schedule 8 and H-A are not included in the total above to the extent PJM credits VEPCO's share of these revenues monthly to network customers under Attachment H-16.

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 4 - Calculation of 100 Basis Point Increase in ROE
2019 (000's)

	Return and Taxes with Basis Point increase in ROE				
A		Basis Point increase in ROE and Income Taxes		(Line 130 + 140)	650,489
B		100 Basis Point increase in ROE (Note J from Appendix A)		Fixed	1.00%
Return Calculation					
Line Ref.					
62	Rate Base excluding Acquisition Adjustments Amount and Associated ADIT		Appendix A	(Line 44 + 61 - 60C - 45A)	5,995,287
	Long Term Interest				
104		**Long Term Interest**		p117.62c through 67c	511,009
105		Less LTD Interest on Securitization (Note P)		Attachment 8	0
106		Long Term Interest		(Line 104 - 105)	511,009
107	Preferred Dividends		enter positive	p118.29c	0
	Common Stock				
108		Proprietary Capital		p112.16c,d/2	12,044,332
109		Less Preferred Stock	enter negative	(Line 117)	0
110		Less Account 219 - Accumulated Other Comprehensive Income	enter negative	p112.15c,d/2	-54,340
111		Common Stock		(Sum Lines 108 to 110)	11,989,992
	Capitalization				
112		Long Term Debt		p112.24c,d/2	11,005,768
113		Less Loss on Reacquired Debt	enter negative	p111.81c,d/2	-1,869
114		Plus Gain on Reacquired Debt	enter positive	p113.61c,d/2	3,294
115		Less LTD on Securitization Bonds	enter negative	Attachment 8	0
116		Total Long Term Debt		(Sum Lines 112 to 115)	11,007,193
117		Preferred Stock		p112.3c,d/2	0
118		Common Stock		(Line 111)	11,989,992
119		Total Capitalization		(Sum Lines 116 to 118)	22,997,186
120		Debt %	Total Long Term Debt	(Line 116 / 119)	47.9%
121		Preferred %	Preferred Stock	(Line 117 / 119)	0.0%
122		Common %	Common Stock	(Line 118 / 119)	52.1%
123		Debt Cost	Total Long Term Debt	(Line 106 / 116)	0.0464
124		Preferred Cost	Preferred Stock	(Line 107 / 117)	0.0000
125		Common Cost	Common Stock	Appendix A Line 125 + 100 Basis Points	0.1240
126		Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 120 * 123)	0.0222
127		Weighted Cost of Preferred	Preferred Stock	(Line 121 * 124)	0.0000
128		Weighted Cost of Common	Common Stock	(Line 122 * 125)	0.0646
129	Total Return (R)			**(Sum Lines 126 to 128)**	**0.0869**
130	Investment Return = Rate Base * Rate of Return			**(Line 62 * 129)**	**520,811**
Composite Income Taxes					
	Income Tax Rates				
131		FIT=Federal Income Tax Rate			0.2100
132		SIT=State Income Tax Rate or Composite			0.0585
133		p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.0000
134		T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.2562
135		T/ (1-T)			0.3445
	Transmission Related Income Tax Adjustments				
136	Amortized Investment Tax Credit (ITC)	(Note I) enter negative	Attachment 1		$ (128)
136A	Other Income Tax Adjustments		Attachment 5		$ (2,729)
137	T/(1-T)		(Line 135)		34.45%
138	**Transmission Income Taxes - Income Tax Adjustments**		((Line 136 + 136A) * (1 + Line 137))		**$ (3,842)**
139	**Transmission Income Taxes - Equity Return =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**133,520**
140	**Total Transmission Income Taxes**		**(Line 138 + 139)**		**129,678**

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2019 - Projection

Attachment 10

Electric / Non-electric Cost Support

				Previous Year	Current Year														
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric Portion	Details
	Plant Allocation Factors																		
8	Electric Plant in Service	(Notes A & Q)	p207.104g/Plant-Acc. Deprc Wkst	41,916,458	42,008,529	42,114,581	42,499,365	42,586,838	42,681,787	42,977,824	43,124,388	43,293,977	43,397,530	43,466,280	43,677,854	44,503,166	42,942,198	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c	12,993,141	13,076,917	13,160,109	13,238,710	13,319,706	13,401,441	13,482,810	13,565,613	13,647,894	13,729,723	13,813,072	13,897,745	13,983,213	13,485,392	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c	136,272	137,235	138,197	139,160	140,123	141,085	142,048	143,010	143,973	144,936	145,898	146,861	147,823	142,048	0	Respondent is Electric Utility only.
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Plant In Service																		
21	Transmission Plant in Service	(Notes A & Q)	p207.58.g/Trans.Input Sht	9,235,990	9,261,141	9,287,747	9,551,704	9,558,498	9,591,064	9,634,268	9,654,701	9,691,633	9,723,779	9,735,786	9,828,796	10,048,503	9,600,278	0	
15	Generator Step-Ups		Trans. Input Sht	344,466	344,466	344,466	344,466	344,466	344,466	344,466	344,466	344,466	344,466	344,466	344,466	344,466	344,466	0	
23	Generator Interconnect Facilities		Input Sht	169,914	169,914	169,914	169,914	169,914	169,914	169,914	169,914	169,914	169,914	169,914	169,914	169,914	169,914		
25	General & Intangible		p205.5.g & p207.99.g/G&I Wksht	1,099,870	1,104,180	1,108,490	1,112,800	1,117,110	1,121,420	1,125,730	1,130,040	1,134,350	1,138,660	1,142,970	1,147,280	1,151,590	1,125,730	0	
26	Common Plant (Electric Only)	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Accumulated Depreciation																		
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Trans.Input Sht	1,607,629	1,624,222	1,640,870	1,657,824	1,675,064	1,692,347	1,709,711	1,727,142	1,744,635	1,762,201	1,779,815	1,797,540	1,815,596	1,710,354	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht	92,237	93,114	93,990	94,866	95,743	96,619	97,496	98,372	99,249	100,125	101,001	101,878	102,754	97,496	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht	18,841	19,274	19,706	20,138	20,571	21,003	21,435	21,868	22,300	22,732	23,165	23,597	24,029	21,435		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b	380,644	382,433	384,222	386,011	387,800	389,589	391,378	393,167	394,956	396,745	398,534	400,323	402,112	391,378	0	
	Materials and Supplies																		
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses																		
68	Common Plant O&M	(Note A)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Depreciation Expense																Electric		
86	Depreciation-Transmission	(Note A)	p336.7.b&c														240,909	0	
91	Depreciation-General	(Note A)															43,517	0	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5														35,071	0	Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																10,517	0	
88	Depreciation - Interconnection Facilities																5,188	0	
96	Common Depreciation - Electric Only	(Note A)	p336.11.b														-	0	
97	Common Amortization - Electric Only	(Note A)	p356 or p336.11d														-	0	

O&M Expenses

				Previous Year	Current Year														
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Totals	Non-electric Portion	Details
63	Transmission O&M	(Note A)	p321.112.b/Trans. Input Sht	-	5,150	5,894	5,830	5,408	5,681	7,005	6,357	6,660	6,352	6,912	5,586	6,429	73,264	27,995	
64	Generator Step-Ups		Input Sheet		-	-	-	-	-	-	-	-	-	-	-	-	18	0	
65	Transmission by Others		p321.96.b	-	(2,265)	(2,265)	(2,265)	(2,265)	(2,265)	(2,265)	(2,265)	(2,265)	(2,265)	(2,265)	(2,265)	(2,265)	(27,175)	0	

Wages & Salary

				Previous Year	Current Year														
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Totals	Non-electric Portion	Details
4	Total Wage Expense	(Note A)	p354.28b/Trans. Wksht														643,394	0	
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht														89,022	0	
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht														46,344	0	
2	Generator Step-Ups		Trans. Wksht														15	0	

Specific identification

Transmission / Non-transmission Cost Support

				Previous Year	Current Year														
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-transmission Related	Details
30	Plant Held for Future Use (Including Land)	(Notes C & Q)	p214.47.d	15,977	15,977	15,977	15,977	15,977	15,977	15,977	15,977	15,977	15,977	15,977	15,977	15,977	15,977	11,464	Specific identification based on plant records. The following plant investments are included:
																Form 1 Amount	Transmission Related	Non-transmission Related	
																15,977	4,513	11,464	Enter Details

EPRI Dues Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5	$3,734	3,734	See Form 1

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Attachment 5 - Cost Support
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Attachment 10

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5	$ 33,057	245	32,812	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		245		

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5	5,517	-	5,517	

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				Va	NC	Wva			Enter Calculation
132	SIT=State Income Tax Rate or Composite	(Note I)		5.60%	0.09%	0.16%			5.85%

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Education & Outreach	Other		Details
	Directly Assigned A&G							
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	5,517	-	5,517	-	Informing public about transmission operations including service quality.

Excluded Plant Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions		0	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			Includes only the costs of any Interconnection Facilities constructed for VEPCO's own Generating Facilities after March 15, 2000 in accordance with Order 2003.	0	General Description of the Facilities
						None
						Add more lines if necessary

Instructions:

1 Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process

2 If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:

		Example
A	Total investment in substation	1,000,000
B	Identifiable investment in Transmission (provide workpapers)	500,000
C	Identifiable investment in Distribution (provide workpapers)	400,000
D	Amount to be excluded (A x (C / (B + C)))	444,444

Transmission Related Account 242 Reserves

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Allocation	Transmission Related		Details
47	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)			Enter $	Enter $			Amount		
	Directly Assignable to Transmission			$ 16,995	$ 14,934	$ 15,964	100%	15,964		
	Labor Related, General plant related or Common Plant related			$ 573	$ 956	$ 765	8.357%	64		
	Plant Related			$ 5,433	$ 5,404	$ 5,418	21.38%	1,158		
	Other			$ 180,581	$ 110,030	$ 145,305	0.00%	-		
	Total Transmission Related Reserves			$ -	$ -	$ -		17,187	To line 47	

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance Before Exclusion	Fixed Prepayments Exclusion Amount ^{1}			To Line 48	Description of the Prepayments
48	Prepayments										
	Wages & Salary Allocator								8.357%		
	Pension Liabilities, if any, in Account 242			$ 14	$ 7			$ 11	8.357%	1	
				$ -	$ -			$ -			Instruction: If the Prepayments Account 165 Beginning or End of Year Balance does not agree with the Form 1 Reference, enter below a note explaining the difference.
	Prepayments Account 165		p111.57d&c	$ 26,419	$ 29,415	$ 27,917	$ 3,980	$ 23,937	8.357%	2,000	Projections.
	Prepaid Pensions if not included in Prepayments							$ -	8.357%	-	

^{1} The Fixed Prepayments Exclusion Amount may be changed only pursuant to a Section 205 or Section 206 proceeding.

Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Description of the Credits
	Network Credits						
							General Description of the Credits
58	Outstanding Network Credits	(Note N)	From PJM	$ -	$ -	$ -	
							None
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	$ -	$ -	$ -	Add more lines if necessary

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Attachment 5 - Cost Support
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Attachment 10

Extraordinary Property Loss

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	# of Years	Amortization	W/ interest	Amount	Number of years	Amortization
								$ -		
89									5	$ -

Interest on Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	0	Description of the Interest on the Credits
				0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT.

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	Description & PJM Documentation
	Revenue Requirement				
165	Facility Credits under Section 30.9 of the PJM OATT.			3,184	ODEC/NCEMC Transmission Charges from PJM Invoices

PJM Load Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate			Enter	
169	1 CP Peak	(Note L)	PJM Data	21,232.0	

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	349,030
	Less OPEB Current Year			32,336
	Plus: Stated OPEB		Fixed (from FERC accepted § 205 Filing)	(33,499)
69	Current Year Total A&G Expenses			347,867

Interest on Long-Term Debt

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Interest on Long-Term Debt		p117.62c through 67c	513,933
	Less Interest on Short-Term Debt Included in Account 430			(2,924)
104	Total Interest on Long-Term Debt			511,009

Income Tax Adjustments

Line #s	Descriptions	Notes	Page #s & Instructions	Transmission Depreciation Expense Amount		Tax Rate		Amount to Line 136A	Beginning Year Balance	End of Year Balance	Average
	Tax Adj. for the AFUDC Equity Component of Transmission Depr. Expense	(Notes B, C)	Inst. 1, 2, below	$ 4,671	X	25.62%	=	$ 1,197			
	Amortization of Excess/Deficient Deferred Taxes -- Transmission Component										
	Amortized Excess Deferred Taxes	(Note C)	Inst. 1, 3, 4, below (Enter Negative)					$ (3,926)	$ (2,131)	$ (2,430)	$ (2,280)
	Amortized Deficient Deferred Taxes	(Note C)	Inst. 1, 3, 4, below (Enter Positive)								$ -
136A	Total Other Income Tax Adjustments to Line 136A							$ (2,729)			
47A	Unamortized Exc/Def Deferral to Line 47A										$ (2,280)

Inst. 1 The Capital Recovery Rate is the depreciation rate excluding salvage and cost of removal applicable to the included assets.

Inst. 2 Transmission Depreciation Expense Amount is (1) the gross cumulative amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function multiplied by (2) the Capital Recovery Rate (described in Instruction 1). For 2016, determine tax expense amounts for each of September through December and include only the sum of those four monthly amounts. The amount entered will be supported by work papers. Tax Rate is from Appendix A, Line 134.

Inst. 3 Upon enactment of changes in tax law, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function (separately referred to as "Exc/Def Deferral") will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Each Exc/Def Deferral will be reduced by any offsetting balance of a previous Exc/Def Deferral attributable to the same taxing authority before being multiplied by the Capital Recovery Rate in effect at the inception of the Exc/Def Deferral to determine the annual amortization amount. Amortization in the first and last years will include only the appropriate number of months. For each re-measurement of deferred taxes, the amount entered will be supported by work papers providing the Exc/Def Deferral, the amount amortized during the applicable year, and the unamortized balance at the end of the applicable year. Do not include amounts amortized prior to September 1, 2016.

Inst. 4 The Beginning Balance is the sum of the Exc/Def Deferrals less any associated amortization recognized in prior years.

Electric Plant Acquisition Adjustments Approved by FERC

				Previous Year	Current Year															
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric	Portion	Details
60A	Acquisition Adjustments Amount		Inst. 1	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	0		
60B	Accumulated Provision for Amortization of Line 60A Amount		Inst. 2	290	307	324	341	358	375	392	409	427	444	461	478	495	392	0		
90A	Amortization of Acquisition Adjustments Amount		Inst. 3														205			
45A	Accumulated Deferred Income Taxes Attributable to Acquisition Adjustments	Note 1	Inst. 4	(239)												(293)	(266)			

Inst. 1 For each month enter the amount included in FERC Account 114 attributable to the Wheeler Line Acquisition Adjustment for the applicable month.

Inst. 2 For each month enter the amount included in FERC Account 115 attributable to the Wheeler Line Acquisition Adjustment for the applicable month.

Inst. 3 For each year enter the amount of amortization included in FERC Account 406 attributable to the Wheeler Line Acquisition Adjustment but exclude the portion of any such amount that is amortized prior to the effective date..

Inst. 4 For each year enter the amount of Accumulated Deferred Income Tax ("ADIT")attributable to the Wheeler Line Acquisition Adjustment for the applicable year.

Note 1 This amount is not to be included in the ADIT allocated to transmission shown on line 45 but is to be included on line 45A only if the associated acquisition adjustment is approved by the FERC.

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service

The True-Up Adjustment component of the Formula Rate for each Rate Year beginning with 2010 shall be determined as follows:[1]

(i) Beginning with 2009, no later than June 15 of each year VEPCO 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) VEPCO 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 7 months ending July 31 of the current year and the monthly rates for the 12 months ending December 31 of the preceding year) divided by 19 months.

Each monthly rate used to calculate i shall be calculated pursuant to the Commission’s regulations at 18 C.F.R. § 35.19a.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
Fall	2007	TO populates the formula with Year 2008 estimated data
Sept	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
Sept	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
Sept	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
Sept	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
Sept	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
Sept	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
Sept	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

[1] No True-Up Adjustment will be included in the Annual Transmission Revenue Requirement for 2008 or 2009 since the 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 No. 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	Do 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.	966,221.64
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	953,288.51
C	Difference (A-B)	12,933
D	Future Value Factor (1+i)^24	1.08460
E	True-up Adjustment (C*D)	14,027

Where:
i = interest rate as described in (iii) above.

Attachment 10

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 6A - True-up Adjustment for Annual Revenue Requirements recovered under Schedule 12

The True-Up Adjustment component of the annual revenue requirement for each project included in Attachment 7 for each Rate Year beginning with 2010 shall be determined as follows:[1]

(i) Beginning with 2009, no later than June 15 of each year VEPCO shall recalculate an adjusted Annual 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) VEPCO shall determine the difference between the recalculated Annual Revenue Requirement and the Annual Revenue Requirement based on its projections (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment for each project 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 7 months ending July 31 of the current year and the monthly rates for the 12 months ending December 31 of the proceeding year) divided by 19 months.

Each monthly rate used to calculate i shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
Fall	2007	TO populates the formula with Year 2008 estimated data
Sept	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
Sept	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
Sept	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
Sept	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
Sept	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
Sept	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
Sept	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

[1] No True-Up Adjustment will be included in the annual revenue requirements for 2008 or 2009 since the Formula Rate was not in effect for 2006 or 2007. For all true-up calculations, the ATRR will be adjusted to exclude any true-up adjustment.

[2] To the extent possible, each input to the Formula Rate used to calculate the actual Annual 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 No. 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.

Attachment 10

Per FERC order in Docket No. ER08-92, the ROE is 11.4%, which includes a 50 basis point RTO membership adder as authorized by FERC to become effective January 1, 2008. Per FERC order in Docket No. _______, the ROE for each specific project identified in that order will also include either an 150 or 125 basis point transmission incentive adder as authorized by the Commission.

An Annual Revenue Requirement will not be determined in this Attachment 7 for RTEP projects that have not been identified as qualifying for an incentive and for which 100% of the cost is allocated to the Dominion zone. To the extent the cost allocation of such RTEP projects changes to be other than 100% allocated to the Dominion zone, the Annual Revenue Requirements will be determined in this Attachment 7 for such RTEP projects.

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

		Formula Line		
3	A	154	Net Plant Carrying Charge without Acquisition Adjustments and Depreciation	10.5695%
4	B	161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments and Depreciation	11.1303%
5	C		Line B less Line A	0.5607%

6 **FCR if a CIAC**

7	D	155	Net Plant Carrying Charge without Acquisition Adjustments, Depreciation, Return or Income Taxes	2.4507%

These Three Columns are Repeated to Provide Line Number References on All Pages

8 **The FCR resulting from Formula is for the rate period only.**

9 **Therefore actual revenues collected or the lack of revenues collected in other years are not applicable. Depreciation will be calculated for each project using the applicable Life input in effect during the months of each calendar year the project was in service.**

10			10	Details		**Project A**		**Project A-1**	
11	Schedule 12	(Yes or No)	11	Schedule 12	(Yes or No)	Yes	b0217	Yes	b0217
12	Life		12	Life		40	Upgrade Mt.Storm - Doubs 500 kV	40	Upgrade Mt.Storm - Doubs 500 kV
13	FCR W/O incentive	Line 3	13	FCR W/O incentive	Line 3	10.5695%		10.5695%	Replace Capacitors
14	Incentive Factor (Basis Points /100)		14	Incentive Factor (Basis Points /100)		0		0	
15	FCR W incentive L.13 +(L.14*L.5)		15	FCR W incentive L.13 +(L.14*L.5)		10.5695%		10.5695%	
16	Investment		16	Investment		1,039,321		911,807	
17	Annual Depreciation Exp		17	Annual Depreciation Exp		25,983		22,795	
18	In Service Month (1-12)		18	In Service Month (1-12)		12		7	

19			19		Invest Yr	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006	20	W / O incentive	2006								
21	W incentive	2006	21	W incentive	2006								
22	W / O incentive	2007	22	W / O incentive	2007	1,039,321	849	1,038,472					
23	W incentive	2007	23	W incentive	2007	1,039,321	849	1,038,472					
24	W / O incentive	2008	24	W / O incentive	2008	1,038,472	20,379	1,018,093					
25	W incentive	2008	25	W incentive	2008	1,038,472	20,379	1,018,093					
26	W / O incentive	2009	26	W / O incentive	2009	1,018,093	20,379	997,714					
27	W incentive	2009	27	W incentive	2009	1,018,093	20,379	997,714					
28	W / O incentive	2010	28	W / O incentive	2010	997,714	20,379	977,335					
29	W incentive	2010	29	W incentive	2010	997,714	20,379	977,335					
30	W / O incentive	2011	30	W / O incentive	2011	977,335	20,379	956,957					
31	W incentive	2011	31	W incentive	2011	977,335	20,379	956,957					
32	W / O incentive	2012	32	W / O incentive	2012	956,957	20,379	936,578					
33	W incentive	2012	33	W incentive	2012	956,957	20,379	936,578					
34	W / O incentive	2013	34	W / O incentive	2013	936,578	23,222	913,355					
35	W incentive	2013	35	W incentive	2013	936,578	23,222	913,355					
36	W / O incentive	2014	36	W / O incentive	2014	913,355	24,170	889,185		911,807	9,719	902,088	
37	W incentive	2014	37	W incentive	2014	913,355	24,170	889,185		911,807	9,719	902,088	
38	W / O incentive	2015	38	W / O incentive	2015	889,185	24,170	865,015		902,088	21,205	880,883	
39	W incentive	2015	39	W incentive	2015	889,185	24,170	865,015		902,088	21,205	880,883	
40	W / O incentive	2016	40	W / O incentive	2016	865,015	24,170	840,844		880,883	21,205	859,678	
41	W incentive	2016	41	W incentive	2016	865,015	24,170	840,844		880,883	21,205	859,678	
42	W / O incentive	2017	42	W / O incentive	2017	840,844	25,983	814,861		859,678	22,795	836,883	
43	W incentive	2017	43	W incentive	2017	840,844	25,983	814,861		859,678	22,795	836,883	
44	W / O incentive	2018	44	W / O incentive	2018	814,861	25,983	788,878		836,883	22,795	814,088	
45	W incentive	2018	45	W incentive	2018	814,861	25,983	788,878		836,883	22,795	814,088	
46	W / O incentive	2019	46	W / O incentive	2019	788,878	25,983	762,895	107,991	814,088	22,795	791,293	107,636
47	W incentive	2019	47	W incentive	2019	788,878	25,983	762,895	107,991	814,088	22,795	791,293	107,636

48 Lines continue as new rate years are added.

49

50 In the formulas used in the Columns for lines 19+ are as follows:

51 "In Service Month" is the first month during the first year that the project is placed in service or recovery is request for the project.

52 "Beginning" is the investment on line 16 for the first year and is the "Ending" for the prior year after the first year.

53 "Depreciation" is the annual depreciation in line 17 divided by twelve times the difference of 12.5 minus line 18 in the first year and line 17 thereafter.

54 "Ending" is "Beginning" less "Depreciation"

55 Revenue Requirement used for crediting is ("Beginning" plus "Ending") divided by two times line 13 times the quotient of 12.5 minus line 18 divided by 12

56 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 13 plus "Depreciation" thereafter.

57 Revenue Requirement used for charging is ("Beginning" plus "Ending") divided by two times line 15 times the quotient of 12.5 minus line 18 divided by 12

58 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 15 plus "Depreciation" thereafter.

59 Formula Logic to be copied on new lines added each year after line 25. Using 2009 as an example, the logic will be included in lines 26 and 27.

Beginning with the annual revenue requirements determined in 2009 for 2010, the annual revenue requirements based on projected costs will include a True-Up Adjustment for the previous calendar year in accordance with Attachment 6 A and as calculated in Lines A through I below.

Projected Revenue Requirements are calculated using the logic described for lines 19 + but with projected data for the indicated year.

Actual Revenue Requirements are calculated using the logic described for lines 19 + but with actual data for the indicated year.

Calendar Year — Do for Each Calendar Year beginning in 2009 for True-Up Adjustments applicable to 2010 annual revenue requirements.

A Proj Rev Req w/o Incentive PCY*	Projected Revenue Requirement without Incentive for Previous Calendar Year*	126,505		126,049
B Proj Rev Req w/ Incentive PCY*	Projected Revenue Requirement with Incentive for Previous Calendar Year*	126,505		126,049
C Actual Rev Req w/o Incentive PCY*	Actual Revenue Requirement without Incentive for Previous Calendar Year *	126,921		126,224
D Actual Rev Req w/ Incentive PCY*	Actual Revenue Requirement with Incentive for Previous Calendar Year *	126,921		126,224
E TUA w/o Int w/o Incentive PCY (C-A)	True-Up Adjustment Before Interest without Incentive for Previous Calendar Year (C-A)	416		175
F TUA w/o Int w/ Incentive PCY (B-D)	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	416		175
G Future Value Factor (1+i)^24 mo (ATT6)	Future Value Factor (1+i)^24 months from Attachment 6	1.08460		1.08460
H True-Up Adjustment w/o Incentive (E*G)	True-Up Adjustment without Incentive (E*G)	451		190
I True-Up Adjustment w/ Incentive (F*G)	True-Up Adjustment with Incentive (F*G)	451		190

TUA = True-Up Adjusment
PCY = Previous Calendar Year

* These amounts do not include any True-Up Adjustments.

Additional columns to be inserted after the last project as new projects are added to formula.

	Projected Revenue Requirement including True-up Adjustment, if applicable		
W / O incentive	W / O incentive	108,442	107,826
W incentive	W incentive	108,442	107,826

Attachment 10

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			**Project B**				**Project B-1**				**Project E**			
11	Schedule 12 (Yes or No)		Yes	b0222			Yes	b0222			Yes	B0226		
12	Life		40	Install 150 MVAR capacitor			40	Install 150 MVAR capacitor			40	Install 500/230 kV transformer at		
13	FCR W/O incentive Line 3		10.5695%	at Loudoun			10.5695%	at Loudoun - Replacement of			10.5695%	Clifton and Clifton 500 KV 150 MVAR		
14	Incentive Factor (Basis Points /100)		0				0	Circuit Breaker			0	capacitor		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		1,079,975				591,996				7,624,974			
17	Annual Depreciation Exp		26,999				14,800				190,624			
18	In Service Month (1-12)		9				4				8			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006	1,079,975	6,176	1,073,799									
21	W incentive	2006	1,079,975	6,176	1,073,799									
22	W / O incentive	2007	1,073,799	21,176	1,052,623						7,624,974	56,066	7,568,908	
23	W incentive	2007	1,073,799	21,176	1,052,623						7,624,974	56,066	7,568,908	
24	W / O incentive	2008	1,052,623	21,176	1,031,447						7,568,908	149,509	7,419,399	
25	W incentive	2008	1,052,623	21,176	1,031,447						7,568,908	149,509	7,419,399	
26	W / O incentive	2009	1,031,447	21,176	1,010,271						7,419,399	149,509	7,269,889	
27	W incentive	2009	1,031,447	21,176	1,010,271						7,419,399	149,509	7,269,889	
28	W / O incentive	2010	1,010,271	21,176	989,095						7,269,889	149,509	7,120,380	
29	W incentive	2010	1,010,271	21,176	989,095						7,269,889	149,509	7,120,380	
30	W / O incentive	2011	989,095	21,176	967,919						7,120,380	149,509	6,970,871	
31	W incentive	2011	989,095	21,176	967,919						7,120,380	149,509	6,970,871	
32	W / O incentive	2012	967,919	21,176	946,743						6,970,871	149,509	6,821,362	
33	W incentive	2012	967,919	21,176	946,743						6,970,871	149,509	6,821,362	
34	W / O incentive	2013	946,743	24,131	922,612		591,996	9,752	582,244		6,821,362	170,371	6,650,990	
35	W incentive	2013	946,743	24,131	922,612		591,996	9,752	582,244		6,821,362	170,371	6,650,990	
36	W / O incentive	2014	922,612	25,116	897,496		582,244	13,767	568,477		6,650,990	177,325	6,473,666	
37	W incentive	2014	922,612	25,116	897,496		582,244	13,767	568,477		6,650,990	177,325	6,473,666	
38	W / O incentive	2015	897,496	25,116	872,381		568,477	13,767	554,709		6,473,666	177,325	6,296,341	
39	W incentive	2015	897,496	25,116	872,381		568,477	13,767	554,709		6,473,666	177,325	6,296,341	
40	W / O incentive	2016	872,381	25,116	847,265		554,709	13,767	540,942		6,296,341	177,325	6,119,016	
41	W incentive	2016	872,381	25,116	847,265		554,709	13,767	540,942		6,296,341	177,325	6,119,016	
42	W / O incentive	2017	847,265	26,999	820,266		540,942	14,800	526,142		6,119,016	190,624	5,928,391	
43	W incentive	2017	847,265	26,999	820,266		540,942	14,800	526,142		6,119,016	190,624	5,928,391	
44	W / O incentive	2018	820,266	26,999	793,266		526,142	14,800	511,342		5,928,391	190,624	5,737,767	
45	W incentive	2018	820,266	26,999	793,266		526,142	14,800	511,342		5,928,391	190,624	5,737,767	
46	W / O incentive	2019	793,266	26,999	766,267	109,417	511,342	14,800	496,542	68,064	5,737,767	190,624	5,547,143	787,005
47	W incentive	2019	793,266	26,999	766,267	109,417	511,342	14,800	496,542	68,064	5,737,767	190,624	5,547,143	787,005
48														
49														
50														
51														
52														
53														
54														
55														
56														
57														
58														
59														
A	Proj Rev Req w/o Incentive PCY*					128,328				79,713				977,628
B	Proj Rev Req w/ Incentive PCY*					128,328				79,713				977,628
C	Actual Rev Req w/o Incentive PCY*					128,658				79,853				925,080
D	Actual Rev Req w/ Incentive PCY*					128,658				79,853				925,080
E	TUA w/o Int w/o Incentive PCY (C-A)					331				141				(52,548)
F	TUA w/o Int w/ Incentive PCY (B-D)					331				141				(52,548)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					359				152				(56,994)
I	True-Up Adjustment w/ Incentive (F*G)					359				152				(56,994)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	109,776	68,217	730,011
W incentive	109,776	68,217	730,011

Attachment 10

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

Project G-1 is labled as Project G in the 2008 and 2009 Annual Updates

10				**Project E-1**				**Project G-1**				**Project G-1A**		
11	Schedule 12	(Yes or No)	Yes	B0226			Yes	B0403			Yes	B0403		
12	Life		40	Install 500/230 kV transformer at			40	2nd Dooms 500/230 kV transformer			40	2nd Dooms 500/230 kV transformer		
13	FCR W/O incentive	Line 3	10.5695%	Clifton and Clifton 500 KV 150 MVAR			10.5695%	addition			10.5695%	addition		
14	Incentive Factor (Basis Points /100)		0	capacitor			0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		914,051				6,810,242				516,125			
17	Annual Depreciation Exp		22,851				170,256				12,903			
18	In Service Month (1-12)		10				11				4			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007					6,810,242	16,692	6,793,550					
23	W incentive	2007					6,810,242	16,692	6,793,550					
24	W / O incentive	2008					6,793,550	133,534	6,660,016					
25	W incentive	2008					6,793,550	133,534	6,660,016					
26	W / O incentive	2009					6,660,016	133,534	6,526,482					
27	W incentive	2009					6,660,016	133,534	6,526,482					
28	W / O incentive	2010					6,526,482	133,534	6,392,948					
29	W incentive	2010					6,526,482	133,534	6,392,948					
30	W / O incentive	2011					6,392,948	133,534	6,259,414					
31	W incentive	2011					6,392,948	133,534	6,259,414					
32	W / O incentive	2012					6,259,414	133,534	6,125,879					
33	W incentive	2012					6,259,414	133,534	6,125,879					
34	W / O incentive	2013					6,125,879	152,167	5,973,713					
35	W incentive	2013					6,125,879	152,167	5,973,713					
36	W / O incentive	2014					5,973,713	158,378	5,815,335					
37	W incentive	2014					5,973,713	158,378	5,815,335					
38	W / O incentive	2015					5,815,335	158,378	5,656,957					
39	W incentive	2015					5,815,335	158,378	5,656,957					
40	W / O incentive	2016	914,051	4,429	909,622		5,656,957	158,378	5,498,579		516,125	8,502	507,623	
41	W incentive	2016	914,051	4,429	909,622		5,656,957	158,378	5,498,579		516,125	8,502	507,623	
42	W / O incentive	2017	909,622	22,851	886,771		5,498,579	170,256	5,328,323		507,623	12,903	494,720	
43	W incentive	2017	909,622	22,851	886,771		5,498,579	170,256	5,328,323		507,623	12,903	494,720	
44	W / O incentive	2018	886,771	22,851	863,920		5,328,323	170,256	5,158,067		494,720	12,903	481,817	
45	W incentive	2018	886,771	22,851	863,920		5,328,323	170,256	5,158,067		494,720	12,903	481,817	
46	W / O incentive	2019	863,920	22,851	841,069	112,956	5,158,067	170,256	4,987,811	706,441	481,817	12,903	468,914	63,147
47	W incentive	2019	863,920	22,851	841,069	112,956	5,158,067	170,256	4,987,811	706,441	481,817	12,903	468,914	63,147
48														
49														
50														
51														
52														
53														
54														
55														
56														
57														
58														
59														
A	Proj Rev Req w/o Incentive PCY*					-				871,792				-
B	Proj Rev Req w/ Incentive PCY*					-				871,792				-
C	Actual Rev Req w/o Incentive PCY*					132,366				830,305				74,010
D	Actual Rev Req w/ Incentive PCY*					132,366				830,305				74,010
E	TUA w/o Int w/o Incentive PCY (C-A)					132,366				(41,487)				74,010
F	TUA w/o Int w/ Incentive PCY (B-D)					132,366				(41,487)				74,010
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					143,564				(44,997)				80,271
I	True-Up Adjustment w/ Incentive (F*G)					143,564				(44,997)				80,271

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		256,520	661,444	143,418
W incentive		256,520	661,444	143,418

Attachment 10

These Three Columns
are Repeated to Provide
Line Number
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10			**Project G-2**				**Project G-2A**				**Project H-1**			
11	Schedule 12	(Yes or No)	Yes	B0403			Yes	B0403			Yes	b0328.1		
12	Life		40	2nd Dooms 500/230 kV transformer			40	2nd Dooms 500/230 kV transformer			40	Build new Meadowbrook-Loudon 500kV circuit		
13	FCR W/O incentive	Line 3	10.5695%	addition			10.5695%	addition			10.5695%	(30 of 50 miles)		
14	Incentive Factor (Basis Points /100)		0				0				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%	Spare Transformer Addition			10.5695%	Spare Transformer Addition			11.4106%	line 2101 v11		
16	Investment		2,245,293				257,907				21,850,320			
17	Annual Depreciation Exp		56,132				6,448				546,258			
18	In Service Month (1-12)		4				4				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	2,245,293	31,185	2,214,108						21,850,320	232,070	21,618,250	
27	W incentive	2009	2,245,293	31,185	2,214,108						21,850,320	232,070	21,618,250	
28	W / O incentive	2010	2,214,108	44,025	2,170,083						21,618,250	428,438	21,189,812	
29	W incentive	2010	2,214,108	44,025	2,170,083						21,618,250	428,438	21,189,812	
30	W / O incentive	2011	2,170,083	44,025	2,126,058						21,189,812	428,438	20,761,374	
31	W incentive	2011	2,170,083	44,025	2,126,058						21,189,812	428,438	20,761,374	
32	W / O incentive	2012	2,126,058	44,025	2,082,032						20,761,374	428,438	20,332,937	
33	W incentive	2012	2,126,058	44,025	2,082,032						20,761,374	428,438	20,332,937	
34	W / O incentive	2013	2,082,032	50,168	2,031,864						20,332,937	488,220	19,844,717	
35	W incentive	2013	2,082,032	50,168	2,031,864						20,332,937	488,220	19,844,717	
36	W / O incentive	2014	2,031,864	52,216	1,979,648						19,844,717	508,147	19,336,570	
37	W incentive	2014	2,031,864	52,216	1,979,648						19,844,717	508,147	19,336,570	
38	W / O incentive	2015	1,979,648	52,216	1,927,432						19,336,570	508,147	18,828,423	
39	W incentive	2015	1,979,648	52,216	1,927,432						19,336,570	508,147	18,828,423	
40	W / O incentive	2016	1,927,432	52,216	1,875,216		257,907	4,248	253,659		18,828,423	508,147	18,320,276	
41	W incentive	2016	1,927,432	52,216	1,875,216		257,907	4,248	253,659		18,828,423	508,147	18,320,276	
42	W / O incentive	2017	1,875,216	56,132	1,819,083		253,659	6,448	247,211		18,320,276	546,258	17,774,018	
43	W incentive	2017	1,875,216	56,132	1,819,083		253,659	6,448	247,211		18,320,276	546,258	17,774,018	
44	W / O incentive	2018	1,819,083	56,132	1,762,951		247,211	6,448	240,763		17,774,018	546,258	17,227,760	
45	W incentive	2018	1,819,083	56,132	1,762,951		247,211	6,448	240,763		17,774,018	546,258	17,227,760	
46	W / O incentive	2019	1,762,951	56,132	1,706,819	239,501	240,763	6,448	234,316	31,554	17,227,760	546,258	16,681,502	2,338,281
47	W incentive	2019	1,762,951	56,132	1,706,819	239,501	240,763	6,448	234,316	31,554	17,227,760	546,258	16,681,502	2,480,891
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A	Proj Rev Req w/o Incentive PCY*					301,660				-				2,738,958
B	Proj Rev Req w/ Incentive PCY*					301,660				-				2,929,378
C	Actual Rev Req w/o Incentive PCY*					281,351				36,983				2,746,702
D	Actual Rev Req w/ Incentive PCY*					281,351				36,983				2,932,172
E	TUA w/o Int w/o Incentive PCY (C-A)					(20,309)				36,983				7,744
F	TUA w/o Int w/ Incentive PCY (B-D)					(20,309)				36,983				2,795
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					(22,027)				40,111				8,399
I	True-Up Adjustment w/ Incentive (F*G)					(22,027)				40,111				3,031

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		217,474	71,666	2,346,681
W incentive		217,474	71,666	2,483,922

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10			**Project H-2**				**Project H-3**				**Project H-4**			
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1		
12	Life		40	Build new Meadowbrook-Loudon 500kV circuit			40	Build new Meadowbrook-Loudon 500kV circuit			40	Build new Meadowbrook-Loudon 500kV circuit		
13	FCR W/O incentive	Line 3	10.5695%	(30 of 50 miles)			10.5695%	(30 of 50 miles)			10.5695%	(30 of 50 miles)		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.4106%	Line 2030 & 559 v12 & v13			11.4106%	Line 580 - Phase 1			11.4106%	Line 124		
16	Investment		45,089,209				13,581,000				11,224,282			
17	Annual Depreciation Exp		1,127,230				339,525				280,607			
18	In Service Month (1-12)		12				7				4			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	45,089,209	36,838	45,052,371									
27	W incentive	2009	45,089,209	36,838	45,052,371									
28	W / O incentive	2010	45,052,371	884,102	44,168,269		13,581,000	122,051	13,458,949		11,224,282	155,893	11,068,389	
29	W incentive	2010	45,052,371	884,102	44,168,269		13,581,000	122,051	13,458,949		11,224,282	155,893	11,068,389	
30	W / O incentive	2011	44,168,269	884,102	43,284,167		13,458,949	266,294	13,192,654		11,068,389	220,084	10,848,305	
31	W incentive	2011	44,168,269	884,102	43,284,167		13,458,949	266,294	13,192,654		11,068,389	220,084	10,848,305	
32	W / O incentive	2012	43,284,167	884,102	42,400,065		13,192,654	266,294	12,926,360		10,848,305	220,084	10,628,221	
33	W incentive	2012	43,284,167	884,102	42,400,065		13,192,654	266,294	12,926,360		10,848,305	220,084	10,628,221	
34	W / O incentive	2013	42,400,065	1,007,465	41,392,600		12,926,360	303,451	12,622,909		10,628,221	250,793	10,377,428	
35	W incentive	2013	42,400,065	1,007,465	41,392,600		12,926,360	303,451	12,622,909		10,628,221	250,793	10,377,428	
36	W / O incentive	2014	41,392,600	1,048,586	40,344,014		12,622,909	315,837	12,307,072		10,377,428	261,030	10,116,398	
37	W incentive	2014	41,392,600	1,048,586	40,344,014		12,622,909	315,837	12,307,072		10,377,428	261,030	10,116,398	
38	W / O incentive	2015	40,344,014	1,048,586	39,295,427		12,307,072	315,837	11,991,234		10,116,398	261,030	9,855,368	
39	W incentive	2015	40,344,014	1,048,586	39,295,427		12,307,072	315,837	11,991,234		10,116,398	261,030	9,855,368	
40	W / O incentive	2016	39,295,427	1,048,586	38,246,841		11,991,234	315,837	11,675,397		9,855,368	261,030	9,594,338	
41	W incentive	2016	39,295,427	1,048,586	38,246,841		11,991,234	315,837	11,675,397		9,855,368	261,030	9,594,338	
42	W / O incentive	2017	38,246,841	1,127,230	37,119,611		11,675,397	339,525	11,335,872		9,594,338	280,607	9,313,731	
43	W incentive	2017	38,246,841	1,127,230	37,119,611		11,675,397	339,525	11,335,872		9,594,338	280,607	9,313,731	
44	W / O incentive	2018	37,119,611	1,127,230	35,992,381		11,335,872	339,525	10,996,347		9,313,731	280,607	9,033,124	
45	W incentive	2018	37,119,611	1,127,230	35,992,381		11,335,872	339,525	10,996,347		9,313,731	280,607	9,033,124	
46	W / O incentive	2019	35,992,381	1,127,230	34,865,150	4,871,881	10,996,347	339,525	10,656,822	1,483,843	9,033,124	280,607	8,752,517	1,220,536
47	W incentive	2019	35,992,381	1,127,230	34,865,150	5,169,882	10,996,347	339,525	10,656,822	1,574,908	9,033,124	280,607	8,752,517	1,295,335
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A	Proj Rev Req w/o Incentive PCY*					5,706,559				1,738,013				1,429,621
B	Proj Rev Req w/ Incentive PCY*					6,104,159				1,859,409				1,529,371
C	Actual Rev Req w/o Incentive PCY*					5,721,853				1,742,379				1,433,314
D	Actual Rev Req w/ Incentive PCY*					6,109,123				1,860,622				1,530,473
E	TUA w/o Int w/o Incentive PCY (C-A)					15,294				4,365				3,693
F	TUA w/o Int w/ Incentive PCY (B-D)					4,964				1,213				1,103
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					16,588				4,735				4,006
I	True-Up Adjustment w/ Incentive (F*G)					5,384				1,316				1,196

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		4,888,469	1,488,578	1,224,541
W incentive		5,175,266	1,576,224	1,296,531

Attachment 10

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10				Project H-5				Project H-6				Project H-7		
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1		
12	Life		40	Build new Meadowbrook-Loudon 500kV circuit			40	Build new Meadowbrook-Loudon 500kV circuit			40	Build new Meadowbrook-Loudon 500kV circuit		
13	FCR W/O incentive	Line 3	10.5695%	(30 of 50 miles)			10.5695%	(30 of 50 miles)			10.5695%	(30 of 50 miles)		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.4106%	Line 114			11.4106%	Clevenger DP/580			11.4106%	Line 580 - Phase 2		
16	Investment		14,655,559				16,900,800				11,362,770			
17	Annual Depreciation Exp		366,389				422,520				284,069			
18	In Service Month (1-12)		6				9				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010	14,655,559	155,655	14,499,904		16,900,800	96,655	16,804,145		11,362,770	9,283	11,353,487	
29	W incentive	2010	14,655,559	155,655	14,499,904		16,900,800	96,655	16,804,145		11,362,770	9,283	11,353,487	
30	W / O incentive	2011	14,499,904	287,364	14,212,540		16,804,145	331,388	16,472,757		11,353,487	222,799	11,130,687	
31	W incentive	2011	14,499,904	287,364	14,212,540		16,804,145	331,388	16,472,757		11,353,487	222,799	11,130,687	
32	W / O incentive	2012	14,212,540	287,364	13,925,176		16,472,757	331,388	16,141,369		11,130,687	222,799	10,907,888	
33	W incentive	2012	14,212,540	287,364	13,925,176		16,472,757	331,388	16,141,369		11,130,687	222,799	10,907,888	
34	W / O incentive	2013	13,925,176	327,461	13,597,715		16,141,369	377,628	15,763,740		10,907,888	253,888	10,654,000	
35	W incentive	2013	13,925,176	327,461	13,597,715		16,141,369	377,628	15,763,740		10,907,888	253,888	10,654,000	
36	W / O incentive	2014	13,597,715	340,827	13,256,888		15,763,740	393,042	15,370,698		10,654,000	264,250	10,389,750	
37	W incentive	2014	13,597,715	340,827	13,256,888		15,763,740	393,042	15,370,698		10,654,000	264,250	10,389,750	
38	W / O incentive	2015	13,256,888	340,827	12,916,061		15,370,698	393,042	14,977,656		10,389,750	264,250	10,125,499	
39	W incentive	2015	13,256,888	340,827	12,916,061		15,370,698	393,042	14,977,656		10,389,750	264,250	10,125,499	
40	W / O incentive	2016	12,916,061	340,827	12,575,234		14,977,656	393,042	14,584,615		10,125,499	264,250	9,861,249	
41	W incentive	2016	12,916,061	340,827	12,575,234		14,977,656	393,042	14,584,615		10,125,499	264,250	9,861,249	
42	W / O incentive	2017	12,575,234	366,389	12,208,845		14,584,615	422,520	14,162,095		9,861,249	284,069	9,577,180	
43	W incentive	2017	12,575,234	366,389	12,208,845		14,584,615	422,520	14,162,095		9,861,249	284,069	9,577,180	
44	W / O incentive	2018	12,208,845	366,389	11,842,456		14,162,095	422,520	13,739,575		9,577,180	284,069	9,293,110	
45	W incentive	2018	12,208,845	366,389	11,842,456		14,162,095	422,520	13,739,575		9,577,180	284,069	9,293,110	
46	W / O incentive	2019	11,842,456	366,389	11,476,067	1,598,717	13,739,575	422,520	13,317,055	1,852,398	9,293,110	284,069	9,009,041	1,251,294
47	W incentive	2019	11,842,456	366,389	11,476,067	1,696,786	13,739,575	422,520	13,317,055	1,966,188	9,293,110	284,069	9,009,041	1,328,266
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A	Proj Rev Req w/o Incentive PCY*					1,872,572				2,169,681				1,465,601
B	Proj Rev Req w/ Incentive PCY*					2,003,320				2,321,333				1,568,147
C	Actual Rev Req w/o Incentive PCY*					1,877,320				2,175,028				1,469,109
D	Actual Rev Req w/ Incentive PCY*					2,004,673				2,322,742				1,568,993
E	TUA w/o Int w/o Incentive PCY (C-A)					4,748				5,347				3,508
F	TUA w/o Int w/ Incentive PCY (B-D)					1,353				1,410				847
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					5,150				5,799				3,805
I	True-Up Adjustment w/ Incentive (F*G)					1,467				1,529				918

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					1,603,867				1,858,197				1,255,099
	W incentive					1,698,253				1,967,717				1,329,184

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10			Project H-8				Project H-9				Project H-9A			
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.3			Yes	b0328.3		
12	Life		40	Build new Meadowbrook-Loudon 500kV circuit			40	Upgrade Mt Storm 500 kV Substation			40	Upgrade Mt Storm 500 kV Substation		
13	FCR W/O incentive	Line 3	10.5695%	(30 of 50 miles)			10.5695%				10.5695%	Replace Digital Fault Recorder		
14	Incentive Factor (Basis Points /100)		1.5				1.5				0			
15	FCR W incentive L.13 +(L.14*L.5)		11.4106%	Line 535			11.4106%				10.5695%			
16	Investment		95,094,562				13,617,010				224,609			
17	Annual Depreciation Exp		2,377,364				340,425				5,615			
18	In Service Month (1-12)		4				5				9			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011	95,094,562	1,320,758	93,773,804		13,617,010	166,875	13,450,135					
31	W incentive	2011	95,094,562	1,320,758	93,773,804		13,617,010	166,875	13,450,135					
32	W / O incentive	2012	93,773,804	1,864,599	91,909,205		13,450,135	267,000	13,183,135					
33	W incentive	2012	93,773,804	1,864,599	91,909,205		13,450,135	267,000	13,183,135					
34	W / O incentive	2013	91,909,205	2,124,776	89,784,429		13,183,135	304,256	12,878,879					
35	W incentive	2013	91,909,205	2,124,776	89,784,429		13,183,135	304,256	12,878,879					
36	W / O incentive	2014	89,784,429	2,211,501	87,572,928		12,878,879	316,675	12,562,204					
37	W incentive	2014	89,784,429	2,211,501	87,572,928		12,878,879	316,675	12,562,204					
38	W / O incentive	2015	87,572,928	2,211,501	85,361,426		12,562,204	316,675	12,245,529					
39	W incentive	2015	87,572,928	2,211,501	85,361,426		12,562,204	316,675	12,245,529					
40	W / O incentive	2016	85,361,426	2,211,501	83,149,925		12,245,529	316,675	11,928,855					
41	W incentive	2016	85,361,426	2,211,501	83,149,925		12,245,529	316,675	11,928,855					
42	W / O incentive	2017	83,149,925	2,377,364	80,772,561		11,928,855	340,425	11,588,429		224,609	1,638	222,971	
43	W incentive	2017	83,149,925	2,377,364	80,772,561		11,928,855	340,425	11,588,429		224,609	1,638	222,971	
44	W / O incentive	2018	80,772,561	2,377,364	78,395,197		11,588,429	340,425	11,248,004		222,971	5,615	217,356	
45	W incentive	2018	80,772,561	2,377,364	78,395,197		11,588,429	340,425	11,248,004		222,971	5,615	217,356	
46	W / O incentive	2019	78,395,197	2,377,364	76,017,833	10,537,724	11,248,004	340,425	10,907,579	1,511,295	217,356	5,615	211,741	12,229
47	W incentive	2019	78,395,197	2,377,364	76,017,833	11,187,127	11,248,004	340,425	10,907,579	1,604,473	217,356	5,615	211,741	12,229
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A	Proj Rev Req w/o Incentive PCY*					12,368,472				1,784,371				-
B	Proj Rev Req w/ Incentive PCY*					13,235,060				1,909,434				-
C	Actual Rev Req w/o Incentive PCY*					12,370,696				1,774,127				9,596
D	Actual Rev Req w/ Incentive PCY*					13,213,011				1,894,971				9,596
E	TUA w/o Int w/o Incentive PCY (C-A)					2,224				(10,243)				9,596
F	TUA w/o Int w/ Incentive PCY (B-D)					(22,049)				(14,463)				9,596
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					2,412				(11,110)				10,408
I	True-Up Adjustment w/ Incentive (F*G)					(23,914)				(15,687)				10,408

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	10,540,136	1,500,185	22,637
W incentive	11,163,212	1,588,786	22,637

Attachment 10

These Three Columns
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Line Number
References on All Pages

10			**Project H-10**				**Project I-1**				**Project I-2A**			
11	Schedule 12	(Yes or No)	Yes	b0328.4			Yes	b0329			Yes	b0329		
12	Life		40	Upgrade Loudoun 500 kV Substation			40	Carson-Suffolk 500 kV line +			40	Carson-Suffolk 500 kV line +		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%	Suffolk 500/230 # 2 transformer +			10.5695%	Suffolk 500/230 # 2 transformer +		
14	Incentive Factor (Basis Points /100)		1.5				1.5	Suffolk - Thrasher 230kV line			1.5	Suffolk - Thrasher 230kV line		
15	FCR W incentive L.13 +(L.14*L.5)		11.4106%				11.4106%				11.4106%			
16	Investment		3,123,926				2,434,850	Cost associated with below 500 kV elements.			38,926,257	Cost associated with below 500 kV elements.		
17	Annual Depreciation Exp		78,098				60,871				973,156			
18	In Service Month (1-12)		5				12				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009					2,434,850	1,989	2,432,861					
27	W incentive	2009					2,434,850	1,989	2,432,861					
28	W / O incentive	2010					2,432,861	47,742	2,385,119					
29	W incentive	2010					2,432,861	47,742	2,385,119					
30	W / O incentive	2011	3,123,926	38,283	3,085,643		2,385,119	47,742	2,337,376		38,926,257	413,432	38,512,825	
31	W incentive	2011	3,123,926	38,283	3,085,643		2,385,119	47,742	2,337,376		38,926,257	413,432	38,512,825	
32	W / O incentive	2012	3,085,643	61,253	3,024,389		2,337,376	47,742	2,289,634		38,512,825	763,260	37,749,565	
33	W incentive	2012	3,085,643	61,253	3,024,389		2,337,376	47,742	2,289,634		38,512,825	763,260	37,749,565	
34	W / O incentive	2013	3,024,389	69,800	2,954,589		2,289,634	54,404	2,235,230		37,749,565	869,761	36,879,803	
35	W incentive	2013	3,024,389	69,800	2,954,589		2,289,634	54,404	2,235,230		37,749,565	869,761	36,879,803	
36	W / O incentive	2014	2,954,589	72,649	2,881,939		2,235,230	56,624	2,178,606		36,879,803	905,262	35,974,541	
37	W incentive	2014	2,954,589	72,649	2,881,939		2,235,230	56,624	2,178,606		36,879,803	905,262	35,974,541	
38	W / O incentive	2015	2,881,939	72,649	2,809,290		2,178,606	56,624	2,121,982		35,974,541	905,262	35,069,280	
39	W incentive	2015	2,881,939	72,649	2,809,290		2,178,606	56,624	2,121,982		35,974,541	905,262	35,069,280	
40	W / O incentive	2016	2,809,290	72,649	2,736,640		2,121,982	56,624	2,065,357		35,069,280	905,262	34,164,018	
41	W incentive	2016	2,809,290	72,649	2,736,640		2,121,982	56,624	2,065,357		35,069,280	905,262	34,164,018	
42	W / O incentive	2017	2,736,640	78,098	2,658,542		2,065,357	60,871	2,004,486		34,164,018	973,156	33,190,861	
43	W incentive	2017	2,736,640	78,098	2,658,542		2,065,357	60,871	2,004,486		34,164,018	973,156	33,190,861	
44	W / O incentive	2018	2,658,542	78,098	2,580,444		2,004,486	60,871	1,943,615		33,190,861	973,156	32,217,705	
45	W incentive	2018	2,658,542	78,098	2,580,444		2,004,486	60,871	1,943,615		33,190,861	973,156	32,217,705	
46	W / O incentive	2019	2,580,444	78,098	2,502,346	346,711	1,943,615	60,871	1,882,743	263,085	32,217,705	973,156	31,244,549	4,326,985
47	W incentive	2019	2,580,444	78,098	2,502,346	368,088	1,943,615	60,871	1,882,743	279,177	32,217,705	973,156	31,244,549	4,593,883
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A	Proj Rev Req w/o Incentive PCY*					406,084				308,158				5,067,937
B	Proj Rev Req w/ Incentive PCY*					434,546				329,629				5,423,259
C	Actual Rev Req w/o Incentive PCY*					407,009				308,984				5,079,364
D	Actual Rev Req w/ Incentive PCY*					434,732				329,897				5,425,466
E	TUA w/o Int w/o Incentive PCY (C-A)					925				826				11,426
F	TUA w/o Int w/ Incentive PCY (B-D)					186				268				2,207
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					1,003				896				12,393
I	True-Up Adjustment w/ Incentive (F*G)					202				291				2,394

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		347,715	263,981	4,339,378
W incentive		368,290	279,468	4,596,277

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References on All Pages

10			**Project I-2B**				**Project J**				**Project K-1**			
11	Schedule 12	(Yes or No)	Yes	b0329			Yes	b0512			No			
12	Life		40	Carson-Suffolk 500 kV line +			40	MAPP Project -- Dominion Portion			40	Loudoun Bank # 1 transformer		
13	FCR W/O incentive	Line 3	10.5695%	Suffolk 500/230 # 2 transformer +			10.5695%				10.5695%	replacement		
14	Incentive Factor (Basis Points /100)		1.5	Suffolk - Thrasher 230kV line			1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.4106%				11.4106%				11.4106%			
16	Investment		163,415,144	Cost associated with Regional Facilities							12,786,365			
17	Annual Depreciation Exp		4,085,379	and Necessary Lower Voltage Facilities.			-				319,659			
18	In Service Month (1-12)		5								12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009									12,786,365	10,446	12,775,919	
27	W incentive	2009									12,786,365	10,446	12,775,919	
28	W / O incentive	2010									12,775,919	250,713	12,525,206	
29	W incentive	2010									12,775,919	250,713	12,525,206	
30	W / O incentive	2011	163,415,144	2,002,637	161,412,507						12,525,206	250,713	12,274,493	
31	W incentive	2011	163,415,144	2,002,637	161,412,507						12,525,206	250,713	12,274,493	
32	W / O incentive	2012	161,412,507	3,204,219	158,208,289		-	-	-		12,274,493	250,713	12,023,780	
33	W incentive	2012	161,412,507	3,204,219	158,208,289		-	-	-		12,274,493	250,713	12,023,780	
34	W / O incentive	2013	158,208,289	3,651,319	154,556,970		-	-	-		12,023,780	285,696	11,738,083	
35	W incentive	2013	158,208,289	3,651,319	154,556,970		-	-	-		12,023,780	285,696	11,738,083	
36	W / O incentive	2014	154,556,970	3,800,352	150,756,618		-	-	-		11,738,083	297,357	11,440,726	
37	W incentive	2014	154,556,970	3,800,352	150,756,618		-	-	-		11,738,083	297,357	11,440,726	
38	W / O incentive	2015	150,756,618	3,800,352	146,956,266		-	-	-		11,440,726	297,357	11,143,369	
39	W incentive	2015	150,756,618	3,800,352	146,956,266		-	-	-		11,440,726	297,357	11,143,369	
40	W / O incentive	2016	146,956,266	3,800,352	143,155,914		-	-	-		11,143,369	297,357	10,846,011	
41	W incentive	2016	146,956,266	3,800,352	143,155,914		-	-	-		11,143,369	297,357	10,846,011	
42	W / O incentive	2017	143,155,914	4,085,379	139,070,535		-	-	-		10,846,011	319,659	10,526,352	
43	W incentive	2017	143,155,914	4,085,379	139,070,535		-	-	-		10,846,011	319,659	10,526,352	
44	W / O incentive	2018	139,070,535	4,085,379	134,985,156		-	-	-		10,526,352	319,659	10,206,693	
45	W incentive	2018	139,070,535	4,085,379	134,985,156		-	-	-		10,526,352	319,659	10,206,693	
46	W / O incentive	2019	134,985,156	4,085,379	130,899,778	18,136,762	-	-	-	-	10,206,693	319,659	9,887,034	1,381,565
47	W incentive	2019	134,985,156	4,085,379	130,899,778	19,254,974	-	-	-	-	10,206,693	319,659	9,887,034	1,466,071
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A	Proj Rev Req w/o Incentive PCY*	21,242,216	-	1,730,350
B	Proj Rev Req w/ Incentive PCY*	22,731,041	-	1,850,911
C	Actual Rev Req w/o Incentive PCY*	21,290,966	-	1,622,599
D	Actual Rev Req w/ Incentive PCY*	22,741,185	-	1,732,421
E	TUA w/o Int w/o Incentive PCY (C-A)	48,749	-	(107,751)
F	TUA w/o Int w/ Incentive PCY (B-D)	10,143	-	(118,490)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.08460	1.08460	1.08460
H	True-Up Adjustment w/o Incentive (E*G)	52,874	-	(116,867)
I	True-Up Adjustment w/ Incentive (F*G)	11,002	-	(128,514)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	18,189,636	-	1,264,698
W incentive	19,265,976	-	1,337,557

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References on All Pages

10			Project K-2				Project L-1a				Project L-1b			
11	Schedule 12	(Yes or No)	No				No				No			
12	Life		40	Loudoun Bank # 2 transformer			40	Ox Bank # 1 transformer			40	Ox Bank # 1 transformer		
13	FCR W/O incentive	Line 3	10.5695%	replacement			10.5695%	replacement			10.5695%	spare		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.4106%				11.4106%				11.4106%			
16	Investment		14,388,779				10,056,166				2,857,132			
17	Annual Depreciation Exp		359,719				251,404				71,428			
18	In Service Month (1-12)		5				7				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009					10,056,166	90,374	9,965,792		2,857,132	2,334	2,854,798	
27	W incentive	2009					10,056,166	90,374	9,965,792		2,857,132	2,334	2,854,798	
28	W / O incentive	2010	14,388,779	176,333	14,212,446		9,965,792	197,180	9,768,612		2,854,798	56,022	2,798,776	
29	W incentive	2010	14,388,779	176,333	14,212,446		9,965,792	197,180	9,768,612		2,854,798	56,022	2,798,776	
30	W / O incentive	2011	14,212,446	282,133	13,930,313		9,768,612	197,180	9,571,433		2,798,776	56,022	2,742,753	
31	W incentive	2011	14,212,446	282,133	13,930,313		9,768,612	197,180	9,571,433		2,798,776	56,022	2,742,753	
32	W / O incentive	2012	13,930,313	282,133	13,648,180		9,571,433	197,180	9,374,253		2,742,753	56,022	2,686,731	
33	W incentive	2012	13,930,313	282,133	13,648,180		9,571,433	197,180	9,374,253		2,742,753	56,022	2,686,731	
34	W / O incentive	2013	13,648,180	321,500	13,326,680		9,374,253	224,693	9,149,560		2,686,731	63,839	2,622,892	
35	W incentive	2013	13,648,180	321,500	13,326,680		9,374,253	224,693	9,149,560		2,686,731	63,839	2,622,892	
36	W / O incentive	2014	13,326,680	334,623	12,992,057		9,149,560	233,864	8,915,695		2,622,892	66,445	2,556,447	
37	W incentive	2014	13,326,680	334,623	12,992,057		9,149,560	233,864	8,915,695		2,622,892	66,445	2,556,447	
38	W / O incentive	2015	12,992,057	334,623	12,657,434		8,915,695	233,864	8,681,831		2,556,447	66,445	2,490,002	
39	W incentive	2015	12,992,057	334,623	12,657,434		8,915,695	233,864	8,681,831		2,556,447	66,445	2,490,002	
40	W / O incentive	2016	12,657,434	334,623	12,322,811		8,681,831	233,864	8,447,967		2,490,002	66,445	2,423,557	
41	W incentive	2016	12,657,434	334,623	12,322,811		8,681,831	233,864	8,447,967		2,490,002	66,445	2,423,557	
42	W / O incentive	2017	12,322,811	359,719	11,963,092		8,447,967	251,404	8,196,562		2,423,557	71,428	2,352,129	
43	W incentive	2017	12,322,811	359,719	11,963,092		8,447,967	251,404	8,196,562		2,423,557	71,428	2,352,129	
44	W / O incentive	2018	11,963,092	359,719	11,603,373		8,196,562	251,404	7,945,158		2,352,129	71,428	2,280,701	
45	W incentive	2018	11,963,092	359,719	11,603,373		8,196,562	251,404	7,945,158		2,352,129	71,428	2,280,701	
46	W / O incentive	2019	11,603,373	359,719	11,243,653	1,567,130	7,945,158	251,404	7,693,754	1,077,883	2,280,701	71,428	2,209,272	308,713
47	W incentive	2019	11,603,373	359,719	11,243,653	1,663,216	7,945,158	251,404	7,693,754	1,143,655	2,280,701	71,428	2,209,272	327,596
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A	Proj Rev Req w/o Incentive PCY*					1,865,210				1,345,222				361,603
B	Proj Rev Req w/ Incentive PCY*					1,995,398				1,438,780				386,797
C	Actual Rev Req w/o Incentive PCY*					1,840,280				1,266,117				362,572
D	Actual Rev Req w/ Incentive PCY*					1,965,073				1,351,645				387,112
E	TUA w/o Int w/o Incentive PCY (C-A)					(24,930)				(79,105)				969
F	TUA w/o Int w/ Incentive PCY (B-D)					(30,326)				(87,135)				315
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					(27,039)				(85,797)				1,051
I	True-Up Adjustment w/ Incentive (F*G)					(32,891)				(94,506)				341

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive				1,540,091				992,086				309,764
W incentive				1,630,325				1,049,148				327,937

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References on All Pages

10			Project L-2				Project M				Project N			
11	Schedule 12 (Yes or No)		No				No				No			
12	Life		40	Ox Bank # 2 transformer			40	Yadkin Bank # 2 transformer			40	Carson Bank # 1 transformer		
13	FCR W/O incentive Line 3		10.5695%	replacement			10.5695%	replacement			10.5695%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.4106%				11.4106%				11.4106%			
16	Investment		11,501,538				16,357,858				18,431,682			
17	Annual Depreciation Exp		287,538				408,946				460,792			
18	In Service Month (1-12)		3				6				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	11,501,538	178,537	11,323,001									
27	W incentive	2009	11,501,538	178,537	11,323,001									
28	W / O incentive	2010	11,323,001	225,520	11,097,481		16,357,858	173,735	16,184,123		18,431,682	225,878	18,205,804	
29	W incentive	2010	11,323,001	225,520	11,097,481		16,357,858	173,735	16,184,123		18,431,682	225,878	18,205,804	
30	W / O incentive	2011	11,097,481	225,520	10,871,960		16,184,123	320,742	15,863,380		18,205,804	361,406	17,844,398	
31	W incentive	2011	11,097,481	225,520	10,871,960		16,184,123	320,742	15,863,380		18,205,804	361,406	17,844,398	
32	W / O incentive	2012	10,871,960	225,520	10,646,440		15,863,380	320,742	15,542,638		17,844,398	361,406	17,482,992	
33	W incentive	2012	10,871,960	225,520	10,646,440		15,863,380	320,742	15,542,638		17,844,398	361,406	17,482,992	
34	W / O incentive	2013	10,646,440	256,988	10,389,452		15,542,638	365,497	15,177,141		17,482,992	411,834	17,071,158	
35	W incentive	2013	10,646,440	256,988	10,389,452		15,542,638	365,497	15,177,141		17,482,992	411,834	17,071,158	
36	W / O incentive	2014	10,389,452	267,478	10,121,974		15,177,141	380,415	14,796,726		17,071,158	428,644	16,642,515	
37	W incentive	2014	10,389,452	267,478	10,121,974		15,177,141	380,415	14,796,726		17,071,158	428,644	16,642,515	
38	W / O incentive	2015	10,121,974	267,478	9,854,496		14,796,726	380,415	14,416,310		16,642,515	428,644	16,213,871	
39	W incentive	2015	10,121,974	267,478	9,854,496		14,796,726	380,415	14,416,310		16,642,515	428,644	16,213,871	
40	W / O incentive	2016	9,854,496	267,478	9,587,019		14,416,310	380,415	14,035,895		16,213,871	428,644	15,785,227	
41	W incentive	2016	9,854,496	267,478	9,587,019		14,416,310	380,415	14,035,895		16,213,871	428,644	15,785,227	
42	W / O incentive	2017	9,587,019	287,538	9,299,480		14,035,895	408,946	13,626,949		15,785,227	460,792	15,324,435	
43	W incentive	2017	9,587,019	287,538	9,299,480		14,035,895	408,946	13,626,949		15,785,227	460,792	15,324,435	
44	W / O incentive	2018	9,299,480	287,538	9,011,942		13,626,949	408,946	13,218,002		15,324,435	460,792	14,863,643	
45	W incentive	2018	9,299,480	287,538	9,011,942		13,626,949	408,946	13,218,002		15,324,435	460,792	14,863,643	
46	W / O incentive	2019	9,011,942	287,538	8,724,403	1,224,862	13,218,002	408,946	12,809,056	1,784,414	14,863,643	460,792	14,402,851	2,007,456
47	W incentive	2019	9,011,942	287,538	8,724,403	1,299,454	13,218,002	408,946	12,809,056	1,893,874	14,863,643	460,792	14,402,851	2,130,540
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A	Proj Rev Req w/o Incentive PCY*					1,434,767				2,119,700				2,461,126
B	Proj Rev Req w/ Incentive PCY*					1,534,405				2,267,703				2,632,908
C	Actual Rev Req w/o Incentive PCY*					1,438,931				2,095,378				2,357,354
D	Actual Rev Req w/ Incentive PCY*					1,535,979				2,237,523				2,517,211
E	TUA w/o Int w/o Incentive PCY (C-A)					4,164				(24,322)				(103,772)
F	TUA w/o Int w/ Incentive PCY (B-D)					1,573				(30,180)				(115,698)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					4,516				(26,380)				(112,551)
I	True-Up Adjustment w/ Incentive (F*G)					1,706				(32,733)				(125,485)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive					1,229,378				1,758,034				1,894,905
W incentive					1,301,161				1,861,141				2,005,055

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These Three Columns
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10			Project O				Project P				Project Q			
11	Schedule 12 (Yes or No)		No				No				No			
12	Life		40	Lexington Bank # 1 transformer			40	Dooms Bank # 7 transformer			40	Valley Bank # 1 transformer		
13	FCR W/O incentive Line 3		10.5695%	replacement			10.5695%	replacement			10.5695%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.4106%				11.4106%				11.4106%			
16	Investment		9,761,643				18,897,652				12,056,414			
17	Annual Depreciation Exp		244,041				472,441				301,410			
18	In Service Month (1-12)		12				8				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010									12,056,414	9,850	12,046,564	
29	W incentive	2010									12,056,414	9,850	12,046,564	
30	W / O incentive	2011	9,761,643	7,975	9,753,668		18,897,652	138,953	18,758,699		12,046,564	236,400	11,810,164	
31	W incentive	2011	9,761,643	7,975	9,753,668		18,897,652	138,953	18,758,699		12,046,564	236,400	11,810,164	
32	W / O incentive	2012	9,753,668	191,405	9,562,263		18,758,699	370,542	18,388,156		11,810,164	236,400	11,573,763	
33	W incentive	2012	9,753,668	191,405	9,562,263		18,758,699	370,542	18,388,156		11,810,164	236,400	11,573,763	
34	W / O incentive	2013	9,562,263	218,112	9,344,151		18,388,156	422,246	17,965,911		11,573,763	269,386	11,304,377	
35	W incentive	2013	9,562,263	218,112	9,344,151		18,388,156	422,246	17,965,911		11,573,763	269,386	11,304,377	
36	W / O incentive	2014	9,344,151	227,015	9,117,136		17,965,911	439,480	17,526,430		11,304,377	280,382	11,023,995	
37	W incentive	2014	9,344,151	227,015	9,117,136		17,965,911	439,480	17,526,430		11,304,377	280,382	11,023,995	
38	W / O incentive	2015	9,117,136	227,015	8,890,121		17,526,430	439,480	17,086,950		11,023,995	280,382	10,743,614	
39	W incentive	2015	9,117,136	227,015	8,890,121		17,526,430	439,480	17,086,950		11,023,995	280,382	10,743,614	
40	W / O incentive	2016	8,890,121	227,015	8,663,106		17,086,950	439,480	16,647,470		10,743,614	280,382	10,463,232	
41	W incentive	2016	8,890,121	227,015	8,663,106		17,086,950	439,480	16,647,470		10,743,614	280,382	10,463,232	
42	W / O incentive	2017	8,663,106	244,041	8,419,065		16,647,470	472,441	16,175,029		10,463,232	301,410	10,161,822	
43	W incentive	2017	8,663,106	244,041	8,419,065		16,647,470	472,441	16,175,029		10,463,232	301,410	10,161,822	
44	W / O incentive	2018	8,419,065	244,041	8,175,024		16,175,029	472,441	15,702,587		10,161,822	301,410	9,860,411	
45	W incentive	2018	8,419,065	244,041	8,175,024		16,175,029	472,441	15,702,587		10,161,822	301,410	9,860,411	
46	W / O incentive	2019	8,175,024	244,041	7,930,983	1,095,205	15,702,587	472,441	15,230,146	2,107,162	9,860,411	301,410	9,559,001	1,327,680
47	W incentive	2019	8,175,024	244,041	7,930,983	1,162,941	15,702,587	472,441	15,230,146	2,237,254	9,860,411	301,410	9,559,001	1,409,351
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A	Proj Rev Req w/o Incentive PCY*					1,363,586				2,467,973				1,555,069
B	Proj Rev Req w/ Incentive PCY*					1,459,381				2,641,123				1,663,875
C	Actual Rev Req w/o Incentive PCY*					1,285,435				2,473,424				1,558,791
D	Actual Rev Req w/ Incentive PCY*					1,373,211				2,642,083				1,664,773
E	TUA w/o Int w/o Incentive PCY (C-A)					(78,152)				5,451				3,722
F	TUA w/o Int w/ Incentive PCY (B-D)					(86,170)				959				898
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					(84,763)				5,912				4,037
I	True-Up Adjustment w/ Incentive (F*G)					(93,460)				1,041				974

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		1,010,442	2,113,075	1,331,717
W incentive		1,069,481	2,238,294	1,410,325

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These Three Columns
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References on All Pages

10			Project R-1				Project R-2				Project R-3			
11	Schedule 12	(Yes or No)	No	s0124			No	s0124			No	s0124		
12	Life		40	Garrisonville 230 kV UG line			40	Garrisonville 230 kV UG line			40	Garrisonville 230 kV UG line		
13	FCR W/O incentive	Line 3	10.5695%	Phase 1			10.5695%	Phase 2			10.5695%	Phase 3		
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		11.2705%				11.2705%				11.2705%			
16	Investment		91,286,696				32,204,664				13,426,813			
17	Annual Depreciation Exp		2,282,167				805,117				335,670			
18	In Service Month (1-12)		6				6				2			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010	91,286,696	969,548	90,317,148									
29	W incentive	2010	91,286,696	969,548	90,317,148									
30	W / O incentive	2011	90,317,148	1,789,935	88,527,213		32,204,664	342,043	31,862,621					
31	W incentive	2011	90,317,148	1,789,935	88,527,213		32,204,664	342,043	31,862,621					
32	W / O incentive	2012	88,527,213	1,789,935	86,737,277		31,862,621	631,464	31,231,157		13,426,813	230,362	13,196,451	
33	W incentive	2012	88,527,213	1,789,935	86,737,277		31,862,621	631,464	31,231,157		13,426,813	230,362	13,196,451	
34	W / O incentive	2013	86,737,277	2,039,694	84,697,584		31,231,157	719,575	30,511,582		13,196,451	300,006	12,896,445	
35	W incentive	2013	86,737,277	2,039,694	84,697,584		31,231,157	719,575	30,511,582		13,196,451	300,006	12,896,445	
36	W / O incentive	2014	84,697,584	2,122,946	82,574,637		30,511,582	748,946	29,762,636		12,896,445	312,251	12,584,193	
37	W incentive	2014	84,697,584	2,122,946	82,574,637		30,511,582	748,946	29,762,636		12,896,445	312,251	12,584,193	
38	W / O incentive	2015	82,574,637	2,122,946	80,451,691		29,762,636	748,946	29,013,690		12,584,193	312,251	12,271,942	
39	W incentive	2015	82,574,637	2,122,946	80,451,691		29,762,636	748,946	29,013,690		12,584,193	312,251	12,271,942	
40	W / O incentive	2016	80,451,691	2,122,946	78,328,744		29,013,690	748,946	28,264,745		12,271,942	312,251	11,959,690	
41	W incentive	2016	80,451,691	2,122,946	78,328,744		29,013,690	748,946	28,264,745		12,271,942	312,251	11,959,690	
42	W / O incentive	2017	78,328,744	2,282,167	76,046,577		28,264,745	805,117	27,459,628		11,959,690	335,670	11,624,020	
43	W incentive	2017	78,328,744	2,282,167	76,046,577		28,264,745	805,117	27,459,628		11,959,690	335,670	11,624,020	
44	W / O incentive	2018	76,046,577	2,282,167	73,764,410		27,459,628	805,117	26,654,512		11,624,020	335,670	11,288,350	
45	W incentive	2018	76,046,577	2,282,167	73,764,410		27,459,628	805,117	26,654,512		11,624,020	335,670	11,288,350	
46	W / O incentive	2019	73,764,410	2,282,167	71,482,242	9,958,106	26,654,512	805,117	25,849,395	3,579,823	11,288,350	335,670	10,952,679	1,511,056
47	W incentive	2019	73,764,410	2,282,167	71,482,242	10,467,150	26,654,512	805,117	25,849,395	3,763,832	11,288,350	335,670	10,952,679	1,589,003
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A	Proj Rev Req w/o Incentive PCY*	11,663,894	4,192,831	1,769,753
B	Proj Rev Req w/ Incentive PCY*	12,342,565	4,437,803	1,873,429
C	Actual Rev Req w/o Incentive PCY*	11,693,468	4,202,284	1,773,422
D	Actual Rev Req w/ Incentive PCY*	12,354,516	4,440,900	1,874,409
E	TUA w/o Int w/o Incentive PCY (C-A)	29,574	9,453	3,669
F	TUA w/o Int w/ Incentive PCY (B-D)	11,950	3,097	980
G	Future Value Factor (1+i)^24 mo (ATT6)	1.08460	1.08460	1.08460
H	True-Up Adjustment w/o Incentive (E*G)	32,076	10,253	3,979
I	True-Up Adjustment w/ Incentive (F*G)	12,961	3,359	1,063

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	9,990,182	3,590,076	1,515,035
W incentive	10,480,111	3,767,192	1,590,067

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References on All Pages

10			Project S-1				Project S-2				Project T-1			
11	Schedule 12	(Yes or No)	No	s0133			No	s0133			Yes	b0768		
12	Life		40	Pleasant View Hamilton 230kV			40	Pleasant View Hamilton 230kV			40	Glen Carlyn Line 251 GIB substation project		
13	FCR W/O incentive	Line 3	10.5695%	transmission line			10.5695%	transmission line			10.5695%			
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25	Loop Line 251 Idylwood -- Arlington into		
15	FCR W incentive L.13 +(L.14*L.5)		11.2705%				11.2705%				11.2705%	the GIS sub		
16	Investment		84,131,836				1,301,988				205,578			
17	Annual Depreciation Exp		2,103,296				32,550				5,139			
18	In Service Month (1-12)		10				2				6			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010	84,131,836	343,676	83,788,160						205,578	2,183	203,395	
29	W incentive	2010	84,131,836	343,676	83,788,160						205,578	2,183	203,395	
30	W / O incentive	2011	83,788,160	1,649,644	82,138,516		1,301,988	22,338	1,279,650		203,395	4,031	199,364	
31	W incentive	2011	83,788,160	1,649,644	82,138,516		1,301,988	22,338	1,279,650		203,395	4,031	199,364	
32	W / O incentive	2012	82,138,516	1,649,644	80,488,873		1,279,650	25,529	1,254,121		199,364	4,031	195,333	
33	W incentive	2012	82,138,516	1,649,644	80,488,873		1,279,650	25,529	1,254,121		199,364	4,031	195,333	
34	W / O incentive	2013	80,488,873	1,879,827	78,609,046		1,254,121	29,091	1,225,029		195,333	4,593	190,739	
35	W incentive	2013	80,488,873	1,879,827	78,609,046		1,254,121	29,091	1,225,029		195,333	4,593	190,739	
36	W / O incentive	2014	78,609,046	1,956,554	76,652,491		1,225,029	30,279	1,194,751		190,739	4,781	185,958	
37	W incentive	2014	78,609,046	1,956,554	76,652,491		1,225,029	30,279	1,194,751		190,739	4,781	185,958	
38	W / O incentive	2015	76,652,491	1,956,554	74,695,937		1,194,751	30,279	1,164,472		185,958	4,781	181,178	
39	W incentive	2015	76,652,491	1,956,554	74,695,937		1,194,751	30,279	1,164,472		185,958	4,781	181,178	
40	W / O incentive	2016	74,695,937	1,956,554	72,739,383		1,164,472	30,279	1,134,193		181,178	4,781	176,397	
41	W incentive	2016	74,695,937	1,956,554	72,739,383		1,164,472	30,279	1,134,193		181,178	4,781	176,397	
42	W / O incentive	2017	72,739,383	2,103,296	70,636,087		1,134,193	32,550	1,101,643		176,397	5,139	171,257	
43	W incentive	2017	72,739,383	2,103,296	70,636,087		1,134,193	32,550	1,101,643		176,397	5,139	171,257	
44	W / O incentive	2018	70,636,087	2,103,296	68,532,791		1,101,643	32,550	1,069,094		171,257	5,139	166,118	
45	W incentive	2018	70,636,087	2,103,296	68,532,791		1,101,643	32,550	1,069,094		171,257	5,139	166,118	
46	W / O incentive	2019	68,532,791	2,103,296	66,429,495	9,235,730	1,069,094	32,550	1,036,544	143,828	166,118	5,139	160,978	22,426
47	W incentive	2019	68,532,791	2,103,296	66,429,495	9,708,731	1,069,094	32,550	1,036,544	151,207	166,118	5,139	160,978	23,572
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A	Proj Rev Req w/o Incentive PCY*	10,815,832	168,459	26,267
B	Proj Rev Req w/ Incentive PCY*	11,446,037	178,288	27,796
C	Actual Rev Req w/o Incentive PCY*	10,844,005	168,855	26,334
D	Actual Rev Req w/ Incentive PCY*	11,457,949	178,429	27,822
E	TUA w/o Int w/o Incentive PCY (C-A)	28,173	395	67
F	TUA w/o Int w/ Incentive PCY (B-D)	11,913	140	27
G	Future Value Factor (1+i)^24 mo (ATT6)	1.08460	1.08460	1.08460
H	True-Up Adjustment w/o Incentive (E*G)	30,556	429	72
I	True-Up Adjustment w/ Incentive (F*G)	12,921	152	29

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	9,266,286	144,256	22,498
W incentive	9,721,651	151,359	23,601

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References on All Pages

10			**Project T-2**				**Project U-1**				**Project U-2**			
11	Schedule 12 (Yes or No)		Yes	b0768			Yes	b0453.1			Yes	b0453.2		
12	Life		40	Glen Carlyn Line 251 GIB substation project			40	Convert Remington - Sowego			40	Add Sowego - Gainsville 230 kV		
13	FCR W/O incentive Line 3		10.5695%				10.5695%	115kV to 230kV			10.5695%			
14	Incentive Factor (Basis Points /100)		1.25	Loop Line 251 Idylwood -- Arlington into			1.25				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		11.2705%	the GIS sub			11.2705%				11.2705%			
16	Investment		23,483,583				1,472,605				12,889,633			
17	Annual Depreciation Exp		587,090				36,815				322,241			
18	In Service Month (1-12)		6				9				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010					1,472,605	8,422	1,464,183					
29	W incentive	2010					1,472,605	8,422	1,464,183					
30	W / O incentive	2011	23,483,583	249,417	23,234,166		1,464,183	28,875	1,435,309					
31	W incentive	2011	23,483,583	249,417	23,234,166		1,464,183	28,875	1,435,309					
32	W / O incentive	2012	23,234,166	460,462	22,773,703		1,435,309	28,875	1,406,434		12,889,633	157,961	12,731,672	
33	W incentive	2012	23,234,166	460,462	22,773,703		1,435,309	28,875	1,406,434		12,889,633	157,961	12,731,672	
34	W / O incentive	2013	22,773,703	524,713	22,248,990		1,406,434	32,904	1,373,530		12,731,672	288,004	12,443,668	
35	W incentive	2013	22,773,703	524,713	22,248,990		1,406,434	32,904	1,373,530		12,731,672	288,004	12,443,668	
36	W / O incentive	2014	22,248,990	546,130	21,702,861		1,373,530	34,247	1,339,284		12,443,668	299,759	12,143,909	
37	W incentive	2014	22,248,990	546,130	21,702,861		1,373,530	34,247	1,339,284		12,443,668	299,759	12,143,909	
38	W / O incentive	2015	21,702,861	546,130	21,156,731		1,339,284	34,247	1,305,037		12,143,909	299,759	11,844,150	
39	W incentive	2015	21,702,861	546,130	21,156,731		1,339,284	34,247	1,305,037		12,143,909	299,759	11,844,150	
40	W / O incentive	2016	21,156,731	546,130	20,610,601		1,305,037	34,247	1,270,791		11,844,150	299,759	11,544,391	
41	W incentive	2016	21,156,731	546,130	20,610,601		1,305,037	34,247	1,270,791		11,844,150	299,759	11,544,391	
42	W / O incentive	2017	20,610,601	587,090	20,023,511		1,270,791	36,815	1,233,975		11,544,391	322,241	11,222,151	
43	W incentive	2017	20,610,601	587,090	20,023,511		1,270,791	36,815	1,233,975		11,544,391	322,241	11,222,151	
44	W / O incentive	2018	20,023,511	587,090	19,436,422		1,233,975	36,815	1,197,160		11,222,151	322,241	10,899,910	
45	W incentive	2018	20,023,511	587,090	19,436,422		1,233,975	36,815	1,197,160		11,222,151	322,241	10,899,910	
46	W / O incentive	2019	19,436,422	587,090	18,849,332	2,610,400	1,197,160	36,815	1,160,345	161,404	10,899,910	322,241	10,577,669	1,457,280
47	W incentive	2019	19,436,422	587,090	18,849,332	2,744,580	1,197,160	36,815	1,160,345	169,666	10,899,910	322,241	10,577,669	1,532,552
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A	Proj Rev Req w/o Incentive PCY*					3,057,405				189,049				1,706,751
B	Proj Rev Req w/ Incentive PCY*					3,236,038				200,061				1,806,834
C	Actual Rev Req w/o Incentive PCY*					3,064,298				189,515				1,710,175
D	Actual Rev Req w/ Incentive PCY*					3,238,297				200,241				1,807,663
E	TUA w/o Int w/o Incentive PCY (C-A)					6,893				466				3,424
F	TUA w/o Int w/ Incentive PCY (B-D)					2,259				180				829
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					7,476				505				3,714
I	True-Up Adjustment w/ Incentive (F*G)					2,450				195				899

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		2,617,877	161,909	1,460,993
W incentive		2,747,029	169,861	1,533,451

Attachment 10

These Three Columns
are Repeated to Provide
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References on All Pages

10			**Project V**				**Project W**				**Project X**			
11	Schedule 12 (Yes or No)		Yes	b0337			Yes	b0467.2			Yes	b0311		
12	Life		40	Build Lexington 230kV ring bus			40	Reconductor the Dickerson - Pleasant			40	Reconductor Idylwood to Arlington		
13	FCR W/O incentive Line 3		10.5695%				10.5695%	View 230 kV circuit			10.5695%	230 kV		
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		11.2705%				11.2705%				11.2705%			
16	Investment		6,389,531				5,249,379				3,196,608			
17	Annual Depreciation Exp		159,738				131,234				79,915			
18	In Service Month (1-12)		3				6				8			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	6,389,531	99,184	6,290,347						3,196,608	23,504	3,173,104	
27	W incentive	2009	6,389,531	99,184	6,290,347						3,196,608	23,504	3,173,104	
28	W / O incentive	2010	6,290,347	125,285	6,165,062						3,173,104	62,679	3,110,425	
29	W incentive	2010	6,290,347	125,285	6,165,062						3,173,104	62,679	3,110,425	
30	W / O incentive	2011	6,165,062	125,285	6,039,777		5,249,379	55,753	5,193,626		3,110,425	62,679	3,047,746	
31	W incentive	2011	6,165,062	125,285	6,039,777		5,249,379	55,753	5,193,626		3,110,425	62,679	3,047,746	
32	W / O incentive	2012	6,039,777	125,285	5,914,492		5,193,626	102,929	5,090,697		3,047,746	62,679	2,985,068	
33	W incentive	2012	6,039,777	125,285	5,914,492		5,193,626	102,929	5,090,697		3,047,746	62,679	2,985,068	
34	W / O incentive	2013	5,914,492	142,767	5,771,726		5,090,697	117,291	4,973,406		2,985,068	71,424	2,913,643	
35	W incentive	2013	5,914,492	142,767	5,771,726		5,090,697	117,291	4,973,406		2,985,068	71,424	2,913,643	
36	W / O incentive	2014	5,771,726	148,594	5,623,132		4,973,406	122,079	4,851,327		2,913,643	74,340	2,839,304	
37	W incentive	2014	5,771,726	148,594	5,623,132		4,973,406	122,079	4,851,327		2,913,643	74,340	2,839,304	
38	W / O incentive	2015	5,623,132	148,594	5,474,538		4,851,327	122,079	4,729,248		2,839,304	74,340	2,764,964	
39	W incentive	2015	5,623,132	148,594	5,474,538		4,851,327	122,079	4,729,248		2,839,304	74,340	2,764,964	
40	W / O incentive	2016	5,474,538	148,594	5,325,945		4,729,248	122,079	4,607,170		2,764,964	74,340	2,690,624	
41	W incentive	2016	5,474,538	148,594	5,325,945		4,729,248	122,079	4,607,170		2,764,964	74,340	2,690,624	
42	W / O incentive	2017	5,325,945	159,738	5,166,206		4,607,170	131,234	4,475,935		2,690,624	79,915	2,610,709	
43	W incentive	2017	5,325,945	159,738	5,166,206		4,607,170	131,234	4,475,935		2,690,624	79,915	2,610,709	
44	W / O incentive	2018	5,166,206	159,738	5,006,468		4,475,935	131,234	4,344,701		2,610,709	79,915	2,530,794	
45	W incentive	2018	5,166,206	159,738	5,006,468		4,475,935	131,234	4,344,701		2,610,709	79,915	2,530,794	
46	W / O incentive	2019	5,006,468	159,738	4,846,730	680,456	4,344,701	131,234	4,213,466	583,513	2,530,794	79,915	2,450,879	343,185
47	W incentive	2019	5,006,468	159,738	4,846,730	714,989	4,344,701	131,234	4,213,466	613,507	2,530,794	79,915	2,450,879	360,644
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A	Proj Rev Req w/o Incentive PCY*	797,066	683,434	401,988
B	Proj Rev Req w/ Incentive PCY*	843,194	723,364	425,294
C	Actual Rev Req w/o Incentive PCY*	799,379	684,975	403,104
D	Actual Rev Req w/ Incentive PCY*	844,308	723,869	425,805
E	TUA w/o Int w/o Incentive PCY (C-A)	2,313	1,541	1,117
F	TUA w/o Int w/ Incentive PCY (B-D)	1,114	505	511
G	Future Value Factor (1+i)^24 mo (ATT6)	1.08460	1.08460	1.08460
H	True-Up Adjustment w/o Incentive (E*G)	2,509	1,671	1,211
I	True-Up Adjustment w/ Incentive (F*G)	1,208	548	554

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	682,965	585,184	344,396
W incentive	716,197	614,054	361,198

Attachment 10

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References on All Pages

10			Project AA - 1				Project AA - 1B				Project AB-2			
11	Schedule 12	(Yes or No)	Yes	b0231			Yes	b0231			Yes	b0456		
12	Life		40	Install 500 kV breakers and			40	Install 500 kV breakers and			40	Re-Conductor 9.4 miles of Edinburg -		
13	FCR W/O incentive	Line 3	10.5695%	500 kV bus work at Suffolk			10.5695%	500 kV bus work at Suffolk - Replacement			10.5695%	Mt. Jackson 115 kV		
14	Incentive Factor (Basis Points /100)		0				0	of bushings			0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		21,905,733				817,260				4,839,985			
17	Annual Depreciation Exp		547,643				20,432				121,000			
18	In Service Month (1-12)		11				11				11			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	21,905,733	53,691	21,852,042						4,839,985	11,863	4,828,122	
27	W incentive	2009	21,905,733	53,691	21,852,042						4,839,985	11,863	4,828,122	
28	W / O incentive	2010	21,852,042	429,524	21,422,518						4,828,122	94,902	4,733,221	
29	W incentive	2010	21,852,042	429,524	21,422,518						4,828,122	94,902	4,733,221	
30	W / O incentive	2011	21,422,518	429,524	20,992,994						4,733,221	94,902	4,638,319	
31	W incentive	2011	21,422,518	429,524	20,992,994						4,733,221	94,902	4,638,319	
32	W / O incentive	2012	20,992,994	429,524	20,563,470						4,638,319	94,902	4,543,417	
33	W incentive	2012	20,992,994	429,524	20,563,470						4,638,319	94,902	4,543,417	
34	W / O incentive	2013	20,563,470	489,458	20,074,012						4,543,417	108,144	4,435,274	
35	W incentive	2013	20,563,470	489,458	20,074,012						4,543,417	108,144	4,435,274	
36	W / O incentive	2014	20,074,012	509,436	19,564,577						4,435,274	112,558	4,322,716	
37	W incentive	2014	20,074,012	509,436	19,564,577						4,435,274	112,558	4,322,716	
38	W / O incentive	2015	19,564,577	509,436	19,055,141						4,322,716	112,558	4,210,158	
39	W incentive	2015	19,564,577	509,436	19,055,141						4,322,716	112,558	4,210,158	
40	W / O incentive	2016	19,055,141	509,436	18,545,705						4,210,158	112,558	4,097,600	
41	W incentive	2016	19,055,141	509,436	18,545,705						4,210,158	112,558	4,097,600	
42	W / O incentive	2017	18,545,705	547,643	17,998,062		817,260	2,554	814,706		4,097,600	121,000	3,976,601	
43	W incentive	2017	18,545,705	547,643	17,998,062		817,260	2,554	814,706		4,097,600	121,000	3,976,601	
44	W / O incentive	2018	17,998,062	547,643	17,450,419		814,706	20,432	794,275		3,976,601	121,000	3,855,601	
45	W incentive	2018	17,998,062	547,643	17,450,419		814,706	20,432	794,275		3,976,601	121,000	3,855,601	
46	W / O incentive	2019	17,450,419	547,643	16,902,775	2,363,128	794,275	20,432	773,843	103,303	3,855,601	121,000	3,734,601	522,124
47	W incentive	2019	17,450,419	547,643	16,902,775	2,363,128	794,275	20,432	773,843	103,303	3,855,601	121,000	3,734,601	522,124
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A	Proj Rev Req w/o Incentive PCY*					2,768,832				-				611,579
B	Proj Rev Req w/ Incentive PCY*					2,768,832				-				611,579
C	Actual Rev Req w/o Incentive PCY*					2,775,489				14,990				613,233
D	Actual Rev Req w/ Incentive PCY*					2,775,489				14,990				613,233
E	TUA w/o Int w/o Incentive PCY (C-A)					6,657				14,990				1,654
F	TUA w/o Int w/ Incentive PCY (B-D)					6,657				14,990				1,654
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					7,220				16,258				1,794
I	True-Up Adjustment w/ Incentive (F*G)					7,220				16,258				1,794

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	2,370,348	119,561	523,918
W incentive	2,370,348	119,561	523,918

These Three Columns
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Line Number
References on All Pages

10			Project AC				Project AG				2009 Add-1			
11	Schedule 12	(Yes or No)	Yes	b0227			Yes	b0455			Yes	B0453.3		
12	Life		40	Install 500/230 kV transformer at Bristers;			40	Add 2nd Endless Caverns 230/115kV			40	Add Sowego 230/115/ kV transformer		
13	FCR W/O incentive	Line 3	10.5695%	build new 230 kV Bristers- Gainesville circuit,			10.5695%	transformer			10.5695%			
14	Incentive Factor (Basis Points /100)		0	upgrade two Loudoun - Brambleton circuits			0				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				11.2705%			
16	Investment		21,117,166				3,424,618				3,355,513			
17	Annual Depreciation Exp		527,929				85,615				83,888			
18	In Service Month (1-12)		6				5				9			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	21,117,166	224,284	20,892,882		3,424,618	41,968	3,382,650		3,355,513	19,190	3,336,323	
27	W incentive	2009	21,117,166	224,284	20,892,882		3,424,618	41,968	3,382,650		3,355,513	19,190	3,336,323	
28	W / O incentive	2010	20,892,882	414,062	20,478,820		3,382,650	67,149	3,315,500		3,336,323	65,794	3,270,529	
29	W incentive	2010	20,892,882	414,062	20,478,820		3,382,650	67,149	3,315,500		3,336,323	65,794	3,270,529	
30	W / O incentive	2011	20,478,820	414,062	20,064,758		3,315,500	67,149	3,248,351		3,270,529	65,794	3,204,734	
31	W incentive	2011	20,478,820	414,062	20,064,758		3,315,500	67,149	3,248,351		3,270,529	65,794	3,204,734	
32	W / O incentive	2012	20,064,758	414,062	19,650,696		3,248,351	67,149	3,181,202		3,204,734	65,794	3,138,940	
33	W incentive	2012	20,064,758	414,062	19,650,696		3,248,351	67,149	3,181,202		3,204,734	65,794	3,138,940	
34	W / O incentive	2013	19,650,696	471,838	19,178,858		3,181,202	76,519	3,104,682		3,138,940	74,975	3,063,965	
35	W incentive	2013	19,650,696	471,838	19,178,858		3,181,202	76,519	3,104,682		3,138,940	74,975	3,063,965	
36	W / O incentive	2014	19,178,858	491,097	18,687,761		3,104,682	79,642	3,025,040		3,063,965	78,035	2,985,930	
37	W incentive	2014	19,178,858	491,097	18,687,761		3,104,682	79,642	3,025,040		3,063,965	78,035	2,985,930	
38	W / O incentive	2015	18,687,761	491,097	18,196,664		3,025,040	79,642	2,945,398		2,985,930	78,035	2,907,895	
39	W incentive	2015	18,687,761	491,097	18,196,664		3,025,040	79,642	2,945,398		2,985,930	78,035	2,907,895	
40	W / O incentive	2016	18,196,664	491,097	17,705,567		2,945,398	79,642	2,865,756		2,907,895	78,035	2,829,859	
41	W incentive	2016	18,196,664	491,097	17,705,567		2,945,398	79,642	2,865,756		2,907,895	78,035	2,829,859	
42	W / O incentive	2017	17,705,567	527,929	17,177,638		2,865,756	85,615	2,780,140		2,829,859	83,888	2,745,971	
43	W incentive	2017	17,705,567	527,929	17,177,638		2,865,756	85,615	2,780,140		2,829,859	83,888	2,745,971	
44	W / O incentive	2018	17,177,638	527,929	16,649,709		2,780,140	85,615	2,694,525		2,745,971	83,888	2,662,084	
45	W incentive	2018	17,177,638	527,929	16,649,709		2,780,140	85,615	2,694,525		2,745,971	83,888	2,662,084	
46	W / O incentive	2019	16,649,709	527,929	16,121,780	2,259,824	2,694,525	85,615	2,608,909	365,889	2,662,084	83,888	2,578,196	360,824
47	W incentive	2019	16,649,709	527,929	16,121,780	2,259,824	2,694,525	85,615	2,608,909	365,889	2,662,084	83,888	2,578,196	379,190
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A	Proj Rev Req w/o Incentive PCY*					2,647,057				428,588				422,648
B	Proj Rev Req w/ Incentive PCY*					2,647,057				428,588				447,161
C	Actual Rev Req w/o Incentive PCY*					2,654,541				429,811				423,811
D	Actual Rev Req w/ Incentive PCY*					2,654,541				429,811				447,688
E	TUA w/o Int w/o Incentive PCY (C-A)					7,484				1,222				1,164
F	TUA w/o Int w/ Incentive PCY (B-D)					7,484				1,222				527
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					8,117				1,326				1,262
I	True-Up Adjustment w/ Incentive (F*G)					8,117				1,326				571

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					2,267,941				367,215				362,086
	W incentive					2,267,941				367,215				379,761

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References on All Pages

10			**2009 Add-6**				**Project AJ**				**Project AK-1**			
11	Schedule 12	(Yes or No)	Yes	B0837			Yes	B0327			Yes	B1507		
12	Life		40	At Mt. Storm, replace the existing MOD on the 500 kV side of the transformer with a circuit breaker			40	Build 2nd Harrisonburg - Valley 230 kV			40	Rebuild Mt Storm - Doubs 500 kV		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		779,172				6,211,387				23,947,642			
17	Annual Depreciation Exp		19,479				155,285				598,691			
18	In Service Month (1-12)		6				7				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	779,172	8,276	770,896									
27	W incentive	2009	779,172	8,276	770,896									
28	W / O incentive	2010	770,896	15,278	755,619		6,211,387	55,821	6,155,566					
29	W incentive	2010	770,896	15,278	755,619		6,211,387	55,821	6,155,566					
30	W / O incentive	2011	755,619	15,278	740,341		6,155,566	121,792	6,033,774		23,947,642	19,565	23,928,077	
31	W incentive	2011	755,619	15,278	740,341		6,155,566	121,792	6,033,774		23,947,642	19,565	23,928,077	
32	W / O incentive	2012	740,341	15,278	725,063		6,033,774	121,792	5,911,982		23,928,077	469,562	23,458,515	
33	W incentive	2012	740,341	15,278	725,063		6,033,774	121,792	5,911,982		23,928,077	469,562	23,458,515	
34	W / O incentive	2013	725,063	17,410	707,653		5,911,982	138,786	5,773,196		23,458,515	535,082	22,923,433	
35	W incentive	2013	725,063	17,410	707,653		5,911,982	138,786	5,773,196		23,458,515	535,082	22,923,433	
36	W / O incentive	2014	707,653	18,120	689,533		5,773,196	144,451	5,628,745		22,923,433	556,922	22,366,512	
37	W incentive	2014	707,653	18,120	689,533		5,773,196	144,451	5,628,745		22,923,433	556,922	22,366,512	
38	W / O incentive	2015	689,533	18,120	671,413		5,628,745	144,451	5,484,294		22,366,512	556,922	21,809,590	
39	W incentive	2015	689,533	18,120	671,413		5,628,745	144,451	5,484,294		22,366,512	556,922	21,809,590	
40	W / O incentive	2016	671,413	18,120	653,292		5,484,294	144,451	5,339,843		21,809,590	556,922	21,252,668	
41	W incentive	2016	671,413	18,120	653,292		5,484,294	144,451	5,339,843		21,809,590	556,922	21,252,668	
42	W / O incentive	2017	653,292	19,479	633,813		5,339,843	155,285	5,184,559		21,252,668	598,691	20,653,977	
43	W incentive	2017	653,292	19,479	633,813		5,339,843	155,285	5,184,559		21,252,668	598,691	20,653,977	
44	W / O incentive	2018	633,813	19,479	614,334		5,184,559	155,285	5,029,274		20,653,977	598,691	20,055,286	
45	W incentive	2018	633,813	19,479	614,334		5,184,559	155,285	5,029,274		20,653,977	598,691	20,055,286	
46	W / O incentive	2019	614,334	19,479	594,854	83,382	5,029,274	155,285	4,873,989	678,648	20,055,286	598,691	19,456,595	2,686,800
47	W incentive	2019	614,334	19,479	594,854	83,382	5,029,274	155,285	4,873,989	678,648	20,055,286	598,691	19,456,595	2,686,800
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A	Proj Rev Req w/o Incentive PCY*					97,670				794,895				3,146,813
B	Proj Rev Req w/ Incentive PCY*					97,670				794,895				3,146,813
C	Actual Rev Req w/o Incentive PCY*					97,946				796,892				3,153,478
D	Actual Rev Req w/ Incentive PCY*					97,946				796,892				3,153,478
E	TUA w/o Int w/o Incentive PCY (C-A)					276				1,997				6,665
F	TUA w/o Int w/ Incentive PCY (B-D)					276				1,997				6,665
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					300				2,165				7,229
I	True-Up Adjustment w/ Incentive (F*G)					300				2,165				7,229

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive	83,682	680,814	2,694,028
	W incentive	83,682	680,814	2,694,028

Attachment 10

These Three Columns
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References on All Pages

10			Project AK-2				Project AK-3				Project AK-4			
11	Schedule 12	(Yes or No)	Yes	B1507			Yes	B1507			Yes	B1507		
12	Life		40	Rebuild Mt Storm - Doubs 500 kV			40	Rebuild Mt. Storm-Doubs 500 kV			40	Rebuild Mt. Storm-Doubs 500 kV		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		21,791,010				120,381,556				150,057,664			
17	Annual Depreciation Exp		544,775				3,009,539				3,751,442			
18	In Service Month (1-12)		5				5				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012	21,791,010	267,047	21,523,963									
33	W incentive	2012	21,791,010	267,047	21,523,963									
34	W / O incentive	2013	21,523,963	486,894	21,037,069		120,381,556	1,749,732	118,631,824					
35	W incentive	2013	21,523,963	486,894	21,037,069		120,381,556	1,749,732	118,631,824					
36	W / O incentive	2014	21,037,069	506,768	20,530,301		118,631,824	2,799,571	115,832,253		150,057,664	2,181,071	147,876,593	
37	W incentive	2014	21,037,069	506,768	20,530,301		118,631,824	2,799,571	115,832,253		150,057,664	2,181,071	147,876,593	
38	W / O incentive	2015	20,530,301	506,768	20,023,534		115,832,253	2,799,571	113,032,682		147,876,593	3,489,713	144,386,880	
39	W incentive	2015	20,530,301	506,768	20,023,534		115,832,253	2,799,571	113,032,682		147,876,593	3,489,713	144,386,880	
40	W / O incentive	2016	20,023,534	506,768	19,516,766		113,032,682	2,799,571	110,233,111		144,386,880	3,489,713	140,897,167	
41	W incentive	2016	20,023,534	506,768	19,516,766		113,032,682	2,799,571	110,233,111		144,386,880	3,489,713	140,897,167	
42	W / O incentive	2017	19,516,766	544,775	18,971,991		110,233,111	3,009,539	107,223,572		140,897,167	3,751,442	137,145,725	
43	W incentive	2017	19,516,766	544,775	18,971,991		110,233,111	3,009,539	107,223,572		140,897,167	3,751,442	137,145,725	
44	W / O incentive	2018	18,971,991	544,775	18,427,215		107,223,572	3,009,539	104,214,033		137,145,725	3,751,442	133,394,284	
45	W incentive	2018	18,971,991	544,775	18,427,215		107,223,572	3,009,539	104,214,033		137,145,725	3,751,442	133,394,284	
46	W / O incentive	2019	18,427,215	544,775	17,882,440	2,463,654	104,214,033	3,009,539	101,204,494	13,865,417	133,394,284	3,751,442	129,642,842	17,652,325
47	W incentive	2019	18,427,215	544,775	17,882,440	2,463,654	104,214,033	3,009,539	101,204,494	13,865,417	133,394,284	3,751,442	129,642,842	17,652,325
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A	Proj Rev Req w/o Incentive PCY*					2,885,406				16,238,289				20,657,724
B	Proj Rev Req w/ Incentive PCY*					2,885,406				16,238,289				20,657,724
C	Actual Rev Req w/o Incentive PCY*					2,891,195				16,266,517				20,701,984
D	Actual Rev Req w/ Incentive PCY*					2,891,195				16,266,517				20,701,984
E	TUA w/o Int w/o Incentive PCY (C-A)					5,788				28,228				44,259
F	TUA w/o Int w/ Incentive PCY (B-D)					5,788				28,228				44,259
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					6,278				30,616				48,003
I	True-Up Adjustment w/ Incentive (F*G)					6,278				30,616				48,003

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					2,469,932				13,896,034				17,700,329
	W incentive					2,469,932				13,896,034				17,700,329

These Three Columns
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10			**Project AK-5**				**Project AK-6**				**Project AL**			
11	Schedule 12	(Yes or No)	Yes	B1507			Yes	B1507			Yes	B0457		
12	Life		40	Rebuild Mt. Storm-Doubs 500 kV			40	Rebuild Mt. Storm-Doubs 500 kV			40	Replace both wave traps on		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%				10.5695%	Dooms - Lexington 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		15,394,401				515,816				108,763			
17	Annual Depreciation Exp		384,860				12,895				2,719			
18	In Service Month (1-12)		5				6				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011									108,763	89	108,674	
31	W incentive	2011									108,763	89	108,674	
32	W / O incentive	2012									108,674	2,133	106,542	
33	W incentive	2012									108,674	2,133	106,542	
34	W / O incentive	2013									106,542	2,430	104,111	
35	W incentive	2013									106,542	2,430	104,111	
36	W / O incentive	2014									104,111	2,529	101,582	
37	W incentive	2014									104,111	2,529	101,582	
38	W / O incentive	2015	15,394,401	223,756	15,170,645						101,582	2,529	99,053	
39	W incentive	2015	15,394,401	223,756	15,170,645						101,582	2,529	99,053	
40	W / O incentive	2016	15,170,645	358,009	14,812,636		515,816	6,498	509,318		99,053	2,529	96,523	
41	W incentive	2016	15,170,645	358,009	14,812,636		515,816	6,498	509,318		99,053	2,529	96,523	
42	W / O incentive	2017	14,812,636	384,860	14,427,776		509,318	12,895	496,423		96,523	2,719	93,804	
43	W incentive	2017	14,812,636	384,860	14,427,776		509,318	12,895	496,423		96,523	2,719	93,804	
44	W / O incentive	2018	14,427,776	384,860	14,042,916		496,423	12,895	483,528		93,804	2,719	91,085	
45	W incentive	2018	14,427,776	384,860	14,042,916		496,423	12,895	483,528		93,804	2,719	91,085	
46	W / O incentive	2019	14,042,916	384,860	13,658,056	1,848,790	483,528	12,895	470,632	63,320	91,085	2,719	88,366	12,203
47	W incentive	2019	14,042,916	384,860	13,658,056	1,848,790	483,528	12,895	470,632	63,320	91,085	2,719	88,366	12,203
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A	Proj Rev Req w/o Incentive PCY*					2,055,580				89,413				14,292
B	Proj Rev Req w/ Incentive PCY*					2,055,580				89,413				14,292
C	Actual Rev Req w/o Incentive PCY*					2,167,466				74,209				14,322
D	Actual Rev Req w/ Incentive PCY*					2,167,466				74,209				14,322
E	TUA w/o Int w/o Incentive PCY (C-A)					111,885				(15,204)				30
F	TUA w/o Int w/ Incentive PCY (B-D)					111,885				(15,204)				30
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					121,351				(16,490)				33
I	True-Up Adjustment w/ Incentive (F*G)					121,351				(16,490)				33

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	1,970,141	46,831	12,235
W incentive	1,970,141	46,831	12,235

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These Three Columns
are Repeated to Provide
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References on All Pages

10			Project AM				Project AO				Project AP-1			
11	Schedule 12	(Yes or No)	Yes	B0784			Yes	B1224			Yes	B1508.3		
12	Life		40	Replace wave traps on North Anna to			40	Install 2nd Clover 500/230			40	Upgrade a 115 kV shunt capacitor banks		
13	FCR W/O incentive	Line 3	10.5695%	Ladysmith 500 kV			10.5695%	kV transformer and a 150			10.5695%	at Merck and Edinburg		
14	Incentive Factor (Basis Points /100)		0				0	MVAr capacitor			0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%	Merck		
16	Investment		75,695				14,160,502				511,009			
17	Annual Depreciation Exp		1,892				354,013				12,775			
18	In Service Month (1-12)		10				4				7			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011	75,695	309	75,386									
31	W incentive	2011	75,695	309	75,386									
32	W / O incentive	2012	75,386	1,484	73,902						511,009	4,592	506,417	
33	W incentive	2012	75,386	1,484	73,902						511,009	4,592	506,417	
34	W / O incentive	2013	73,902	1,691	72,210		14,160,502	233,264	13,927,238		506,417	11,418	494,999	
35	W incentive	2013	73,902	1,691	72,210		14,160,502	233,264	13,927,238		506,417	11,418	494,999	
36	W / O incentive	2014	72,210	1,760	70,450		13,927,238	329,314	13,597,924		494,999	11,884	483,115	
37	W incentive	2014	72,210	1,760	70,450		13,927,238	329,314	13,597,924		494,999	11,884	483,115	
38	W / O incentive	2015	70,450	1,760	68,690		13,597,924	329,314	13,268,610		483,115	11,884	471,231	
39	W incentive	2015	70,450	1,760	68,690		13,597,924	329,314	13,268,610		483,115	11,884	471,231	
40	W / O incentive	2016	68,690	1,760	66,929		13,268,610	329,314	12,939,296		471,231	11,884	459,347	
41	W incentive	2016	68,690	1,760	66,929		13,268,610	329,314	12,939,296		471,231	11,884	459,347	
42	W / O incentive	2017	66,929	1,892	65,037		12,939,296	354,013	12,585,283		459,347	12,775	446,572	
43	W incentive	2017	66,929	1,892	65,037		12,939,296	354,013	12,585,283		459,347	12,775	446,572	
44	W / O incentive	2018	65,037	1,892	63,144		12,585,283	354,013	12,231,271		446,572	12,775	433,796	
45	W incentive	2018	65,037	1,892	63,144		12,585,283	354,013	12,231,271		446,572	12,775	433,796	
46	W / O incentive	2019	63,144	1,892	61,252	8,466	12,231,271	354,013	11,877,258	1,628,091	433,796	12,775	421,021	57,950
47	W incentive	2019	63,144	1,892	61,252	8,466	12,231,271	354,013	11,877,258	1,628,091	433,796	12,775	421,021	57,950
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A	Proj Rev Req w/o Incentive PCY*					9,916				1,906,724				67,870
B	Proj Rev Req w/ Incentive PCY*					9,916				1,906,724				67,870
C	Actual Rev Req w/o Incentive PCY*					9,938				1,910,087				68,003
D	Actual Rev Req w/ Incentive PCY*					9,938				1,910,087				68,003
E	TUA w/o Int w/o Incentive PCY (C-A)					21				3,363				133
F	TUA w/o Int w/ Incentive PCY (B-D)					21				3,363				133
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					23				3,648				144
I	True-Up Adjustment w/ Incentive (F*G)					23				3,648				144

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	8,490	1,631,738	58,095
W incentive	8,490	1,631,738	58,095

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These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			**Project AP-2**				**Project AQ**				**Project AR**			
11	Schedule 12	(Yes or No)	Yes	B1508.3			Yes	B1647			Yes	B1648		
12	Life		40	Upgrade a 115 kV shunt capacitor banks			40	Upgrade the name plate			40	Upgrade the name plate rating		
13	FCR W/O incentive	Line 3	10.5695%	at Merck and Edinburg			10.5695%	rating at Morrisville 500 kV			10.5695%	at Morrisville 500 kV		
14	Incentive Factor (Basis Points /100)		0				0	breaker 'H1T573' with			0	breaker 'H2T545' with		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%	Edinburg			10.5695%	50kA breaker			10.5695%	50kA breaker		
16	Investment		755,038				16,278				16,278			
17	Annual Depreciation Exp		18,876				407				407			
18	In Service Month (1-12)		2				1				1			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012	755,038	12,954	742,084									
33	W incentive	2012	755,038	12,954	742,084									
34	W / O incentive	2013	742,084	16,870	725,213		16,278	350	15,928		16,278	350	15,928	
35	W incentive	2013	742,084	16,870	725,213		16,278	350	15,928		16,278	350	15,928	
36	W / O incentive	2014	725,213	17,559	707,654		15,928	379	15,549		15,928	379	15,549	
37	W incentive	2014	725,213	17,559	707,654		15,928	379	15,549		15,928	379	15,549	
38	W / O incentive	2015	707,654	17,559	690,095		15,549	379	15,170		15,549	379	15,170	
39	W incentive	2015	707,654	17,559	690,095		15,549	379	15,170		15,549	379	15,170	
40	W / O incentive	2016	690,095	17,559	672,536		15,170	379	14,792		15,170	379	14,792	
41	W incentive	2016	690,095	17,559	672,536		15,170	379	14,792		15,170	379	14,792	
42	W / O incentive	2017	672,536	18,876	653,660		14,792	407	14,385		14,792	407	14,385	
43	W incentive	2017	672,536	18,876	653,660		14,792	407	14,385		14,792	407	14,385	
44	W / O incentive	2018	653,660	18,876	634,785		14,385	407	13,978		14,385	407	13,978	
45	W incentive	2018	653,660	18,876	634,785		14,385	407	13,978		14,385	407	13,978	
46	W / O incentive	2019	634,785	18,876	615,909	84,972	13,978	407	13,571	1,863	13,978	407	13,571	1,863
47	W incentive	2019	634,785	18,876	615,909	84,972	13,978	407	13,571	1,863	13,978	407	13,571	1,863
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A	Proj Rev Req w/o Incentive PCY*					99,520				2,182				2,182
B	Proj Rev Req w/ Incentive PCY*					99,520				2,182				2,182
C	Actual Rev Req w/o Incentive PCY*					99,726				2,186				2,186
D	Actual Rev Req w/ Incentive PCY*					99,726				2,186				2,186
E	TUA w/o Int w/o Incentive PCY (C-A)					206				4				4
F	TUA w/o Int w/ Incentive PCY (B-D)					206				4				4
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					224				4				4
I	True-Up Adjustment w/ Incentive (F*G)					224				4				4

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	85,196	1,867	1,867
W incentive	85,196	1,867	1,867

These Three Columns
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References on All Pages

10			**Project AS**				**Project AT**				**Project AU-1**			
11	Schedule 12	(Yes or No)	Yes	B1649			Yes	B1650			Yes	B1188.6		
12	Life		40	Replace Morrisville 500 kV			40	Replace Morrisville 500 kV			40	Install one 500/230 kV		
13	FCR W/O incentive	Line 3	10.5695%	breaker 'H1T580' with			10.5695%	breaker 'H2T569' with			10.5695%	transformer and two 230 kV breakers		
14	Incentive Factor (Basis Points /100)		0	50kA breaker			0	50kA breaker			0	at Brambleton		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		858,877				858,877				235,892			
17	Annual Depreciation Exp		21,472				21,472				5,897			
18	In Service Month (1-12)		1				1				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012									235,892	2,505	233,387	
33	W incentive	2012									235,892	2,505	233,387	
34	W / O incentive	2013	858,877	18,489	840,388		858,877	18,489	840,388		233,387	5,271	228,116	
35	W incentive	2013	858,877	18,489	840,388		858,877	18,489	840,388		233,387	5,271	228,116	
36	W / O incentive	2014	840,388	19,974	820,414		840,388	19,974	820,414		228,116	5,486	222,630	
37	W incentive	2014	840,388	19,974	820,414		840,388	19,974	820,414		228,116	5,486	222,630	
38	W / O incentive	2015	820,414	19,974	800,440		820,414	19,974	800,440		222,630	5,486	217,144	
39	W incentive	2015	820,414	19,974	800,440		820,414	19,974	800,440		222,630	5,486	217,144	
40	W / O incentive	2016	800,440	19,974	780,466		800,440	19,974	780,466		217,144	5,486	211,658	
41	W incentive	2016	800,440	19,974	780,466		800,440	19,974	780,466		217,144	5,486	211,658	
42	W / O incentive	2017	780,466	21,472	758,995		780,466	21,472	758,995		211,658	5,897	205,761	
43	W incentive	2017	780,466	21,472	758,995		780,466	21,472	758,995		211,658	5,897	205,761	
44	W / O incentive	2018	758,995	21,472	737,523		758,995	21,472	737,523		205,761	5,897	199,864	
45	W incentive	2018	758,995	21,472	737,523		758,995	21,472	737,523		205,761	5,897	199,864	
46	W / O incentive	2019	737,523	21,472	716,051	98,290	737,523	21,472	716,051	98,290	199,864	5,897	193,966	26,710
47	W incentive	2019	737,523	21,472	716,051	98,290	737,523	21,472	716,051	98,290	199,864	5,897	193,966	26,710
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A	Proj Rev Req w/o Incentive PCY*					115,113				115,113				31,283
B	Proj Rev Req w/ Incentive PCY*					115,113				115,113				31,283
C	Actual Rev Req w/o Incentive PCY*					115,323				115,323				31,345
D	Actual Rev Req w/ Incentive PCY*					115,323				115,323				31,345
E	TUA w/o Int w/o Incentive PCY (C-A)					211				211				62
F	TUA w/o Int w/ Incentive PCY (B-D)					211				211				62
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					229				229				67
I	True-Up Adjustment w/ Incentive (F*G)					229				229				67

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	98,518	98,518	26,778
W incentive	98,518	98,518	26,778

Attachment 10

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10				**Project AU-2**				**Project AV-1**				**Project AV-2**		
11	Schedule 12	(Yes or No)	Yes	B1188.6			Yes	B1188			Yes	B1188		
12	Life		40	Install one 500/230 kV			40	Build new Brambleton 500 kV three			40	Build new Brambleton 500 kV three ring bus		
13	FCR W/O incentive	Line 3	10.5695%	transformer and two 230 kV breakers			10.5695%	ring bus connected to the Loudoun			10.5695%	connected to the Loudoun to Pleasant View		
14	Incentive Factor (Basis Points /100)		0	at Brambleton			0	to Pleasant View 500 kV line			0	500 kV line		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		16,717,801				-				1,604,454			
17	Annual Depreciation Exp		417,945				-				40,111			
18	In Service Month (1-12)		12								1			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013	16,717,801	16,199	16,701,602		-	-	-					
35	W incentive	2013	16,717,801	16,199	16,701,602		-	-	-					
36	W / O incentive	2014	16,701,602	388,786	16,312,816		-	-	-		1,604,454	35,758	1,568,696	
37	W incentive	2014	16,701,602	388,786	16,312,816		-	-	-		1,604,454	35,758	1,568,696	
38	W / O incentive	2015	16,312,816	388,786	15,924,029		-	-	-		1,568,696	37,313	1,531,383	
39	W incentive	2015	16,312,816	388,786	15,924,029		-	-	-		1,568,696	37,313	1,531,383	
40	W / O incentive	2016	15,924,029	388,786	15,535,243		-	-	-		1,531,383	37,313	1,494,070	
41	W incentive	2016	15,924,029	388,786	15,535,243		-	-	-		1,531,383	37,313	1,494,070	
42	W / O incentive	2017	15,535,243	417,945	15,117,298		-	-	-		1,494,070	40,111	1,453,959	
43	W incentive	2017	15,535,243	417,945	15,117,298		-	-	-		1,494,070	40,111	1,453,959	
44	W / O incentive	2018	15,117,298	417,945	14,699,353		-	-	-		1,453,959	40,111	1,413,847	
45	W incentive	2018	15,117,298	417,945	14,699,353		-	-	-		1,453,959	40,111	1,413,847	
46	W / O incentive	2019	14,699,353	417,945	14,281,408	1,949,509	-	-	-	-	1,413,847	40,111	1,373,736	187,428
47	W incentive	2019	14,699,353	417,945	14,281,408	1,949,509	-	-	-	-	1,413,847	40,111	1,373,736	187,428
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A	Proj Rev Req w/o Incentive PCY*					2,283,071				-				221,291
B	Proj Rev Req w/ Incentive PCY*					2,283,071				-				221,291
C	Actual Rev Req w/o Incentive PCY*					2,286,639				-				219,834
D	Actual Rev Req w/ Incentive PCY*					2,286,639				-				219,834
E	TUA w/o Int w/o Incentive PCY (C-A)					3,568				-				(1,457)
F	TUA w/o Int w/ Incentive PCY (B-D)					3,568				-				(1,457)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					3,870				-				(1,580)
I	True-Up Adjustment w/ Incentive (F*G)					3,870				-				(1,580)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		1,953,379	-	185,849
W incentive		1,953,379	-	185,849

Attachment 10

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			Project AW				Project AX-1				Project AX-2			
11	Schedule 12	(Yes or No)	Yes	B1698.1			Yes	B1321			Yes	B1321		
12	Life		40	Install a 500 kV breaker at			40	Build a new 230 kV line North Anna -- Oak			40	Build a new 230 kV line North Anna -- Oak		
13	FCR W/O incentive	Line 3	10.5695%	Brambleton			10.5695%	Green and install a 224 MVA 230/115			10.5695%	Green and install a 224 MVA 230/115		
14	Incentive Factor (Basis Points /100)		0				0	kV transformer at Oak Green			0	kV transformer at Oak Green		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		-				31,009,369				6,368,620			
17	Annual Depreciation Exp		-				775,234				159,216			
18	In Service Month (1-12)						3				6			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	-	-	-		31,009,369	570,909	30,438,460		6,368,620	80,225	6,288,395	
39	W incentive	2015	-	-	-		31,009,369	570,909	30,438,460		6,368,620	80,225	6,288,395	
40	W / O incentive	2016	-	-	-		30,438,460	721,148	29,717,312		6,288,395	148,107	6,140,288	
41	W incentive	2016	-	-	-		30,438,460	721,148	29,717,312		6,288,395	148,107	6,140,288	
42	W / O incentive	2017	-	-	-		29,717,312	775,234	28,942,078		6,140,288	159,216	5,981,072	
43	W incentive	2017	-	-	-		29,717,312	775,234	28,942,078		6,140,288	159,216	5,981,072	
44	W / O incentive	2018	-	-	-		28,942,078	775,234	28,166,844		5,981,072	159,216	5,821,857	
45	W incentive	2018	-	-	-		28,942,078	775,234	28,166,844		5,981,072	159,216	5,821,857	
46	W / O incentive	2019	-	-	-	-	28,166,844	775,234	27,391,609	3,711,366	5,821,857	159,216	5,662,641	766,144
47	W incentive	2019	-	-	-	-	28,166,844	775,234	27,391,609	3,711,366	5,821,857	159,216	5,662,641	766,144
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A	Proj Rev Req w/o Incentive PCY*					-				4,466,116				897,350
B	Proj Rev Req w/ Incentive PCY*					-				4,466,116				897,350
C	Actual Rev Req w/o Incentive PCY*					-				4,351,332				898,179
D	Actual Rev Req w/ Incentive PCY*					-				4,351,332				898,179
E	TUA w/o Int w/o Incentive PCY (C-A)					-				(114,784)				829
F	TUA w/o Int w/ Incentive PCY (B-D)					-				(114,784)				829
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					-				(124,495)				899
I	True-Up Adjustment w/ Incentive (F*G)					-				(124,495)				899

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive					-				3,586,871				767,043
W incentive					-				3,586,871				767,043

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			**Project AY-1**				**Project AY-2**				**Project AZ**			
11	Schedule 12	(Yes or No)	Yes	B0756.1			Yes	B0756.1			Yes	B1797		
12	Life		40	Install two 500 kV breakers at			40	Install two 500 kV breakers at			40	Wreck and rebuild 7 miles of the		
13	FCR W/O incentive	Line 3	10.5695%	Chancellor 500 kV			10.5695%	Chancellor 500 kV			10.5695%	Dominion owned section of Cloverdale -		
14	Incentive Factor (Basis Points /100)		0				0				0	Lexington 500 kV		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		4,076,165				116,523				18,459,911			
17	Annual Depreciation Exp		101,904				2,913				461,498			
18	In Service Month (1-12)		5				12				10			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013	4,076,165	59,247	4,016,918						18,459,911	89,438	18,370,473	
35	W incentive	2013	4,076,165	59,247	4,016,918						18,459,911	89,438	18,370,473	
36	W / O incentive	2014	4,016,918	94,795	3,922,124		116,523	113	116,410		18,370,473	429,300	17,941,173	
37	W incentive	2014	4,016,918	94,795	3,922,124		116,523	113	116,410		18,370,473	429,300	17,941,173	
38	W / O incentive	2015	3,922,124	94,795	3,827,329		116,410	2,710	113,700		17,941,173	429,300	17,511,873	
39	W incentive	2015	3,922,124	94,795	3,827,329		116,410	2,710	113,700		17,941,173	429,300	17,511,873	
40	W / O incentive	2016	3,827,329	94,795	3,732,535		113,700	2,710	110,990		17,511,873	429,300	17,082,573	
41	W incentive	2016	3,827,329	94,795	3,732,535		113,700	2,710	110,990		17,511,873	429,300	17,082,573	
42	W / O incentive	2017	3,732,535	101,904	3,630,631		110,990	2,913	108,077		17,082,573	461,498	16,621,075	
43	W incentive	2017	3,732,535	101,904	3,630,631		110,990	2,913	108,077		17,082,573	461,498	16,621,075	
44	W / O incentive	2018	3,630,631	101,904	3,528,727		108,077	2,913	105,164		16,621,075	461,498	16,159,577	
45	W incentive	2018	3,630,631	101,904	3,528,727		108,077	2,913	105,164		16,621,075	461,498	16,159,577	
46	W / O incentive	2019	3,528,727	101,904	3,426,822	469,488	105,164	2,913	102,251	13,874	16,159,577	461,498	15,698,079	2,145,099
47	W incentive	2019	3,528,727	101,904	3,426,822	469,488	105,164	2,913	102,251	13,874	16,159,577	461,498	15,698,079	2,145,099
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A	Proj Rev Req w/o Incentive PCY*					549,835				16,248				2,512,148
B	Proj Rev Req w/ Incentive PCY*					549,835				16,248				2,512,148
C	Actual Rev Req w/o Incentive PCY*					550,790				16,268				2,516,199
D	Actual Rev Req w/ Incentive PCY*					550,790				16,268				2,516,199
E	TUA w/o Int w/o Incentive PCY (C-A)					956				21				4,051
F	TUA w/o Int w/ Incentive PCY (B-D)					956				21				4,051
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					1,037				22				4,394
I	True-Up Adjustment w/ Incentive (F*G)					1,037				22				4,394

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		470,525	13,897	2,149,493
W incentive		470,525	13,897	2,149,493

Attachment 10

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			Project BA				Project BB-1				Project BB-2			
11	Schedule 12	(Yes or No)	Yes	B1799			Yes	B1798			Yes	B1798		
12	Life		40	Build 150 MVAR Switched Shunt at Pleasant			40	Build a 450 MVAR SVC and 300 MVAR			40	Build a 450 MVAR SVC and 300 MVAR		
13	FCR W/O incentive	Line 3	10.5695%	View 500 kV			10.5695%	switched shunt at Loudoun 500 kV			10.5695%	switched shunt at Loudoun 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		26,047,897				3,131,641				35,293,503			
17	Annual Depreciation Exp		651,197				78,291				882,338			
18	In Service Month (1-12)		11				12				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013					3,131,641	3,035	3,128,606					
35	W incentive	2013					3,131,641	3,035	3,128,606					
36	W / O incentive	2014	26,047,897	75,721	25,972,176		3,128,606	72,829	3,055,778		35,293,503	512,987	34,780,516	
37	W incentive	2014	26,047,897	75,721	25,972,176		3,128,606	72,829	3,055,778		35,293,503	512,987	34,780,516	
38	W / O incentive	2015	25,972,176	605,765	25,366,411		3,055,778	72,829	2,982,949		34,780,516	820,779	33,959,737	
39	W incentive	2015	25,972,176	605,765	25,366,411		3,055,778	72,829	2,982,949		34,780,516	820,779	33,959,737	
40	W / O incentive	2016	25,366,411	605,765	24,760,646		2,982,949	72,829	2,910,120		33,959,737	820,779	33,138,958	
41	W incentive	2016	25,366,411	605,765	24,760,646		2,982,949	72,829	2,910,120		33,959,737	820,779	33,138,958	
42	W / O incentive	2017	24,760,646	651,197	24,109,449		2,910,120	78,291	2,831,829		33,138,958	882,338	32,256,620	
43	W incentive	2017	24,760,646	651,197	24,109,449		2,910,120	78,291	2,831,829		33,138,958	882,338	32,256,620	
44	W / O incentive	2018	24,109,449	651,197	23,458,251		2,831,829	78,291	2,753,538		32,256,620	882,338	31,374,283	
45	W incentive	2018	24,109,449	651,197	23,458,251		2,831,829	78,291	2,753,538		32,256,620	882,338	31,374,283	
46	W / O incentive	2019	23,458,251	651,197	22,807,054	3,096,208	2,753,538	78,291	2,675,247	365,189	31,374,283	882,338	30,491,945	4,151,820
47	W incentive	2019	23,458,251	651,197	22,807,054	3,096,208	2,753,538	78,291	2,675,247	365,189	31,374,283	882,338	30,491,945	4,151,820
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A	Proj Rev Req w/o Incentive PCY*					3,617,070				427,673				5,396,751
B	Proj Rev Req w/ Incentive PCY*					3,617,070				427,673				5,396,751
C	Actual Rev Req w/o Incentive PCY*					3,630,502				428,342				4,869,098
D	Actual Rev Req w/ Incentive PCY*					3,630,502				428,342				4,869,098
E	TUA w/o Int w/o Incentive PCY (C-A)					13,433				668				(527,653)
F	TUA w/o Int w/ Incentive PCY (B-D)					13,433				668				(527,653)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					14,569				725				(572,292)
I	True-Up Adjustment w/ Incentive (F*G)					14,569				725				(572,292)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		3,110,777		365,914	3,579,528
W incentive		3,110,777		365,914	3,579,528

Attachment 10

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are Repeated to Provide
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References on All Pages

10			**Project BB-3**				**Project BB-4**				**Project BB-5**			
11	Schedule 12	(Yes or No)	Yes	B1798			Yes	B1798			Yes	B1798		
12	Life		40	Build a 450 MVAR SVC and 300 MVAR			40	Build a 450 MVAR SVC and 300 MVAR			40	Build a 450 MVAR SVC and 300 MVAR		
13	FCR W/O incentive	Line 3	10.5695%	switched shunt at Loudoun 500 kV			10.5695%	switched shunt at Loudoun 500 kV			10.5695%	switched shunt at Loudoun 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		18,023,576				38,035,625				12,314,952			
17	Annual Depreciation Exp		450,589				950,891				307,874			
18	In Service Month (1-12)		6				8				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
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30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014	18,023,576	227,041	17,796,535		38,035,625	331,706	37,703,919		12,314,952	11,933	12,303,019	
37	W incentive	2014	18,023,576	227,041	17,796,535		38,035,625	331,706	37,703,919		12,314,952	11,933	12,303,019	
38	W / O incentive	2015	17,796,535	419,153	17,377,382		37,703,919	884,549	36,819,370		12,303,019	286,394	12,016,625	
39	W incentive	2015	17,796,535	419,153	17,377,382		37,703,919	884,549	36,819,370		12,303,019	286,394	12,016,625	
40	W / O incentive	2016	17,377,382	419,153	16,958,229		36,819,370	884,549	35,934,820		12,016,625	286,394	11,730,230	
41	W incentive	2016	17,377,382	419,153	16,958,229		36,819,370	884,549	35,934,820		12,016,625	286,394	11,730,230	
42	W / O incentive	2017	16,958,229	450,589	16,507,640		35,934,820	950,891	34,983,930		11,730,230	307,874	11,422,357	
43	W incentive	2017	16,958,229	450,589	16,507,640		35,934,820	950,891	34,983,930		11,730,230	307,874	11,422,357	
44	W / O incentive	2018	16,507,640	450,589	16,057,050		34,983,930	950,891	34,033,039		11,422,357	307,874	11,114,483	
45	W incentive	2018	16,507,640	450,589	16,057,050		34,983,930	950,891	34,033,039		11,422,357	307,874	11,114,483	
46	W / O incentive	2019	16,057,050	450,589	15,606,461	2,123,930	34,033,039	950,891	33,082,148	4,497,768	11,114,483	307,874	10,806,609	1,466,351
47	W incentive	2019	16,057,050	450,589	15,606,461	2,123,930	34,033,039	950,891	33,082,148	4,497,768	11,114,483	307,874	10,806,609	1,466,351
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A	Proj Rev Req w/o Incentive PCY*					2,545,209				5,197,343				1,164,601
B	Proj Rev Req w/ Incentive PCY*					2,545,209				5,197,343				1,164,601
C	Actual Rev Req w/o Incentive PCY*					2,490,795				5,274,365				1,719,343
D	Actual Rev Req w/ Incentive PCY*					2,490,795				5,274,365				1,719,343
E	TUA w/o Int w/o Incentive PCY (C-A)					(54,415)				77,021				554,742
F	TUA w/o Int w/ Incentive PCY (B-D)					(54,415)				77,021				554,742
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					(59,018)				83,537				601,672
I	True-Up Adjustment w/ Incentive (F*G)					(59,018)				83,537				601,672

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	2,064,912	4,581,305	2,068,023
W incentive	2,064,912	4,581,305	2,068,023

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			**Project BB-6**				**Project BC**				**Project BD-1**			
11	Schedule 12	(Yes or No)	Yes	B1798			Yes	B1805			Yes	B1508.1		
12	Life		40	Build a 450 MVAR SVC and 300 MVAR			40	Install a 250 MVAR SVC at the existing Mt.			40	Build a 2nd 230kV line Harrisonburg to		
13	FCR W/O incentive	Line 3	10.5695%	switched shunt at Loudoun 500 kV			10.5695%	Storm 500 kV substation			10.5695%	Endless Caverns		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		4,574,038				37,153,276				4,829,987			
17	Annual Depreciation Exp		114,351				928,832				120,750			
18	In Service Month (1-12)		1				6				10			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013									4,829,987	23,401	4,806,586	
35	W incentive	2013									4,829,987	23,401	4,806,586	
36	W / O incentive	2014					37,153,276	468,016	36,685,260		4,806,586	112,325	4,694,261	
37	W incentive	2014					37,153,276	468,016	36,685,260		4,806,586	112,325	4,694,261	
38	W / O incentive	2015	4,574,038	101,941	4,472,097		36,685,260	864,030	35,821,230		4,694,261	112,325	4,581,935	
39	W incentive	2015	4,574,038	101,941	4,472,097		36,685,260	864,030	35,821,230		4,694,261	112,325	4,581,935	
40	W / O incentive	2016	4,472,097	106,373	4,365,724		35,821,230	864,030	34,957,201		4,581,935	112,325	4,469,610	
41	W incentive	2016	4,472,097	106,373	4,365,724		35,821,230	864,030	34,957,201		4,581,935	112,325	4,469,610	
42	W / O incentive	2017	4,365,724	114,351	4,251,373		34,957,201	928,832	34,028,369		4,469,610	120,750	4,348,860	
43	W incentive	2017	4,365,724	114,351	4,251,373		34,957,201	928,832	34,028,369		4,469,610	120,750	4,348,860	
44	W / O incentive	2018	4,251,373	114,351	4,137,022		34,028,369	928,832	33,099,537		4,348,860	120,750	4,228,111	
45	W incentive	2018	4,251,373	114,351	4,137,022		34,028,369	928,832	33,099,537		4,348,860	120,750	4,228,111	
46	W / O incentive	2019	4,137,022	114,351	4,022,671	545,571	33,099,537	928,832	32,170,705	4,378,208	4,228,111	120,750	4,107,361	561,259
47	W incentive	2019	4,137,022	114,351	4,022,671	545,571	33,099,537	928,832	32,170,705	4,378,208	4,228,111	120,750	4,107,361	561,259
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A	Proj Rev Req w/o Incentive PCY*					640,280				5,127,193				657,297
B	Proj Rev Req w/ Incentive PCY*					640,280				5,127,193				657,297
C	Actual Rev Req w/o Incentive PCY*					639,682				5,134,452				658,357
D	Actual Rev Req w/ Incentive PCY*					639,682				5,134,452				658,357
E	TUA w/o Int w/o Incentive PCY (C-A)					(598)				7,259				1,060
F	TUA w/o Int w/ Incentive PCY (B-D)					(598)				7,259				1,060
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					(648)				7,873				1,150
I	True-Up Adjustment w/ Incentive (F*G)					(648)				7,873				1,150

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		544,923	4,386,081	562,409
W incentive		544,923	4,386,081	562,409

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These Three Columns
are Repeated to Provide
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References on All Pages

10			Project BD-2				Project BD-3				Project BD-4			
11	Schedule 12	(Yes or No)	Yes	B1508.1			Yes	B1508.1			Yes	B1508.1		
12	Life		40	Build a 2nd 230kV line Harrisonburg to			40	Build a 2nd 230kV line Harrisonburg to			40	Build a 2nd 230kV line Harrisonburg to		
13	FCR W/O incentive	Line 3	10.5695%	Endless Caverns			10.5695%	Endless Caverns			10.5695%	Endless Caverns		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		51,208,945				2,000,000				6,221,317			
17	Annual Depreciation Exp		1,280,224				50,000				155,533			
18	In Service Month (1-12)		9				12				6			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014	51,208,945	347,347	50,861,598		2,000,000	1,938	1,998,062					
37	W incentive	2014	51,208,945	347,347	50,861,598		2,000,000	1,938	1,998,062					
38	W / O incentive	2015	50,861,598	1,190,906	49,670,692		1,998,062	46,512	1,951,550		6,221,317	78,369	6,142,948	
39	W incentive	2015	50,861,598	1,190,906	49,670,692		1,998,062	46,512	1,951,550		6,221,317	78,369	6,142,948	
40	W / O incentive	2016	49,670,692	1,190,906	48,479,786		1,951,550	46,512	1,905,039		6,142,948	144,682	5,998,266	
41	W incentive	2016	49,670,692	1,190,906	48,479,786		1,951,550	46,512	1,905,039		6,142,948	144,682	5,998,266	
42	W / O incentive	2017	48,479,786	1,280,224	47,199,562		1,905,039	50,000	1,855,039		5,998,266	155,533	5,842,733	
43	W incentive	2017	48,479,786	1,280,224	47,199,562		1,905,039	50,000	1,855,039		5,998,266	155,533	5,842,733	
44	W / O incentive	2018	47,199,562	1,280,224	45,919,339		1,855,039	50,000	1,805,039		5,842,733	155,533	5,687,200	
45	W incentive	2018	47,199,562	1,280,224	45,919,339		1,855,039	50,000	1,805,039		5,842,733	155,533	5,687,200	
46	W / O incentive	2019	45,919,339	1,280,224	44,639,115	6,066,022	1,805,039	50,000	1,755,039	238,142	5,687,200	155,533	5,531,667	748,423
47	W incentive	2019	45,919,339	1,280,224	44,639,115	6,066,022	1,805,039	50,000	1,755,039	238,142	5,687,200	155,533	5,531,667	748,423
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A	Proj Rev Req w/o Incentive PCY*					7,059,727				278,874				794,599
B	Proj Rev Req w/ Incentive PCY*					7,059,727				278,874				794,599
C	Actual Rev Req w/o Incentive PCY*					7,113,197				279,228				877,405
D	Actual Rev Req w/ Incentive PCY*					7,113,197				279,228				877,405
E	TUA w/o Int w/o Incentive PCY (C-A)					53,470				355				82,806
F	TUA w/o Int w/ Incentive PCY (B-D)					53,470				355				82,806
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					57,993				385				89,811
I	True-Up Adjustment w/ Incentive (F*G)					57,993				385				89,811

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive				6,124,015				238,526				838,235
W incentive				6,124,015				238,526				838,235

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are Repeated to Provide
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References on All Pages

10			Project BD-5				Project BE				Project BF-1			
11	Schedule 12	(Yes or No)	Yes	B1508.1			Yes	B1508.2			Yes	B2053		
12	Life		40	Build a 2nd 230kV line Harrisonburg to			40	Install a 3rd 230 - 115 kV Tx at			40	Rebuild 28 mile line		
13	FCR W/O incentive	Line 3	10.5695%	Endless Caverns			10.5695%	Endless Caverns			10.5695%	(Altavista - Skimmer, 115kV)		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		1,165,302				11,994,009				6,782,738			
17	Annual Depreciation Exp		29,133				299,850				169,568			
18	In Service Month (1-12)		7				9				11			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014					11,994,009	81,355	11,912,654		6,782,738	19,717	6,763,021	
37	W incentive	2014					11,994,009	81,355	11,912,654		6,782,738	19,717	6,763,021	
38	W / O incentive	2015					11,912,654	278,930	11,633,724		6,763,021	157,738	6,605,283	
39	W incentive	2015					11,912,654	278,930	11,633,724		6,763,021	157,738	6,605,283	
40	W / O incentive	2016	1,165,302	12,421	1,152,881		11,633,724	278,930	11,354,793		6,605,283	157,738	6,447,545	
41	W incentive	2016	1,165,302	12,421	1,152,881		11,633,724	278,930	11,354,793		6,605,283	157,738	6,447,545	
42	W / O incentive	2017	1,152,881	29,133	1,123,749		11,354,793	299,850	11,054,943		6,447,545	169,568	6,277,976	
43	W incentive	2017	1,152,881	29,133	1,123,749		11,354,793	299,850	11,054,943		6,447,545	169,568	6,277,976	
44	W / O incentive	2018	1,123,749	29,133	1,094,616		11,054,943	299,850	10,755,093		6,277,976	169,568	6,108,408	
45	W incentive	2018	1,123,749	29,133	1,094,616		11,054,943	299,850	10,755,093		6,277,976	169,568	6,108,408	
46	W / O incentive	2019	1,094,616	29,133	1,065,483	143,289	10,755,093	299,850	10,455,243	1,420,766	6,108,408	169,568	5,938,839	806,237
47	W incentive	2019	1,094,616	29,133	1,065,483	143,289	10,755,093	299,850	10,455,243	1,420,766	6,108,408	169,568	5,938,839	806,237
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A	Proj Rev Req w/o Incentive PCY*					-				1,663,797				944,141
B	Proj Rev Req w/ Incentive PCY*					-				1,663,797				944,141
C	Actual Rev Req w/o Incentive PCY*					167,924				1,666,032				945,364
D	Actual Rev Req w/ Incentive PCY*					167,924				1,666,032				945,364
E	TUA w/o Int w/o Incentive PCY (C-A)					167,924				2,235				1,223
F	TUA w/o Int w/ Incentive PCY (B-D)					167,924				2,235				1,223
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					182,131				2,424				1,327
I	True-Up Adjustment w/ Incentive (F*G)					182,131				2,424				1,327

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					325,419				1,423,190				807,563
	W incentive					325,419				1,423,190				807,563

These Three Columns
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10			Project BF-2				Project BF-3				Project BF-4			
11	Schedule 12	(Yes or No)	Yes	B2053			Yes	B2053			Yes	B2053		
12	Life		40	Rebuild 28 mile line			40	Rebuild 28 mile line			40	Rebuild 28 mile line		
13	FCR W/O incentive	Line 3	10.5695%	(Altavista - Skimmer, 115kV)			10.5695%	(Altavista - Skimmer, 115kV)			10.5695%	(Altavista - Skimmer, 115kV)		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		23,185,930				12,489,226				1,006,355			
17	Annual Depreciation Exp		579,648				312,231				25,159			
18	In Service Month (1-12)		3				6				12			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	23,185,930	426,873	22,759,057		12,489,226	157,326	12,331,900		1,006,355	975	1,005,380	
39	W incentive	2015	23,185,930	426,873	22,759,057		12,489,226	157,326	12,331,900		1,006,355	975	1,005,380	
40	W / O incentive	2016	22,759,057	539,208	22,219,850		12,331,900	290,447	12,041,453		1,005,380	23,404	981,976	
41	W incentive	2016	22,759,057	539,208	22,219,850		12,331,900	290,447	12,041,453		1,005,380	23,404	981,976	
42	W / O incentive	2017	22,219,850	579,648	21,640,201		12,041,453	312,231	11,729,223		981,976	25,159	956,817	
43	W incentive	2017	22,219,850	579,648	21,640,201		12,041,453	312,231	11,729,223		981,976	25,159	956,817	
44	W / O incentive	2018	21,640,201	579,648	21,060,553		11,729,223	312,231	11,416,992		956,817	25,159	931,658	
45	W incentive	2018	21,640,201	579,648	21,060,553		11,729,223	312,231	11,416,992		956,817	25,159	931,658	
46	W / O incentive	2019	21,060,553	579,648	20,480,905	2,775,015	11,416,992	312,231	11,104,761	1,502,452	931,658	25,159	906,500	122,301
47	W incentive	2019	21,060,553	579,648	20,480,905	2,775,015	11,416,992	312,231	11,104,761	1,502,452	931,658	25,159	906,500	122,301
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A	Proj Rev Req w/o Incentive PCY*					3,240,526				1,699,019				134,357
B	Proj Rev Req w/ Incentive PCY*					3,240,526				1,699,019				134,357
C	Actual Rev Req w/o Incentive PCY*					3,253,522				1,761,381				143,355
D	Actual Rev Req w/ Incentive PCY*					3,253,522				1,761,381				143,355
E	TUA w/o Int w/o Incentive PCY (C-A)					12,996				62,361				8,998
F	TUA w/o Int w/ Incentive PCY (B-D)					12,996				62,361				8,998
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					14,096				67,637				9,759
I	True-Up Adjustment w/ Incentive (F*G)					14,096				67,637				9,759

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					2,789,111				1,570,088				132,060
	W incentive					2,789,111				1,570,088				132,060

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These Three Columns
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10			Project BG-1				Project BG-2				Project BH-1			
11	Schedule 12 (Yes or No)		Yes	B1906.1			Yes	B1906.1			Yes	B1908		
12	Life		40	At Yadkin 500 kV, install six 500 kV breakers			40	At Yadkin 500 kV, install six 500 kV breakers			40	Rebuild Lexington-Dooms 500 kV		
13	FCR W/O incentive Line 3		10.5695%				10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		4,398,307				5,644,742				74,606,362			
17	Annual Depreciation Exp		109,958				141,119				1,865,159			
18	In Service Month (1-12)		5				11				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	4,398,307	63,929	4,334,378		5,644,742	16,409	5,628,333		74,606,362	1,084,395	73,521,967	
39	W incentive	2015	4,398,307	63,929	4,334,378		5,644,742	16,409	5,628,333		74,606,362	1,084,395	73,521,967	
40	W / O incentive	2016	4,334,378	102,286	4,232,092		5,628,333	131,273	5,497,060		73,521,967	1,735,032	71,786,936	
41	W incentive	2016	4,334,378	102,286	4,232,092		5,628,333	131,273	5,497,060		73,521,967	1,735,032	71,786,936	
42	W / O incentive	2017	4,232,092	109,958	4,122,134		5,497,060	141,119	5,355,941		71,786,936	1,865,159	69,921,776	
43	W incentive	2017	4,232,092	109,958	4,122,134		5,497,060	141,119	5,355,941		71,786,936	1,865,159	69,921,776	
44	W / O incentive	2018	4,122,134	109,958	4,012,177		5,355,941	141,119	5,214,823		69,921,776	1,865,159	68,056,617	
45	W incentive	2018	4,122,134	109,958	4,012,177		5,355,941	141,119	5,214,823		69,921,776	1,865,159	68,056,617	
46	W / O incentive	2019	4,012,177	109,958	3,902,219	528,215	5,214,823	141,119	5,073,704	684,843	68,056,617	1,865,159	66,191,458	8,959,849
47	W incentive	2019	4,012,177	109,958	3,902,219	528,215	5,214,823	141,119	5,073,704	684,843	68,056,617	1,865,159	66,191,458	8,959,849
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A	Proj Rev Req w/o Incentive PCY*	618,549	801,944	10,132,506
B	Proj Rev Req w/ Incentive PCY*	618,549	801,944	10,132,506
C	Actual Rev Req w/o Incentive PCY*	619,263	802,758	10,504,256
D	Actual Rev Req w/ Incentive PCY*	619,263	802,758	10,504,256
E	TUA w/o Int w/o Incentive PCY (C-A)	714	814	371,750
F	TUA w/o Int w/ Incentive PCY (B-D)	714	814	371,750
G	Future Value Factor (1+i)^24 mo (ATT6)	1.08460	1.08460	1.08460
H	True-Up Adjustment w/o Incentive (E*G)	774	883	403,200
I	True-Up Adjustment w/ Incentive (F*G)	774	883	403,200

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	528,989	685,726	9,363,049
W incentive	528,989	685,726	9,363,049

These Three Columns
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References on All Pages

10			**Project BH-2**				**Project BH-3**				**Project BI**			
11	Schedule 12	(Yes or No)	Yes	B1908			Yes	B1908			Yes	B1698		
12	Life		40	Rebuild Lexington-Dooms 500 kV			40	Rebuild Lexington-Dooms 500 kV			40	Install a 2nd 500/230 kV transformer		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%				10.5695%	at Brambleton		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		30,160,827				20,570,454				21,908,705			
17	Annual Depreciation Exp		754,021				514,261				547,718			
18	In Service Month (1-12)		12				12				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
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28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	30,160,827	29,226	30,131,601									
39	W incentive	2015	30,160,827	29,226	30,131,601									
40	W / O incentive	2016	30,131,601	701,415	29,430,187		20,570,454	19,933	20,550,521		21,908,705	275,982	21,632,723	
41	W incentive	2016	30,131,601	701,415	29,430,187		20,570,454	19,933	20,550,521		21,908,705	275,982	21,632,723	
42	W / O incentive	2017	29,430,187	754,021	28,676,166		20,550,521	514,261	20,036,260		21,908,705	547,718	21,360,987	
43	W incentive	2017	29,430,187	754,021	28,676,166		20,550,521	514,261	20,036,260		21,908,705	547,718	21,360,987	
44	W / O incentive	2018	28,676,166	754,021	27,922,145		20,036,260	514,261	19,521,999		21,908,705	547,718	21,360,987	
45	W incentive	2018	28,676,166	754,021	27,922,145		20,036,260	514,261	19,521,999		21,908,705	547,718	21,360,987	
46	W / O incentive	2019	27,922,145	754,021	27,168,125	3,665,410	19,521,999	514,261	19,007,737	2,550,466	21,360,987	547,718	20,813,270	2,776,526
47	W incentive	2019	27,922,145	754,021	27,168,125	3,665,410	19,521,999	514,261	19,007,737	2,550,466	21,360,987	547,718	20,813,270	2,776,526
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A	Proj Rev Req w/o Incentive PCY*	4,272,910	1,893,596	3,235,643
B	Proj Rev Req w/ Incentive PCY*	4,272,910	1,893,596	3,235,643
C	Actual Rev Req w/o Incentive PCY*	4,296,403	2,988,584	3,185,601
D	Actual Rev Req w/ Incentive PCY*	4,296,403	2,988,584	3,185,601
E	TUA w/o Int w/o Incentive PCY (C-A)	23,493	1,094,988	(50,042)
F	TUA w/o Int w/ Incentive PCY (B-D)	23,493	1,094,988	(50,042)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.08460	1.08460	1.08460
H	True-Up Adjustment w/o Incentive (E*G)	25,480	1,187,622	(54,276)
I	True-Up Adjustment w/ Incentive (F*G)	25,480	1,187,622	(54,276)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	3,690,890	3,738,088	2,722,251
W incentive	3,690,890	3,738,088	2,722,251

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10			**Project BJ**				**Project BK**				**Project BL**			
11	Schedule 12	(Yes or No)	Yes	B1905.1			Yes	B1905.2			Yes	B1905.3		
12	Life		40	Surry to Skiffes Creek 500 kV Line			40	Surry 500 kV Station Work			40	Skiffes Creek 500-230 kV Tx and		
13	FCR W/O incentive	Line 3	10.5695%	(7 miles overhead)			10.5695%				10.5695%	Switching Station		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		195,000,000				1,834,471				114,055,318			
17	Annual Depreciation Exp		4,875,000				45,862				2,851,383			
18	In Service Month (1-12)		3				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014					1,834,471	26,664	1,807,807					
37	W incentive	2014					1,834,471	26,664	1,807,807					
38	W / O incentive	2015					1,807,807	42,662	1,765,145					
39	W incentive	2015					1,807,807	42,662	1,765,145					
40	W / O incentive	2016					1,765,145	42,662	1,722,483					
41	W incentive	2016					1,765,145	42,662	1,722,483					
42	W / O incentive	2017					1,722,483	45,862	1,676,621					
43	W incentive	2017					1,722,483	45,862	1,676,621					
44	W / O incentive	2018					1,676,621	45,862	1,630,759		114,055,318	118,808	113,936,510	
45	W incentive	2018					1,676,621	45,862	1,630,759		114,055,318	118,808	113,936,510	
46	W / O incentive	2019	195,000,000	3,859,375	191,140,625	20,014,608	1,630,759	45,862	1,584,898	215,802	113,936,510	2,851,383	111,085,127	14,743,239
47	W incentive	2019	195,000,000	3,859,375	191,140,625	20,014,608	1,630,759	45,862	1,584,898	215,802	113,936,510	2,851,383	111,085,127	14,743,239
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A	Proj Rev Req w/o Incentive PCY*					2,656,330				252,720				-
B	Proj Rev Req w/ Incentive PCY*					2,656,330				252,720				-
C	Actual Rev Req w/o Incentive PCY*					-				253,084				-
D	Actual Rev Req w/ Incentive PCY*					-				253,084				-
E	TUA w/o Int w/o Incentive PCY (C-A)					(2,656,330)				364				-
F	TUA w/o Int w/ Incentive PCY (B-D)					(2,656,330)				364				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					(2,881,052)				395				-
I	True-Up Adjustment w/ Incentive (F*G)					(2,881,052)				395				-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					17,133,556				216,196				14,743,239
	W incentive					17,133,556				216,196				14,743,239

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10			**Project BM-1**				**Project BM-2**				**Project BM-3**			
11	Schedule 12	(Yes or No)	Yes	B1905.4			Yes	B1905.4			Yes	B1905.4		
12	Life		40	Skiffes Creek - Whealton 230 kV line			40	Skiffes Creek - Whealton 230 kV line			40	Skiffes Creek - Whealton 230 kV line		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		7,585,377				14,074,806				39,654,276			
17	Annual Depreciation Exp		189,634				351,870				991,357			
18	In Service Month (1-12)		9				3				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
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32	W / O incentive	2012												
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34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015												
39	W incentive	2015												
40	W / O incentive	2016												
41	W incentive	2016												
42	W / O incentive	2017	7,585,377	55,310	7,530,067									
43	W incentive	2017	7,585,377	55,310	7,530,067									
44	W / O incentive	2018	7,585,377	189,634	7,395,743		14,074,806	278,564	13,796,242		39,654,276	41,307	39,612,969	
45	W incentive	2018	7,585,377	189,634	7,395,743		14,074,806	278,564	13,796,242		39,654,276	41,307	39,612,969	
46	W / O incentive	2019	7,585,377	189,634	7,395,743	981,351	13,796,242	351,870	13,444,372	1,791,472	39,612,969	991,357	38,621,613	5,125,868
47	W incentive	2019	7,585,377	189,634	7,395,743	981,351	13,796,242	351,870	13,444,372	1,791,472	39,612,969	991,357	38,621,613	5,125,868
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A	Proj Rev Req w/o Incentive PCY*					-				-				-
B	Proj Rev Req w/ Incentive PCY*					-				-				-
C	Actual Rev Req w/o Incentive PCY*					324,079				-				-
D	Actual Rev Req w/ Incentive PCY*					324,079				-				-
E	TUA w/o Int w/o Incentive PCY (C-A)					324,079				-				-
F	TUA w/o Int w/ Incentive PCY (B-D)					324,079				-				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					351,496				-				-
I	True-Up Adjustment w/ Incentive (F*G)					351,496				-				-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		1,332,847	1,791,472	5,125,868
W incentive		1,332,847	1,791,472	5,125,868

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These Three Columns are Repeated to Provide Line Number References on All Pages														
10			**Project BN**				**Project BO**				**Project BP**			
11	Schedule 12	(Yes or No)	Yes	B1905.5			Yes	B1905.6			Yes	B1905.7		
12	Life		40	Whealton 230 kV breakers			40	Yorktown 230 kV work			40	Lanexa 115 kV work		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		5,169,196				3,000,000				1,000,000			
17	Annual Depreciation Exp		129,230				75,000				25,000			
18	In Service Month (1-12)		6				10				7			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015												
39	W incentive	2015												
40	W / O incentive	2016	5,169,196	65,116	5,104,080									
41	W incentive	2016	5,169,196	65,116	5,104,080									
42	W / O incentive	2017	5,104,080	129,230	4,974,850									
43	W incentive	2017	5,104,080	129,230	4,974,850									
44	W / O incentive	2018	4,974,850	129,230	4,845,620		3,000,000	15,625	2,984,375					
45	W incentive	2018	4,974,850	129,230	4,845,620		3,000,000	15,625	2,984,375					
46	W / O incentive	2019	4,845,620	129,230	4,716,390	634,559	2,984,375	75,000	2,909,375	386,471	1,000,000	11,458	988,542	59,624
47	W incentive	2019	4,845,620	129,230	4,716,390	634,559	2,984,375	75,000	2,909,375	386,471	1,000,000	11,458	988,542	59,624
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A	Proj Rev Req w/o Incentive PCY*					653,849				-				-
B	Proj Rev Req w/ Incentive PCY*					653,849				-				-
C	Actual Rev Req w/o Incentive PCY*					751,619				-				-
D	Actual Rev Req w/ Incentive PCY*					751,619				-				-
E	TUA w/o Int w/o Incentive PCY (C-A)					97,770				-				-
F	TUA w/o Int w/ Incentive PCY (B-D)					97,770				-				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					106,041				-				-
I	True-Up Adjustment w/ Incentive (F*G)					106,041				-				-
	TUA = True-Up Adjusment PCY = Previous Calendar Year													
	W / O incentive					740,600				386,471				59,624
	W incentive					740,600				386,471				59,624

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These Three Columns
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References on All Pages

10			Project BR				Project BS				Project BT-1			
11	Schedule 12	(Yes or No)	Yes	B1905.9			Yes	B1907			Yes	B1909		
12	Life		40	Kings Mill, Peninmen, Toano, Waller,			40	Install a 3rd 500/230 kV TX at Clover			40	Uprate Bremo – Midlothian 230 kV to		
13	FCR W/O incentive	Line 3	10.5695%	Warkwick			10.5695%				10.5695%	its maximum operating temperature		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		7,659,621				19,043,057				764,184			
17	Annual Depreciation Exp		191,491				476,076				19,105			
18	In Service Month (1-12)		7				4				6			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015									764,184	9,626	754,558	
39	W incentive	2015									764,184	9,626	754,558	
40	W / O incentive	2016					19,043,057	313,694	18,729,363		754,558	17,772	736,786	
41	W incentive	2016					19,043,057	313,694	18,729,363		754,558	17,772	736,786	
42	W / O incentive	2017					18,729,363	476,076	18,253,287		736,786	19,105	717,681	
43	W incentive	2017					18,729,363	476,076	18,253,287		736,786	19,105	717,681	
44	W / O incentive	2018					18,253,287	476,076	17,777,210		717,681	19,105	698,577	
45	W incentive	2018					18,253,287	476,076	17,777,210		717,681	19,105	698,577	
46	W / O incentive	2019	7,659,621	87,766	7,571,855	456,701	17,777,210	476,076	17,301,134	2,329,883	698,577	19,105	679,472	91,931
47	W incentive	2019	7,659,621	87,766	7,571,855	456,701	17,777,210	476,076	17,301,134	2,329,883	698,577	19,105	679,472	91,931
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A	Proj Rev Req w/o Incentive PCY*					-				2,724,772				106,444
B	Proj Rev Req w/ Incentive PCY*					-				2,724,772				106,444
C	Actual Rev Req w/o Incentive PCY*					-				2,768,926				107,774
D	Actual Rev Req w/ Incentive PCY*					-				2,768,926				107,774
E	TUA w/o Int w/o Incentive PCY (C-A)					-				44,154				1,331
F	TUA w/o Int w/ Incentive PCY (B-D)					-				44,154				1,331
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					-				47,890				1,443
I	True-Up Adjustment w/ Incentive (F*G)					-				47,890				1,443

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					456,701				2,377,773				93,374
	W incentive					456,701				2,377,773				93,374

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

			Project BT-2				Project BT-3				Project BU			
10														
11	Schedule 12	(Yes or No)	Yes	B1909			Yes	B1909			Yes	B1328		
12	Life		40	Uprate Bremo – Midlothian 230 kV to			40	Uprate Bremo – Midlothian 230 kV to			40	Uprate the 3.63 mile line section between		
13	FCR W/O incentive	Line 3	10.5695%	its maximum operating temperature			10.5695%	its maximum operating temperature			10.5695%	Possum and Dumfries substations.		
14	Incentive Factor (Basis Points /100)		0				0				0	Replace 1600 amp wave trap at Possum Point		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		1,217,598				1,365,513				3,881,027			
17	Annual Depreciation Exp		30,440				34,138				97,026			
18	In Service Month (1-12)		6				5				12			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015									3,881,027	3,761	3,877,266	
39	W incentive	2015									3,881,027	3,761	3,877,266	
40	W / O incentive	2016	1,217,598	15,338	1,202,260						3,877,266	90,256	3,787,010	
41	W incentive	2016	1,217,598	15,338	1,202,260						3,877,266	90,256	3,787,010	
42	W / O incentive	2017	1,202,260	30,440	1,171,820		1,365,513	21,336	1,344,177		3,787,010	97,026	3,689,984	
43	W incentive	2017	1,202,260	30,440	1,171,820		1,365,513	21,336	1,344,177		3,787,010	97,026	3,689,984	
44	W / O incentive	2018	1,171,820	30,440	1,141,380		1,344,177	34,138	1,310,039		3,689,984	97,026	3,592,959	
45	W incentive	2018	1,171,820	30,440	1,141,380		1,344,177	34,138	1,310,039		3,689,984	97,026	3,592,959	
46	W / O incentive	2019	1,141,380	30,440	1,110,940	149,470	1,310,039	34,138	1,275,901	170,799	3,592,959	97,026	3,495,933	471,657
47	W incentive	2019	1,141,380	30,440	1,110,940	149,470	1,310,039	34,138	1,275,901	170,799	3,592,959	97,026	3,495,933	471,657
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A	Proj Rev Req w/o Incentive PCY*					399,304				-				526,494
B	Proj Rev Req w/ Incentive PCY*					399,304				-				526,494
C	Actual Rev Req w/o Incentive PCY*					177,043				124,582				552,851
D	Actual Rev Req w/ Incentive PCY*					177,043				124,582				552,851
E	TUA w/o Int w/o Incentive PCY (C-A)					(222,261)				124,582				26,357
F	TUA w/o Int w/ Incentive PCY (B-D)					(222,261)				124,582				26,357
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					(241,064)				135,121				28,587
I	True-Up Adjustment w/ Incentive (F*G)					(241,064)				135,121				28,587

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		(91,595)	305,920	500,243
W incentive		(91,595)	305,920	500,243

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are Repeated to Provide
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References on All Pages

10				**Project BV-1A**				**Project BV-1B**				**Project BV-1C**		
11	Schedule 12	(Yes or No)	Yes	B1912			Yes	B1912			Yes	B1912		
12	Life		40	Install a 500 MVAR SVC at			40	Install a 500 MVAR SVC at			40	Install a 500 MVAR SVC at		
13	FCR W/O incentive	Line 3	10.5695%	Landstown 230 kV			10.5695%	Landstown 230 kV			10.5695%	Landstown 230 kV		
14	Incentive Factor (Basis Points /100)		0	(Includes project modifications.)			0	(Includes project modifications.)			0	(Includes project modifications.)		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		20,513,095				25,133,568				24,955,831			
17	Annual Depreciation Exp		512,827				628,339				623,896			
18	In Service Month (1-12)		4				6				11			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
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32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015												
39	W incentive	2015												
40	W / O incentive	2016	20,513,095	337,910	20,175,185		25,133,568	316,605	24,816,963		24,955,831	72,546	24,883,285	
41	W incentive	2016	20,513,095	337,910	20,175,185		25,133,568	316,605	24,816,963		24,955,831	72,546	24,883,285	
42	W / O incentive	2017	20,175,185	512,827	19,662,358		24,816,963	628,339	24,188,624		24,883,285	623,896	24,259,389	
43	W incentive	2017	20,175,185	512,827	19,662,358		24,816,963	628,339	24,188,624		24,883,285	623,896	24,259,389	
44	W / O incentive	2018	19,662,358	512,827	19,149,531		24,188,624	628,339	23,560,285		24,259,389	623,896	23,635,493	
45	W incentive	2018	19,662,358	512,827	19,149,531		24,188,624	628,339	23,560,285		24,259,389	623,896	23,635,493	
46	W / O incentive	2019	19,149,531	512,827	18,636,703	2,509,740	23,560,285	628,339	22,931,945	3,085,342	23,635,493	623,896	23,011,598	3,089,083
47	W incentive	2019	19,149,531	512,827	18,636,703	2,509,740	23,560,285	628,339	22,931,945	3,085,342	23,635,493	623,896	23,011,598	3,089,083
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A	Proj Rev Req w/o Incentive PCY*					2,551,821				3,487,195				3,342,435
B	Proj Rev Req w/ Incentive PCY*					2,551,821				3,487,195				3,342,435
C	Actual Rev Req w/o Incentive PCY*					2,982,675				3,654,507				3,628,664
D	Actual Rev Req w/ Incentive PCY*					2,982,675				3,654,507				3,628,664
E	TUA w/o Int w/o Incentive PCY (C-A)					430,854				167,312				286,229
F	TUA w/o Int w/ Incentive PCY (B-D)					430,854				167,312				286,229
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					467,303				181,466				310,444
I	True-Up Adjustment w/ Incentive (F*G)					467,303				181,466				310,444

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	2,977,043	3,266,809	3,399,527
W incentive	2,977,043	3,266,809	3,399,527

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References on All Pages

10			Project BV-2				Project BW				Project BX			
11	Schedule 12	(Yes or No)	Yes	B1912			Yes	B1701			Yes	B1791		
12	Life		40	125 MVAr STATCOM at Lynnhaven			40	Reconductor line #2104			40	Wreck and rebuild 2.1 mile section of		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%	(Fredericksburg - Cranes Corner 230 kV)			10.5695%	Gordonsville and Somerset (Line #11)		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		27,285,426				3,178,496				3,441,461			
17	Annual Depreciation Exp		682,136				79,462				86,037			
18	In Service Month (1-12)		4				11				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
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32	W / O incentive	2012												
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34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015									3,441,461	50,021	3,391,440	
39	W incentive	2015									3,441,461	50,021	3,391,440	
40	W / O incentive	2016					3,178,496	9,240	3,169,256		3,391,440	80,034	3,311,406	
41	W incentive	2016					3,178,496	9,240	3,169,256		3,391,440	80,034	3,311,406	
42	W / O incentive	2017	27,285,426	483,179	26,802,247		3,169,256	79,462	3,089,794		3,311,406	86,037	3,225,369	
43	W incentive	2017	27,285,426	483,179	26,802,247		3,169,256	79,462	3,089,794		3,311,406	86,037	3,225,369	
44	W / O incentive	2018	26,802,247	682,136	26,120,111		3,089,794	79,462	3,010,331		3,225,369	86,037	3,139,333	
45	W incentive	2018	26,802,247	682,136	26,120,111		3,089,794	79,462	3,010,331		3,225,369	86,037	3,139,333	
46	W / O incentive	2019	26,120,111	682,136	25,437,975	3,406,857	3,010,331	79,462	2,930,869	393,441	3,139,333	86,037	3,053,296	413,302
47	W incentive	2019	26,120,111	682,136	25,437,975	3,406,857	3,010,331	79,462	2,930,869	393,441	3,139,333	86,037	3,053,296	413,302
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A	Proj Rev Req w/o Incentive PCY*					3,352,202				439,332				484,055
B	Proj Rev Req w/ Incentive PCY*					3,352,202				439,332				484,055
C	Actual Rev Req w/o Incentive PCY*					2,818,829				462,164				484,543
D	Actual Rev Req w/ Incentive PCY*					2,818,829				462,164				484,543
E	TUA w/o Int w/o Incentive PCY (C-A)					(533,373)				22,832				488
F	TUA w/o Int w/ Incentive PCY (B-D)					(533,373)				22,832				488
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					(578,495)				24,764				529
I	True-Up Adjustment w/ Incentive (F*G)					(578,495)				24,764				529

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive				2,828,362				418,204				413,831
W incentive				2,828,362				418,204				413,831

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References on All Pages

10			Project BY-1				Project BY-2				Project BY-3			
11	Schedule 12	(Yes or No)	Yes	B1694			Yes	B1694			Yes	B1694		
12	Life		40	Rebuild Loudoun - Brambleton 500 kV			40	Rebuild Loudoun - Brambleton 500 kV			40	Rebuild Loudoun - Brambleton 500 kV		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		27,894,903				2,712,333				15,703,275			
17	Annual Depreciation Exp		697,373				67,808				392,582			
18	In Service Month (1-12)		2				5				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
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36	W / O incentive	2014												
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38	W / O incentive	2015												
39	W incentive	2015												
40	W / O incentive	2016	27,894,903	567,629	27,327,274		2,712,333	39,423	2,672,910		15,703,275	197,813	15,505,462	
41	W incentive	2016	27,894,903	567,629	27,327,274		2,712,333	39,423	2,672,910		15,703,275	197,813	15,505,462	
42	W / O incentive	2017	27,327,274	697,373	26,629,902		2,672,910	67,808	2,605,101		15,505,462	392,582	15,112,881	
43	W incentive	2017	27,327,274	697,373	26,629,902		2,672,910	67,808	2,605,101		15,505,462	392,582	15,112,881	
44	W / O incentive	2018	26,629,902	697,373	25,932,529		2,605,101	67,808	2,537,293		15,112,881	392,582	14,720,299	
45	W incentive	2018	26,629,902	697,373	25,932,529		2,605,101	67,808	2,537,293		15,112,881	392,582	14,720,299	
46	W / O incentive	2019	25,932,529	697,373	25,235,156	3,401,463	2,537,293	67,808	2,469,485	332,405	14,720,299	392,582	14,327,717	1,927,700
47	W incentive	2019	25,932,529	697,373	25,235,156	3,401,463	2,537,293	67,808	2,469,485	332,405	14,720,299	392,582	14,327,717	1,927,700
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A	Proj Rev Req w/o Incentive PCY*					2,869,843				2,934,718				-
B	Proj Rev Req w/ Incentive PCY*					2,869,843				2,934,718				-
C	Actual Rev Req w/o Incentive PCY*					3,986,805				389,576				2,259,191
D	Actual Rev Req w/ Incentive PCY*					3,986,805				389,576				2,259,191
E	TUA w/o Int w/o Incentive PCY (C-A)					1,116,962				(2,545,142)				2,259,191
F	TUA w/o Int w/ Incentive PCY (B-D)					1,116,962				(2,545,142)				2,259,191
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					1,211,455				(2,760,457)				2,450,315
I	True-Up Adjustment w/ Incentive (F*G)					1,211,455				(2,760,457)				2,450,315

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					4,612,918				(2,428,052)				4,378,016
	W incentive					4,612,918				(2,428,052)				4,378,016

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References on All Pages

10			**Project BY-4**				**Project BZ-1**				**Project BZ-2**			
11	Schedule 12	(Yes or No)	Yes	B1694			Yes	B1696			Yes	B1696		
12	Life		40	Rebuild Loudoun - Brambleton 500 kV			40	Install a breaker and a half scheme with			40	Install a breaker and a half scheme with		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%	a minimum of eight 230 kV breakers			10.5695%	a minimum of eight 230 kV breakers		
14	Incentive Factor (Basis Points /100)		0				0	for five existing lines at Idylwood 230 kV			0	for five existing lines at Idylwood 230 kV		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		477,481				2,144,992				14,000,000			
17	Annual Depreciation Exp		11,937				53,625				350,000			
18	In Service Month (1-12)		7				1				1			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015												
39	W incentive	2015												
40	W / O incentive	2016	477,481	5,089	472,392		2,144,992	47,805	2,097,187					
41	W incentive	2016	477,481	5,089	472,392		2,144,992	47,805	2,097,187					
42	W / O incentive	2017	472,392	11,937	460,455		2,097,187	53,625	2,043,562					
43	W incentive	2017	472,392	11,937	460,455		2,097,187	53,625	2,043,562					
44	W / O incentive	2018	460,455	11,937	448,518		2,043,562	53,625	1,989,937					
45	W incentive	2018	460,455	11,937	448,518		2,043,562	53,625	1,989,937					
46	W / O incentive	2019	448,518	11,937	436,580	58,712	1,989,937	53,625	1,936,313	261,118	14,000,000	335,417	13,664,583	1,736,507
47	W incentive	2019	448,518	11,937	436,580	58,712	1,989,937	53,625	1,936,313	261,118	14,000,000	335,417	13,664,583	1,736,507
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A	Proj Rev Req w/o Incentive PCY*					-				895,531				-
B	Proj Rev Req w/ Incentive PCY*					-				895,531				-
C	Actual Rev Req w/o Incentive PCY*					68,807				306,060				-
D	Actual Rev Req w/ Incentive PCY*					68,807				306,060				-
E	TUA w/o Int w/o Incentive PCY (C-A)					68,807				(589,471)				-
F	TUA w/o Int w/ Incentive PCY (B-D)					68,807				(589,471)				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					74,628				(639,339)				-
I	True-Up Adjustment w/ Incentive (F*G)					74,628				(639,339)				-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive	133,340	(378,221)	1,736,507
	W incentive	133,340	(378,221)	1,736,507

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10			Project CA-1				Project CA-2				Project CA-3			
11	Schedule 12 (Yes or No)		Yes	B2373			Yes	B2373			Yes	B2373		
12	Life		40	Build 2nd Loudoun - Brambleton 500 kV			40	Build 2nd Loudoun - Brambleton 500 kV			40	Build 2nd Loudoun - Brambleton 500 kV		
13	FCR W/O incentive Line 3		10.5695%	within existing ROW. The Loudoun -			10.5695%	within existing ROW. The Loudoun -			10.5695%	within existing ROW. The Loudoun -		
14	Incentive Factor (Basis Points /100)		0	Brambleton 230 kV line relocated as an			0	Brambleton 230 kV line relocated as an			0	Brambleton 230 kV line relocated as an		
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%	underbuild on the new 500 kV line.			10.5695%	underbuild on the new 500 kV line.			10.5695%	underbuild on the new 500 kV line.		
16	Investment		28,003,295				14,800,890				1,620,339			
17	Annual Depreciation Exp		700,082				370,022				40,508			
18	In Service Month (1-12)		12				9				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	28,003,295	27,135	27,976,160									
39	W incentive	2015	28,003,295	27,135	27,976,160									
40	W / O incentive	2016	27,976,160	651,239	27,324,921		14,800,890	100,394	14,700,496		1,620,339	1,570	1,618,769	
41	W incentive	2016	27,976,160	651,239	27,324,921		14,800,890	100,394	14,700,496		1,620,339	1,570	1,618,769	
42	W / O incentive	2017	27,324,921	700,082	26,624,838		14,700,496	370,022	14,330,474		1,618,769	40,508	1,578,260	
43	W incentive	2017	27,324,921	700,082	26,624,838		14,700,496	370,022	14,330,474		1,618,769	40,508	1,578,260	
44	W / O incentive	2018	26,624,838	700,082	25,924,756		14,330,474	370,022	13,960,452		1,578,260	40,508	1,537,752	
45	W incentive	2018	26,624,838	700,082	25,924,756		14,330,474	370,022	13,960,452		1,578,260	40,508	1,537,752	
46	W / O incentive	2019	25,924,756	700,082	25,224,673	3,403,208	13,960,452	370,022	13,590,430	1,826,021	1,537,752	40,508	1,497,243	200,901
47	W incentive	2019	25,924,756	700,082	25,224,673	3,403,208	13,960,452	370,022	13,590,430	1,826,021	1,537,752	40,508	1,497,243	200,901
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A	Proj Rev Req w/o Incentive PCY*					3,969,949				2,237,852				-
B	Proj Rev Req w/ Incentive PCY*					3,969,949				2,237,852				-
C	Actual Rev Req w/o Incentive PCY*					3,989,063				2,139,860				235,411
D	Actual Rev Req w/ Incentive PCY*					3,989,063				2,139,860				235,411
E	TUA w/o Int w/o Incentive PCY (C-A)					19,114				(97,992)				235,411
F	TUA w/o Int w/ Incentive PCY (B-D)					19,114				(97,992)				235,411
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					20,731				(106,282)				255,327
I	True-Up Adjustment w/ Incentive (F*G)					20,731				(106,282)				255,327

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					3,423,939				1,719,738				456,228
	W incentive					3,423,939				1,719,738				456,228

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These Three Columns
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References on All Pages

10			Project CB-1				Project CB-2				Project CC			
11	Schedule 12	(Yes or No)	Yes	B2582			Yes	B2582			Yes	B1911		
12	Life		40	Rebuild the Elmont - Cunningham 500 kV line			40	Rebuild the Elmont - Cunningham 500 kV line			40	Add a second Valley 500/230 kV TX		
13	FCR W/O incentive	Line 3	10.5695%				10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		66,483,984				26,401,407				21,934,743			
17	Annual Depreciation Exp		1,662,100				660,035				548,369			
18	In Service Month (1-12)		5				1				6			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015												
39	W incentive	2015												
40	W / O incentive	2016									21,934,743	276,310	21,658,433	
41	W incentive	2016									21,934,743	276,310	21,658,433	
42	W / O incentive	2017	66,483,984	1,038,812	65,445,172						21,658,433	548,369	21,110,065	
43	W incentive	2017	66,483,984	1,038,812	65,445,172						21,658,433	548,369	21,110,065	
44	W / O incentive	2018	65,445,172	1,662,100	63,783,072		26,401,407	632,534	25,768,873		21,110,065	548,369	20,561,696	
45	W incentive	2018	65,445,172	1,662,100	63,783,072		26,401,407	632,534	25,768,873		21,110,065	548,369	20,561,696	
46	W / O incentive	2019	63,783,072	1,662,100	62,120,973	8,315,828	25,768,873	660,035	25,108,838	3,348,801	20,561,696	548,369	20,013,328	2,692,662
47	W incentive	2019	63,783,072	1,662,100	62,120,973	8,315,828	25,768,873	660,035	25,108,838	3,348,801	20,561,696	548,369	20,013,328	2,692,662
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A	Proj Rev Req w/o Incentive PCY*					3,347,610				274,997				3,292,896
B	Proj Rev Req w/ Incentive PCY*					3,347,610				274,997				3,292,896
C	Actual Rev Req w/o Incentive PCY*					6,065,624				-				3,155,697
D	Actual Rev Req w/ Incentive PCY*					6,065,624				-				3,155,697
E	TUA w/o Int w/o Incentive PCY (C-A)					2,718,013				(274,997)				(137,199)
F	TUA w/o Int w/ Incentive PCY (B-D)					2,718,013				(274,997)				(137,199)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					2,947,953				(298,261)				(148,806)
I	True-Up Adjustment w/ Incentive (F*G)					2,947,953				(298,261)				(148,806)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					11,263,781				3,050,539				2,543,856
	W incentive					11,263,781				3,050,539				2,543,856

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References on All Pages

10			**Project CE**				**Project CJ-1**				**Project CJ-2**			
11	Schedule 12	(Yes or No)	Yes	B2471			Yes	B2744			Yes	B2744		
12	Life		40	R/P Midlothian 500 kV breaker and			40	Rebuild the Carson-Rogers rd 500 kV circuit			40	Rebuild the Carson-Rogers rd 500 kV circuit		
13	FCR W/O incentive	Line 3	10.5695%	M.O. switches with 3 breaker 500 kV ring bus.			10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0	Terminate Lines #563 Carson - Midlothian,			0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%	#576 Midlothian - North Anna,			10.5695%				10.5695%			
16	Investment		7,896,194	Transformer #2 in new ring			27,730,674				34,351,518			
17	Annual Depreciation Exp		197,405				693,267				858,788			
18	In Service Month (1-12)		11				1				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
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26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	7,896,194	22,954	7,873,240									
39	W incentive	2015	7,896,194	22,954	7,873,240									
40	W / O incentive	2016	7,873,240	183,632	7,689,608									
41	W incentive	2016	7,873,240	183,632	7,689,608									
42	W / O incentive	2017	7,689,608	197,405	7,492,203									
43	W incentive	2017	7,689,608	197,405	7,492,203									
44	W / O incentive	2018	7,492,203	197,405	7,294,798		27,730,674	664,381	27,066,293		34,351,518	536,742	33,814,776	
45	W incentive	2018	7,492,203	197,405	7,294,798		27,730,674	664,381	27,066,293		34,351,518	536,742	33,814,776	
46	W / O incentive	2019	7,294,798	197,405	7,097,393	957,998	27,066,293	693,267	26,373,026	3,517,407	33,814,776	858,788	32,955,988	4,387,463
47	W incentive	2019	7,294,798	197,405	7,097,393	957,998	27,066,293	693,267	26,373,026	3,517,407	33,814,776	858,788	32,955,988	4,387,463
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A	Proj Rev Req w/o Incentive PCY*					1,111,629				-				-
B	Proj Rev Req w/ Incentive PCY*					1,111,629				-				-
C	Actual Rev Req w/o Incentive PCY*					1,122,945				-				-
D	Actual Rev Req w/ Incentive PCY*					1,122,945				-				-
E	TUA w/o Int w/o Incentive PCY (C-A)					11,316				-				-
F	TUA w/o Int w/ Incentive PCY (B-D)					11,316				-				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					12,274				-				-
I	True-Up Adjustment w/ Incentive (F*G)					12,274				-				-
	TUA = True-Up Adjusment													
	PCY = Previous Calendar Year													
	W / O incentive					970,271				3,517,407				4,387,463
	W incentive					970,271				3,517,407				4,387,463

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These Three Columns
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			Project CD-1				Project CF-1				Project CF-2			
10														
11	Schedule 12 (Yes or No)		Yes	B2443			Yes	B2665			Yes	B2665		
12	Life		40	Glebe to Station C 230 kV UG line			40	Rebuild the Cunningham - Dooms 500 kV line			40	Rebuild the Cunningham - Dooms 500 kV line		
13	FCR W/O incentive Line 3		10.5695%				10.5695%				10.5695%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%				10.5695%				10.5695%			
16	Investment		20,000,000				40,000,000				22,875,170			
17	Annual Depreciation Exp		500,000				1,000,000				571,879			
18	In Service Month (1-12)		12				5				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
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27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
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32	W / O incentive	2012												
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34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015												
39	W incentive	2015												
40	W / O incentive	2016												
41	W incentive	2016												
42	W / O incentive	2017												
43	W incentive	2017												
44	W / O incentive	2018					40,000,000	625,000	39,375,000					
45	W incentive	2018					40,000,000	625,000	39,375,000					
46	W / O incentive	2019	20,000,000	20,833	19,979,167	108,867	39,375,000	1,000,000	38,375,000	5,108,902	22,875,170	357,425	22,517,745	1,856,741
47	W incentive	2019	20,000,000	20,833	19,979,167	108,867	39,375,000	1,000,000	38,375,000	5,108,902	22,875,170	357,425	22,517,745	1,856,741
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59														
A	Proj Rev Req w/o Incentive PCY*					-				-				-
B	Proj Rev Req w/ Incentive PCY*					-				-				-
C	Actual Rev Req w/o Incentive PCY*					-				-				-
D	Actual Rev Req w/ Incentive PCY*					-				-				-
E	TUA w/o Int w/o Incentive PCY (C-A)					-				-				-
F	TUA w/o Int w/ Incentive PCY (B-D)					-				-				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.08460				1.08460				1.08460
H	True-Up Adjustment w/o Incentive (E*G)					-				-				-
I	True-Up Adjustment w/ Incentive (F*G)					-				-				-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	108,867	5,108,902	1,856,741
W incentive	108,867	5,108,902	1,856,741

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10				**Project CG-1**					
11	Schedule 12	(Yes or No)	Yes	B2758			If Yes for Schedule 12 Include in this Total.	If No for Schedule 12 include in this Sum.	
12	Life		40	Rebuild Line #549 Dooms - Valley 500 kV line					
13	FCR W/O incentive	Line 3	10.5695%						
14	Incentive Factor (Basis Points /100)		0						
15	FCR W incentive L.13 +(L.14*L.5)		10.5695%						
16	Investment		25,000,000					Annual Revenue Requirement including Incentive if Applicable	Annual Revenue Requirement excluding Incentive
17	Annual Depreciation Exp		625,000						
18	In Service Month (1-12)		11						
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Total**	**Sum**	**Sum**
20	W / O incentive	2006							
21	W incentive	2006							
22	W / O incentive	2007							
23	W incentive	2007							
24	W / O incentive	2008							
25	W incentive	2008							
26	W / O incentive	2009							
27	W incentive	2009							
28	W / O incentive	2010							
29	W incentive	2010							
30	W / O incentive	2011							
31	W incentive	2011							
32	W / O incentive	2012							
33	W incentive	2012							
34	W / O incentive	2013							
35	W incentive	2013							
36	W / O incentive	2014							
37	W incentive	2014							
38	W / O incentive	2015							
39	W incentive	2015							
40	W / O incentive	2016							
41	W incentive	2016							
42	W / O incentive	2017							
43	W incentive	2017							
44	W / O incentive	2018							
45	W incentive	2018							
46	W / O incentive	2019	25,000,000	78,125	24,921,875	407,906	273,069,218		38,310,613
47	W incentive	2019	25,000,000	78,125	24,921,875	407,906	276,448,894	40,413,876	
48									
49									
50									
51									
52									
53									
54									
55									
56									
57									
58									
59									

A	Proj Rev Req w/o Incentive PCY*	-
B	Proj Rev Req w/ Incentive PCY*	-
C	Actual Rev Req w/o Incentive PCY*	-
D	Actual Rev Req w/ Incentive PCY*	-
E	TUA w/o Int w/o Incentive PCY (C-A)	-
F	TUA w/o Int w/ Incentive PCY (B-D)	-
G	Future Value Factor (1+i)^24 mo (ATT6)	1.08460
H	True-Up Adjustment w/o Incentive (E*G)	-
I	True-Up Adjustment w/ Incentive (F*G)	-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	407,906
W incentive	407,906

Virginia Electric and Power Company

ATTACHMENT H-16A

Attachment 8 - Securitization Workpaper

(000's)

Line #		
	Long Term Interest	
105	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
115	**Less LTD on Securitization Bonds**	0

Attachment 10

Virginia Electric and Power Company

ATTACHMENT H-16A

Attachment 9 - Depreciation Rates[1]

Depreciation Rates Applicable Through March 31, 2013

Plant Type	Applied Depreciation Rate
Transmission Plant	
Land	
Land Rights	1.36%
Structures and Improvements	1.41%
Station and Equipment	2.02%
Towers and Fixtures	2.36%
Poles and Fixtures	1.89%
Overhead conductors and Devices	1.90%
Underground Conduit	1.74%
Underground Conductors and Devices	2.50%
Roads and Trails	1.17%
General Plant	
Land Rights	1.70%
Structures and Improvements - Major	1.82%
Structures and Improvements - Other	2.26%
Communication Equipment	3.20%
Communication Equipment - Clearing	6.22%
Communication Equipment - Massed	6.22%
Communication Equipment - 25 Years	3.72%
Office Furniture and Equipment - EDP Hardware	27.38%
Office Furniture and Equipment - EDP Fixed Location	12.21%
Office Furniture and Equipment	1.64%
Laboratory Equipment	4.23%
Miscellaneous Equipment	2.53%
Stores Equipment	5.08%
Power Operated Equipment	8.16%
Tools, Shop and Garage Equipment	4.76%
Electric Vehicle Recharge Equipment	13.23%

[1] Depreciation rates may be changed only pursuant to a Section 205 or Section 206 proceeding.

Virginia Electric and Power Company

ATTACHMENT H-16A

Attachment 9 - Depreciation Rates (Continued)[1]

Depreciation Rates Applicable On April 1, 2013 And Through December 31, 2016

Plant Type	Applied Depreciation Rate
Transmission Plant	
Land	
Land Rights	1.17%
Structures and Improvements	1.53%
Station Equipment	2.89%
Station Equipment - Power Supply Computer Equipment	10.46%
Towers and Fixtures	2.08%
Poles and Fixtures	2.11%
Overhead conductors and Devices	1.92%
Underground Conduit	1.65%
Underground Conductors and Devices	1.92%
Roads and Trails	1.06%
General Plant	
Land	
Land Rights	1.71%
Structures and Improvements - Major	1.95%
Structures and Improvements - Other	2.82%
Office Furniture and Equipment	2.68%
Office Furniture and Equipment - EDP Hardware	15.26%
Office Furniture and Equipment - EDP Fixed Location	7.26%
Transportation Equipment	3.90%
Stores Equipment	2.52%
Tools, Shop and Garage Equipment	4.32%
Laboratory Equipment	3.69%
Power Operated Equipment	4.75%
Communication Equipment	3.14%
Communication Equipment - Massed	5.97%
Communication Equipment - 25 Years	2.48%
Miscellaneous Equipment	6.67%

[1] Depreciation rates may be changed only pursuant to a Section 205 or Section 206 proceeding.

Virginia Electric and Power Company

ATTACHMENT H-16A

Attachment 9 - Depreciation Rates (Continued)[1]

Depreciation Rates Applicable On And After January 1, 2017

Plant Type	Applied Depreciation Rate
Transmission Plant	
Land	
Land Rights	1.31%
Structures and Improvements	1.59%
Station Equipment	3.05%
Station Equipment - Power Supply Computer Equipment	7.21%
Towers and Fixtures	2.30%
Poles and Fixtures	2.33%
Overhead conductors and Devices	2.18%
Underground Conduit	2.10%
Underground Conductors and Devices	2.03%
Roads and Trails	1.06%
General Plant	
Land	
Land Rights	1.49%
Structures and Improvements-Major	2.38%
Structures and Improvements-Other	2.24%
Office Furniture and Equipment - 2012 and Prior	8.97%
Office Furniture and Equipment - 2013 and Subsequent	6.67%
Office Furniture and Equipment-EDP Hardware - 2012 and Prior	65.49%
Office Furniture and Equipment-EDP Hardware - 2013 and Subsequent	20.00%
Office Furniture and Equipment-EDP Fixed Location - 2012 and Prior	10.83%
Office Furniture and Equipment-EDP Fixed Location - 2013 and Subsequent	20.00%
Transportation Equipment	5.75%
Stores Equipment - 2012 and Prior	4.25%
Stores Equipment - 2013 and Subsequent	4.00%
Tools, Shop, and Garage Equipment - 2012 and Prior	3.70%
Tools, Shop, and Garage Equipment - 2013 and Subsequent	4.00%
Tools, Shop, and Garage Equipment-Electric Vehicles	0.00%
Laboratory Equipment - 2012 and Prior	4.12%
Laboratory Equipment - 2013 and Subsequent	4.00%
Power Operated Equipment	6.49%
Communication Equipment - 2012 and Prior	3.70%
Communication Equipment - 2013 and Subsequent	4.00%
Communication Equupment-Clearing	0.00%
Communication Equipment-Massed - 2012 and Prior	8.61%
Communication Equipment-Massed - 2013 and Subsequent	6.67%
Communication Equpment-25 Years - 2012 and Prior	2.66%
Communication Equpment-25 Years - 2013 and Subsequent	4.00%
Miscellaneous Equipment - 2012 and Prior	7.15%
Miscellaneous Equipment - 2013 and Subsequent	6.67%

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[1] Depreciation rates may be changed only pursuant to a Section 205 or Section 206 proceeding.

Attachment 10

Incremental Undergrounding Costs of the Garrisonville, Pleasant View, and NIVO Underground Projects

Section 1 -- Purpose

This Attachment 10 determines the appropriate amount of undergrounding costs to be allocated to each Network Customer for their Virginia loads in the Dominion Zone in accordance with the March 20, 2014 order of the Federal Energy Regulatory Commission in Docket No. EL10-49-005 and in compliance with the Federal Energy Regulatory Commission's October 19, 2017 Order on Initial Decision issued in Opinion No. 555. To provide compensation for these costs, each Network Customer with Virginia loads in the Dominion Zone shall pay a monthly Demand Charge, which shall be known as the "UG Transmission Charge" as determined herein.

Section 2 -- Underground ("UG") Transmission Project Descriptions

The projects are generally described below. The projects may be modified resulting in changes to their costs.

Garrisonville	The Aquia Harbor Terminal Station, the Garrisonville Substation excluding the distribution assets and the 230 kV shunt reactor banks in Garrisonville Substation, two underground transmission lines with associated duct systems running from Aquia Harbor Terminal Station to Garrisonville Substation, and modifications to transmission line protection equipment at Fredericksburg and Possum Point substations to interface with equipment at Aquia Harbor Terminal Station.
Pleasant View	An overhead transmission line running from Pleasant View Substation to Dry Mill South Station, facilities in Pleasant View Substation to facilitate connection of such transmission line, Dry Mill South Station, an underground transmission line with associated duct systems running from Dry Mill South Station to Breezy Knoll Station, Breezy Knoll Station, an overhead transmission line running from Breezy Knoll Station to Hamilton Substation, and Hamilton Substation excluding the distribution assets and the 230 kV shunt reactor bank in Hamilton Substation.
NIVO	Two underground transmission lines with associated duct system running from Beaumeade Substation to NIVO Substation, the NIVO Substation excluding distribution assets in NIVO Substation, and the facilities in Beaumeade Substation to facilitate connection of the two new underground transmission lines.

Attachment 10 (Continued)

Section 3 -- Determination of the Total Incremental Undergrounding Costs Revenue Requirement

The Total Incremental Undergrounding Costs Revenue Requirement shall be determined as set forth in the formula

Instructions:

1. Calculate this formula using data for Year on line 1.
2. On line 1, enter the year.
3. Lines 2a, 2b and 2c are the applicable UG Project Revenue Requirements consistent with the note below from either Attachment 10A if the applicable year is prior to 2015 or from Attachment 10B if the applicable year is after 2014.

Line	Description	Year
1	Enter the Rate Year	2019

(In Dollars)

	(1) Project Name	(2) Requirement	(3) Adjustment Factors	(4) Undergrounding
2a	Garrisonville	$31,080,757	92.49%	$28,745,226
2b	Pleasant View	$21,928,433	23.37%	$5,123,780
2c	NIVO	$2,495,284	22.09%	$551,248
3	**Total Incremental Undergrounding Costs Revenue Requirement**			**$34,420,254**

NOTE: All column 2 amounts are for the year indicated on line 1 and include true-up adjustments for the calendar year that is two years prior to that year. However in the event that a one-time net refund settlement addresses the charges and credits for a calendar year, the true-up adjustment for that calendar year shall equal zero. The revenue requirements in column (2) and column (4) include depreciation, return on capital investment, income taxes, and accumulated deferred income taxes (ADIT) , and property taxes in accordance with Opinion No. 555 Order on Initial Decision in FERC Docket No. EL10-49-005 . The Adjustment Factors set forth in column (3) are the ratio of the Estimated Incremental Underground Capital Costs divided by the Total Capital Costs shown on page 8 of Opinion No. 555 Order on Initial Decision in FERC Docket No. EL10-49-005 and shall not be changed except pursuant to a filing under the appropriate of Section 205 or 206.

Attachment 10 (Continued)

Section 4 --Annual UG Transmission Rate

The Annual UG Transmission Rate shall be calculated as follows:

Instructions:

1. On line 6, enter the portion of the amount on line 5 attributable to load located in Virginia as determined by PJM state estimator load bus data at the time of annual peak of the Dominion Zone.

Line	Description	Amounts
4	Total Incremental Undergrounding Costs Revenue Requirement (from Line 3) (dollars per year)	$34,420,254
5	Dominion Zone NSPL 1 CP Peak from Appendix A, line 169 (in Megawatts)	21,232.0
6	Virginia Portion of the Dominion Zone NSPL (Analysis of PJM load bus data) (in Megawatts)	19,908.4
7	Annual UG Transmission Rate (dollars per MW-year) (line 4 ÷ line 6)	$1,728.93

Attachment 10 (Continued)

Section 5 -- Billing

The UG Transmission Charge shall be billed in accordance with the PJM billing procedure applied to billing the monthly Demand Charge for Zone Network Loads in Section 34.1 of the PJM Tariff, but for purposes of this calculation, the Zone Network Loads (including losses) at the time of the annual peak of the Zone in which the load is located shall include only Virginia loads in the Dominion Zone. If necessary, PJM state estimator load bus MWs at the time of the annual peak of the Dominion Zone shall be used to separate Virginia loads from other loads in the Dominion Zone. VEPCO shall provide to PJM the contribution of each Network Customer's Virginia Portion of the Dominion Zone NSPL. Also, for the purpose of calculating the UG Transmission Charge in accordance with this attachment, the Annual UG Transmission Rate calculated on line 7 above shall be used instead of the rate for Network Integration Transmission Service ("RTZ").

Section 6 -- Revenue Crediting

A. For calculating the Annual Transmission Revenue Requirement and rate for Network Integration Transmission Service used for billing, the Total UG Project Adjusted Revenue Requirement amount, shown on line 4 of Section 4, shall be included in line 9 of Attachment 3, provided that the Annual Transmission Revenue Requirement is not one of the Annual Transmission Revenue Requirements used to determine refunds to each Network Customer as part of a net refund or charge settlement process that is in addition to the normal formula rate cycle billing process.

B. For calculating the annual true-up, the UG Transmission Charge revenues received by the Company shall be included in line 9 of Attachment 3, provided that the UG Transmission Charge revenues for the applicable year are not distributed to each Network Customer as part of a net refund or charge settlement process that is in addition to the normal formula rate cycle billing process.

Attachment 10

Virginia Electric and Power Company

Attachment 10A - UG Project Revenue Requirement for 2010 - 2014 Calendar Years

Year =

Inst. 1	For each month enter the amount included in Electric Plant in Service attributable to the UG Project for the applicable month.
Inst. 2	For each month enter the amount included in the Accumulated Provision for Depreciation of Electric Plant in Service attributable to the UG Project for the applicable month, and for each year enter the applicable depreciation expense.
Inst. 3	For each year enter the amount of Accumulated Deferred Income Tax ("ADIT") attributable to the UG Project for December 31 of each year.
Inst. 4	For each year enter the amount of Property Tax attributable to the UG Project.

Pleasant View UG Project Revenue Requirement

				Previous Year	Current Year												
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1	Inst. 1														-
2	Accumulated Depreciation	Note 1	Inst. 2														-
3	Accumulated Deferred Income Taxes	Note 2	Inst. 3														-
4	Applicable Rate Base		Line (1 + 2 + 3)														-
5	Return	Note 3	Line 4 * (Appendix A Line 129 + Incentive)														-
6	Income Taxes associated with Equity Return	Note 3	Line 5 * Appendix A Line 137 * (1-(126 / (129 + Incentive)))														-
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														-
8	Total Income Tax Provision		Line (6 + 7)														-
9	Depreciation-Transmission		Inst. 2														
10	Property Tax		Inst. 4														
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														-
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 4															
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 4															
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														0
15	Future Value Factor (1+i)^24 months		Attachment 6														1.08460
16	True-Up Adjustment		Line (14 * 15)														-
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														-

Note 1 The value in the amount column is calculated using 13 month average balance.

Note 2 The value in the amount column is calculated using average of beginning and end of year balances.

Note 3 Per FERC order in Docket No. ER08-1207-002, the ROE for each specific project
identified in that order will also include either an 150 or 125 basis point transmission
incentive adder as authorized by the Commission. The Incentive for Pleasant View = 125
basis points Authorized Incentive Adder times the Common Equity % from Appendix A
Line 122 = 0.0065

Note 4 These amounts do not include any True-Up Adjustments.

Garrisonville UG Project Revenue Requirement

				Previous Year	Current Year												
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1	Inst. 1														-
2	Accumulated Depreciation	Note 1	Inst. 2														-
3	Accumulated Deferred Income Taxes	Note 2	Inst. 3														-
4	Applicable Rate Base		Line (1 + 2 + 3)														-
5	Return	Note 3	Line 4 * (Appendix A Line 129 + Incentive)														-
6	Income Taxes associated with Equity Return	Note 3	Line 5 * Appendix A Line 137 * (1-(126 / (129 + Incentive)))														-
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														-
8	Total Income Tax Provision		Line (6 + 7)														-
9	Depreciation-Transmission		Inst. 2														
10	Property Tax		Inst. 4														
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														-
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 4															
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 4															
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														0
15	Future Value Factor (1+i)^24 months		Attachment 6														1.08460
16	True-Up Adjustment		Line (14 * 15)														-
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														-

Note 1 The value in the amount column is calculated using 13 month average balance.

Note 2 The value in the amount column is calculated using average of beginning and end of year balances.

Note 3 Per FERC order in Docket No. ER08-1207-002, the ROE for each specific project
identified in that order will also include either an 150 or 125 basis point transmission
incentive adder as authorized by the Commission. The Incentive for Garrisonville = 125
basis points Authorized Incentive Adder times the Common Equity % from Appendix A
Line 122 = 0.0065

Note 4 These amounts do not include any True-Up Adjustments.

Attachment 10

Virginia Electric and Power Company

Attachment 10A - UG Project Revenue Requirement for 2010 - 2014 Calendar Years

Year =

NIVO UG Project Revenue Requirement

				Previous Year	Current Year												
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1	Inst. 1														-
2	Accumulated Depreciation	Note 1	Inst. 2														-
3	Accumulated Deferred Income Taxes	Note 2	Inst. 3														-
4	Applicable Rate Base		Line (1 + 2 + 3)														-
5	Return		Line 4 * (Appendix A Line 129)														-
6	Income Taxes associated with Equity Return		Line 5 * Appendix A Line 137 * (1-(126 / 129))														-
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														-
8	Total Income Tax Provision		Line (6 + 7)														-
9	Depreciation-Transmission		Inst. 2														
10	Property Tax		Inst. 4														
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														-
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 3															
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 3															
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														0
15	Future Value Factor (1+i)^24 months		Attachment 6														1.08460
16	True-Up Adjustment		Line (14 * 15)														-
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														-

Note 1 The value in the amount column is calculated using 13 month average balance.

Note 2 The value in the amount column is calculated using average of beginning and end of year balances.

Note 3 These amounts do not include any True-Up Adjustments.

Attachment 10

Virginia Electric and Power Company

Attachment 10B - UG Project Revenue Requirement for Calendar Years after 2014

Year = 2019

Inst. 1 For each month enter the amount included in the Accumulated Provision for Depreciation of Electric Plant in Service attributable to the UG Project for the applicable month, and for each year enter the applicable depreciation expense.
Inst. 2 For each year enter the amount of Accumulated Deferred Income Tax ("ADIT") attributable to the UG Project for December 31 of each year.
Inst. 3 For each year enter the amount of Property Tax attributable to the UG Project.

Pleasant View UG Project Revenue Requirement

				Previous Year	Current Year													
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1		86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713
2	Accumulated Depreciation	4	Inst. 1	(14,427,750)	(12,708,549)	(12,864,840)	(13,021,131)	(13,177,422)	(13,333,713)	(13,490,004)	(13,646,295)	(13,802,586)	(13,958,877)	(14,115,168)	(14,271,459)	(14,427,750)	(13,634,273)
3	Accumulated Deferred Income Taxes	Note 2	Inst. 2	(3,874,221)												(3,892,982)	(3,883,602)
4	Applicable Rate Base		Line (1 + 2 + 3)														68,513,839
5	Return	Note 3	Line 4 * (Appendix A Line 129 + Incentive)														6,041,106
6	Income Taxes associated with Equity Return	Note 3	Line 5 * Appendix A Line 137 * (1-(126 / (129 + Incentive)))														1,556,625
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														(48,658)
8	Total Income Tax Provision		Line (6 + 7)														1,507,968
9	Depreciation-Transmission		Inst. 1														1,875,491
10	Property Tax		Inst. 3														176,929
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														9,601,494
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 4															-
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 4															11,365,441
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														11365440.78
15	Future Value Factor (1+i)^24 months		Attachment 6														1.08460
16	True-Up Adjustment		Line (14 * 15)														12,326,939.33
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														21,928,433

Note 1 The value in the amount column is calculated using 13 month average balance.
Note 2 The value in the amount column is calculated using average of beginning and end of year balances.
Note 3 Per FERC order in Docket No. ER08-1207-002, the ROE for each specific project identified in that order will also include either an 150 or 125 basis point transmission incentive adder as authorized by the Commission. The Incentive for Pleasant View = 125 basis points Authorized Incentive Adder times the Common Equity % from Appendix A Line 122 = 0.0065
Note 4 These amounts do not include any True-Up Adjustments.

Garrisonville UG Project Revenue Requirement

				Previous Year	Current Year													
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1		136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173
2	Accumulated Depreciation	Note 1	Inst. 1	(30,971,291)	(31,319,292)	(31,667,292)	(32,015,293)	(32,363,293)	(32,711,293)	(33,059,294)	(33,407,294)	(33,755,294)	(34,103,295)	(34,451,295)	(34,799,295)	(35,147,296)	(33,059,294)
3	Accumulated Deferred Income Taxes	Note 2	Inst. 2	(27,840,948)												(27,985,963)	(27,913,455)
4	Applicable Rate Base		Line (1 + 2 + 3)														75,945,424
5	Return	Note 3	Line 4 * (Appendix A Line 129 + Incentive)														6,696,375
6	Income Taxes associated with Equity Return	Note 3	Line 5 * Appendix A Line 137 * (1-(126 / (129 + Incentive)))														1,725,470
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														(53,935)
8	Total Income Tax Provision		Line (6 + 7)														1,671,535
9	Depreciation-Transmission		Inst. 1														4,176,004
10	Property Tax		Inst. 3														963,329
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														13,507,243
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 4															-
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 4															16,202,784
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														16202784.36
15	Future Value Factor (1+i)^24 months		Attachment 6														1.08460
16	True-Up Adjustment		Line (14 * 15)														17,573,514.64
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														31,080,757

Note 1 The value in the amount column is calculated using 13 month average balance.
Note 2 The value in the amount column is calculated using average of beginning and end of year balances.
Note 3 Per FERC order in Docket No. ER08-1207-002, the ROE for each specific project identified in that order will also include either an 150 or 125 basis point transmission incentive adder as authorized by the Commission. The Incentive for Garrisonville = 125 basis points Authorized Incentive Adder times the Common Equity % from Appendix A Line 122 = 0.0065
Note 4 These amounts do not include any True-Up Adjustments.

Attachment 10

Virginia Electric and Power Company

Attachment 10B - UG Project Revenue Requirement for Calendar Years after 2014

Year = 2019

NIVO UG Project Revenue Requirement

				Previous Year	Current Year												
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1		10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838
2	Accumulated Depreciation	Note 1	Inst. 1	(2,063,510)	(2,089,216)	(2,114,922)	(2,140,628)	(2,166,334)	(2,192,040)	(2,217,746)	(2,243,452)	(2,269,158)	(2,294,864)	(2,320,570)	(2,346,276)	(2,371,982)	(2,217,746)
3	Accumulated Deferred Income Taxes	Note 2	Inst. 2	(420,211)												(423,442)	(421,826)
4	Applicable Rate Base		Line (1 + 2 + 3)														7,474,266
5	Return		Line 4 * (Appendix A Line 129)														610,322
6	Income Taxes associated with Equity Return		Line 5 * Appendix A Line 137 * (1-(126 / 129))														153,034
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														(4,784)
8	Total Income Tax Provision		Line (6 + 7)														148,251
9	Depreciation-Transmission		Inst. 1														308,472
10	Property Tax		Inst. 3														20,559
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														1,087,603
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 3															-
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 3															1,297,882
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														1,297,882
15	Future Value Factor (1+i)^24 months		Attachment 6														1.08460
16	True-Up Adjustment		Line (14 * 15)														1,407,680.68
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														2,495,284

Note 1	The value in the amount column is calculated using 13 month average balance.
Note 2	The value in the amount column is calculated using average of beginning and end of year balances.
Note 3	These amounts do not include any True-Up Adjustments.

Attachment 11
AEP Formula Rate for January 1, 2019 to December 31, 2019

Projected Formula Rate for

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.

To be Effective January 1, 2019
Docket No ER17-405

Pursuant to Attachment H-20A (Formula Rate Implementation Protocols) in PJM Tariff, AEP has calculated its Projected Transmission Revenue Requirements (PTRR) to produce the Rates beginning January 1, 2019 through December 31, 2019. All the files pertaining to the PTRR are also posted on the PJM website in PDF format along with supporting workpapers. The first file provides the PTRR and rates for Network transmission service and Scheduling System Control and Dispatch Service, Schedule 1A.

AEP network service rate will increase effective January 1, 2019 from $24,822.32 per MW per year to $31,145.92 per MW per year with the AEP annual revenue requirement increasing from $537,651,367 to $708,843,770.

The AEP Transmission Companies' Schedule 1A rate will be $.0322 per MWh.

An annual revenue requirement of $141,628,445 for RTEP projects (including true-up and interest) is to be collected under PJM Tariff Schedule 12. The RTEP Project revenue requirement includes:

1. b1465.4 (Rockport Jefferson) of $(409,632)
2. b1465.2 (Rockport Jefferson-MVAR Bank) $1,651,046
3. b2048 (Tanners Creek 345/138 kV transformer) $633,859
4. b1818 (Expand the Allen station) $6,748,773
5. b1819 (Rebuild Robinson Park) $15,386,053
6. b1659 (Sorenson Add 765/345 kV transformer) $7,367,209
7. b1659.13 (Sorenson Exp. Work 765kV) $5,086,462
8. b1659.14 (Sorenson 14miles 765 line) $7,329,473
9. b1465.1 (Add a 3rd 2250 MVA 765/345kV transformer Sullivan) $4,521,337
10. b1465.5 (Sullivan Inst Baker 765kV tsfr) $2,171,058
11. b0570 (Lima-Sterling) $1,744,202
12. b1231 (Wapakoneta-West Moulton) $497,938
13. b1034.1 (South Canton-Wagenhals-Wayview 138 kV) $1,247,005
14. b1034.8 (South Canton Wagenhals Station) $644,408
15. b1864.2 (West Bellaire-Brues 138 kV Circuit) $160,553
16. b1870 (Ohio Central Transformer) $1,025,283
17. b1032.2 (Two 138kV outlets to Delano/Camp Sherman) $(1,965,867)

Attachment 11

Projected Formula Rate for AEP East subsidiaries in PJM

To be Effective January 1, 2019 through December 31, 2019
Docket No ER17-405

Pursuant to PJM OATT Attachment H-14A (Formula Rate Implementation Protocols), AEP has calculated its Projected Transmission Revenue Requirements (PTRR) for the Rate Year beginning January 1, 2019 through December 31, 2019. All the files pertaining to the PTRR are to be posted on the PJM website in PDF format. The first file provides the PTRR and rates for Network transmission service and Scheduling System Control and Dispatch Service (Schedule 1A), and the annual transmission revenue requirement for RTEP projects (Schedule 12). An informational filing will also be submitted to the FERC.

AEP network service rate will decrease effective January 1, 2019 from $34,995.82 per MW per year to $34,720.16 per MW per year with the AEP annual revenue requirement increasing from $758,009,365 to $790,189,172.

The AEP Schedule 1A rate will be $.0279 per MWh.

An annual revenue requirement of $36,964,337 for RTEP projects (including true-up and interest) is to be collected under PJM Tariff Schedule 12. The RTEP Projected revenue requirement includes:

1.	b0839	(Twin Branch) $784,996
2.	b0318	(Amos 765/138 kV Transformer) $1,400,358
3.	b0504	(Hanging Rock) $712,912
4.	b0570	(East Side Lima) $92,799
5.	b1034.1	(Torrey-West Canton) $1,043,665
6.	b1034.6	(138kV circuit South Canton Station) $354,201
7.	b1231	(West Moulton Station) $944,504
8.	b1465.2	(Rockport Jefferson 300 MVAR bank) $68,174
9.	b1465.3	(Rockport Jefferson 765 kV line) $2,256,724
10.	b1712.2	(Altavista-Leesville 138kV line) $280,814
11.	b1864.1	(OPCo Kammer 345/138 kV transformers) $13,243
12.	b1864.2	(West Bellaire-Brues 138 kV circuit) of $120,583
13.	b2020	(Rebuild Amos-Kanawha River) $1,960,008
14.	b2021	(APCo Kanawha River Gen Retirement Upgrades) $310,445
15.	b2017	(APCo Rebuild Sporn-Waterford Muskingum River 345kV line) $1,762,481
16.	b1659.14	(Ft. Wayne Relocate) $283,171
17.	b2048	(Tanners Creek-Transformer Replacement) $85,106
18.	b1818	(Expand the Allen Station) $1,126,789
19.	b1819	(Rebuild Robinson Park 138kV line corridor) $237,287
20.	b1465.4	(Switching imp at Sullivan Jefferson 765kV station) $(100,227)
21.	b2021	(OPCo 345/138kV Transformer) $691,649
22.	b2032	(Rebuild 138kV Elliott Tap-Poston) $16,882
23.	b1034.2	(Loop South Canton-Wayview) $548,715

Projected Formula Rate for AEP East subsidiaries in PJM

To be Effective January 1, 2019 through December 31, 2019
Docket No ER17-405

24.	b1034.7	(Replace circuit breakers Torrey/Wagenhals) $703,989
25.	b1970	(Reconductor Kammer-West Bellaire) $(191,500)
26.	b2018	(Loop Conesville-Bixby 345kV) $2,518,748
27.	b1032.4	(Loop the existing South Canton-Wayview 138kV circuit) $213,667
28.	b1666	(Build an 8 breaker 138kV station Fosteria-East Lima) $448,298
29.	b1957	(Terminate transformer #2 SW Lima) $360,793
30.	b1962	(Add four 765kV breakers Kammer) $203,060
31.	b2019	(Burger 345/138kV Station) $1,045,055
32.	b2017	(OPCo Reconductor Sporn-Waterford-Muskingum River) $937,962
33.	b1032.3	(Convert Ross-Circleville 138kV) $(1,118,069)
34.	b1660	(Install 765/500 kV transformer Cloverdale) $(8,807,088)
35.	b1660.1	(Cloverdale Establish 500 kV station) $4,217,755
36.	b1663.2	(Jacksons-Ferry 765kV breakers) $639,843
37.	b1875	(138 kV Bradley to McClung upgrades) $55,020
38.	b1797.1	(Reconductor Cloverdale-Lexington 500 kV line) $9,517,861
39.	b1712.1	(Altavista-Leesville 138kV line) $30,554
40.	b1032.2	(Two 138kV outlets to Delano&Camp) $(908,174)
41.	b1818	(Expand Allen w/345/138kV xfmr) $83,513
42.	b2687.1	(Install a 450 MVAR SVC Jacksons Ferry 765kV Substation) $8,376,163
43.	b2687.2	(Reactor Replacement at Broadford) $2,419,038
44.	b1870	(Replace Ohio Central Tfmr) $3,160
45.	b1465.5	(Switching Imp at Sullivan Jefferson 765kV stations) $169,229
46.	b2831.1	(Upgrade Tanners Creek Miami Fort 345kV circuit) $67,813
47.	b2833	(Reconductor Maddox Creek East Lima 345kV circuit) $787,895
48.	b2230	(Amos Station retire 3 765kV reactors Amos-Hanging Rock) $194,470

Projected Formula Rate for

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.

To be Effective January 1, 2019
Docket No ER17-405

18. b1034.2 (Loop existing South Canton-Wayview 138kV) $974,175
19. b1034.3 (345/138kV 450 MVA transformer Canton Central) $2,060,635
20. b1970 (Reconductor Kammer-West Bellaire) $(2,501,509)
21. b2018 (Loop Conesville-Bixby 345 kV) $2,063,148
22. b2021 (OHTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $3,219,238
23. b2032 (Rebuild 138kV Elliott Tap Poston line) $575,072
24. b1032.1 (Construct new 345/138kV station Marquis-Bixby) $8,526,455
25. b1032.4 (Install 138/69kV transformer Ross Highland) $959,936
26. b1666 (Build 8 breaker 138kV station Fostoria-East Lima) $5,174,533
27. b1957 (Terminate Transformer #2 SW Lima) $1,124,654
28. b2019 (Establish Burger 345/138kV station) $8,032,362
29. b2017 (OHTCo Rebuild Sporn-Waterford-Muskingum River) $8,078,686
30. b1818 (Allen Station Expansion) $302,816
31. b2833 (Reconductor Maddox Creed-East Lima 345kV circuit) $355,700
32. b1661 (765kV circuit breaker Wyoming station) $(47,980)
33. b1864.1 (Add 2 345/138kV transformers at Kammer) $9,594,870
34. b2021 (WVTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $2,218,901
35. b1948 (New 765/345 interconnection Sporn) $6,474,921
36. b1962 (Add four 765kV breakers Kammer) $2,503,736
37. b2017 (WVTCo Rebuild Sporn-Waterford-Muskingum River) $177,123
38. b2020 (Rebuild Amos-Kanawha River 138 kV corridor) $17,231,085
39. b2022 (Tristate-Kyger Creek 345kV line at Sporn) $496,531
40. b1875 (138 kV Bradley to McClung upgrades) $238,860
41. b2230 (Replace 3 765kV reactors Amos-Hanging Rock) $2,192,546
42. b2423 (Install 300 MVAR shunt reactor Wyoming 765kV station) $3,440,312
43. b1495 (Add 765/345 kV transf. Baker Station) $4,322,480

Attachment 12
PSE&G Formula Rate for January 1, 2019 to December 31, 2019

Attachment 12

Hesser G. McBride, Jr.
Associate General Regulatory Counsel

Law Department
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PSEG
Services Corporation

October 15, 2018

VIA ELECTRONIC FILING

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 2019 Formula Rate Annual Update

Dear Secretary Bose:

Pursuant to the Formula Rate Implementation Protocols ("Protocols") of Public Service Electric and Gas Company ("PSE&G") contained in Attachment H-10B of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("OATT"), PSE&G submits its Formula Rate Annual Update ("Annual Update") for 2019. This 2019 Annual Update sets forth PSE&G's annual transmission revenue requirement calculated in accordance with its Formula Rate for network transmission service under the PJM OATT for the period commencing January 1, 2019 to and including December 31, 2019. The 2019 Annual Update also includes a True-up Adjustment for the 2017 Rate Year (January 1, 2017 to and including December 31, 2017).

In accordance with the Protocols, this submission is provided to the Federal Energy Regulatory Commission ("Commission") for informational purposes only and requires no action by the Commission. As required by the Protocols, PSE&G is also providing a copy of this filing to PJM for posting on the PJM website. Exhibit 1 of this filing includes a copy of PSE&G's 2019 Annual Update. Consistent with the Commission Staff's Guidance on Formula Rate Updates, PSE&G is submitting the formula rate template and additional exhibits in Microsoft Excel format.

In addition to PSE&G's 2019 Annual Update formula rate template, PSE&G also submits Workpaper 1, which contains additional supporting information pursuant to Commission Staff's Guidance on Formula Rate Updates for the computation of accumulated deferred income taxes ("ADIT").

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

Attachment 12

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2019**
	Shaded cells are input cells			
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	33,000,000
2	Total Wages Expense	(Note O)	Attachment 5	207,904,693
3	Less A&G Wages Expense	(Note O)	Attachment 5	7,904,693
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	200,000,000
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**16.5000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	22,375,394,716
7	Common Plant in Service - Electric		(Line 22)	228,215,832
8	Total Plant in Service		(Line 6 + 7)	22,603,610,548
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	4,054,244,063
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	6,208,457
11	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	43,587,119
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	53,591,921
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	4,157,631,559
14	Net Plant		(Line 8 - Line 13)	18,445,978,989
15	Transmission Gross Plant		(Line 31)	12,356,298,172
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**54.6652%**
17	Transmission Net Plant		(Line 43)	11,166,342,138
18	**Net Plant Allocator**		(Line 17 / Line 14)	**60.5354%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	12,258,566,555
20	General	(Note B)	Attachment 5	331,405,374
21	Intangible - Electric	(Note B)	Attachment 5	11,451,940
22	Common Plant - Electric	(Note B)	Attachment 5	228,215,832
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	571,073,146
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	18,700,575
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	29,203,705
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	523,168,866
27	Wage & Salary Allocator		(Line 5)	16.5000%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	86,322,863
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	11,408,754
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	97,731,617
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**12,356,298,172**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	1,136,185,567
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	171,880,645
34	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	97,179,040
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	23,357,435
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	245,702,250
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	6,208,457
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	251,910,707
39	Wage & Salary Allocator		(Line 5)	16.5000%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	41,565,267
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmis	(Note B & J)	Attachment 5	12,205,200
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**1,189,956,033**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**11,166,342,138**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2019**
	Shaded cells are input cells			
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
44	**ADIT net of FASB 106 and 109**	(Note Q)	Attachment 1	-2,644,123,357
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	0
	Abandoned Transmission Projects			
45a	Unamortized Abandoned Transmission Projects	(Note R)	Attachment 5	0
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	21,553,978
	Prepayments			
47	Prepayments	(Note A & Q)	Attachment 5	277,073
	Materials and Supplies			
48	Undistributed Stores Expense	(Note Q)	Attachment 5	0
49	Wage & Salary Allocator		(Line 5)	16.5000%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	29,539,555
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	29,539,555
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	129,886,619
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	16,235,827
	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)**	**(2,576,516,923)**
58	**Rate Base**		(Line 43 + Line 57)	**8,589,825,215**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	110,528,262
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**110,528,262**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	116,449,462
63	Plus: Actual PBOP expense	(Note J)	Attachment 5	32,322,615
64	Less: Actual PBOP expense	(Note O)	Attachment 5	32,322,615
65	Less Property Insurance Account 924	(Note O)	Attachment 5	3,877,140
66	Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	10,559,683
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	3,492,891
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	98,519,749
70	Wage & Salary Allocator		(Line 5)	16.5000%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**16,255,759**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	755,558
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)	755,558
75	Property Insurance Account 924		(Line 65)	3,877,140
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)	3,877,140
78	Net Plant Allocator		(Line 18)	60.5354%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**2,347,041**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**129,886,619**

Attachment 12

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2019**
	Shaded cells are input cells				
	Depreciation & Amortization Expense				
	Depreciation Expense				
81	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	291,319,276
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	28,572,417
83	Less: Amount of General Depreciation Expense Associated with Acct. 397		(Note J & O)	Attachment 5	4,771,700
84	Balance of General Depreciation Expense			(Line 82 - Line 83)	23,800,717
85	Intangible Amortization		(Note A & O)	Attachment 5	11,230,055
86	Total			(Line 84 + Line 85)	35,030,772
87	Wage & Salary Allocator			(Line 5)	16.50%
88	General Depreciation & Intangible Amortization Allocated to Transmission			(Line 86 * Line 87)	5,780,077
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission		(Note J & O)	Attachment 5	1,132,353
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**			(Line 88 + Line 89)	**6,912,431**
91	**Total Transmission Depreciation & Amortization**			**(Lines 81 + 81a + 90)**	**298,231,707**
	Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes		(Note O)	Attachment 2	10,899,920
93	**Total Taxes Other than Income Taxes**			(Line 92)	**10,899,920**
	Return \ Capitalization Calculations				
94	**Long Term Interest**			p117.62.c through 67.c	320,692,877
95	**Preferred Dividends**		enter positive	p118.29.d	0
	Common Stock				
96	Proprietary Capital		(Note P)	Attachment 5	9,339,162,134
97	Less Accumulated Other Comprehensive Income Account 219		(Note P)	Attachment 5	657,984
98	Less Preferred Stock			(Line 106)	0
99	Less Account 216.1		(Note P)	Attachment 5	1,805,139
100	**Common Stock**			(Line 96 - 97 - 98 - 99)	9,336,699,012
	Capitalization				
101	Long Term Debt		(Note P)	Attachment 5	8,250,250,992
102	Less Loss on Reacquired Debt		(Note P)	Attachment 5	57,960,830
103	Plus Gain on Reacquired Debt		(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss		(Note P)	Attachment 5	14,425,336
105	Total Long Term Debt			(Line 101 - 102 + 103 - 104)	8,177,864,827
106	Preferred Stock		(Note P)	Attachment 5	0
107	Common Stock			(Line 100)	9,336,699,012
108	**Total Capitalization**			(Sum Lines 105 to 107)	17,514,563,838
109	Debt %	Total Long Term Debt		(Line 105 / Line 108)	46.69%
110	Preferred %	Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common %	Common Stock		(Line 107 / Line 108)	53.31%
112	Debt Cost	Total Long Term Debt		(Line 94 / Line 105)	0.0392
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)	0.0183
116	Weighted Cost of Preferred	Preferred Stock		(Line 110 * Line 113)	0.0000
117	Weighted Cost of Common	Common Stock		(Line 111 * Line 114)	0.0623
118	**Rate of Return on Rate Base (ROR)**			(Sum Lines 115 to 117)	**0.0806**
119	**Investment Return = Rate Base * Rate of Return**			**(Line 58 * Line 118)**	**692,116,996**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2019
	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	-716,424
126	1/(1-T)			1 / (1 - Line 123)	139.10%
127	Net Plant Allocation Factor			(Line 18)	60.54%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-603,269**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**209,128,664**
130	**Total Income Taxes**			**(Line 128 + Line 129)**	**208,525,396**
	Revenue Requirement				
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	11,166,342,138
132	Total Adjustment to Rate Base			(Line 57)	-2,576,516,923
133	**Rate Base**			(Line 58)	**8,589,825,215**
134	Total Transmission O&M			(Line 80)	129,886,619
135	Total Transmission Depreciation & Amortization			(Line 91)	298,231,707
136	Taxes Other than Income			(Line 93)	10,899,920
137	Investment Return			(Line 119)	692,116,996
138	Income Taxes			(Line 130)	208,525,396
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,339,660,638**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	12,258,566,555
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	12,258,566,555
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,339,660,638
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,339,660,638**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	24,750,242
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,314,910,396**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,339,660,638**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**11,122,380,988**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**12.0447%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**9.4255%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 15	**1.3279%**
	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)	**439,018,246**
155	Increased Return and Taxes			Attachment 4	**964,338,057**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,403,356,303**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**11,122,380,988**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**12.6174%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**9.9982%**
160	**Net Revenue Requirement**			(Line 148)	**1,314,910,396**
161	True-up amount			Attachment 6	**27,631,675**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission			Attachment 7	**6,187,751**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,348,729,822**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**9,978.3**
166	Rate ($/MW-Year)			(Line 164 / 165)	**135,166.52**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**135,166.52**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2019**

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

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2019

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282	(2,673,918,181)	0	(33,514,268)		From Acct. 282 total, below
ADIT-283	0	(7,434,043)	(1,012,425)		From Acct. 283 total, below
ADIT-190	0	0	4,433,603		From Acct. 190 total, below
Subtotal	(2,673,918,181)	(7,434,043)	(30,093,089)		
Wages & Salary Allocator			16.5000%		
Net Plant Allocator		60.5354%			
End of Year ADIT	(2,673,918,181)	(4,500,226)	(4,965,360)	**(2,683,383,767)**	
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(2,594,965,174)	(5,054,538)	(4,843,235)	**(2,604,862,947)**	
Average Beginning and End of Year ADIT	(2,634,441,678)	(4,777,382)	(4,904,297)	**(2,644,123,357)**	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

(7,434,043) < 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
	Total	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
ADIT-190						
ADIT - Contribution In Aid of Construction	30,572,191	30,572,191	0	0	0	Represents the estimated IRC 118 amount (CIAC)
OPEB	152,061,507	0	0	0	152,061,507	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	1,797,096	0	0	0	1,797,096	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	343,910	0	0	0	343,910	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	209,847	209,847	0	0	0	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	26,908,105	0	0	26,908,105	0	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	2,292,598	0	0	0	2,292,598	Various
Subtotal - p234	**214,185,253**	**30,782,038**		**26,908,105**	**156,495,110**	
Less FASB 109 Above if not separately removed	26,908,105			26,908,105		
Less FASB 106 Above if not separately removed	152,061,507				152,061,507	
Total	**35,215,641**	**30,782,038**		**0**	**4,433,603**	

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

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2019

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)	(3,712,901,448)	(1,537,835,152)	(2,142,650,892)	0	(32,415,405)	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)	(618,781,777)	(86,415,624)	(531,267,290)	0	(1,098,863)	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	(324,980,204)	(267,274,356)	(57,600,663)	0	(105,185)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,656,663,429)**	**(1,891,525,132)**	**(2,731,518,844)**	**0**	**(33,619,453)**	
Less FASB 109 Above if not separately removed	(324,980,204)	(267,274,356)	(57,600,663)	0	(105,185)	
Less FASB 106 Above if not separately removed						
Total	**(4,331,683,225)**	**(1,624,250,776)**	**(2,673,918,181)**	**0**	**(33,514,268)**	

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

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2019

A	B	C	D	E	F	G
		Gas, Prod or Other Related	Only Transmission Related			
ADIT-283	*Total*			Plant	Labor	
Environmental Cleanup Costs	(61,165,265)	(61,165,265)	0	0	0	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	8,156,568	8,156,568	0	0	0	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(19,966,405)	(19,966,405)	0	0	0	Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(7,434,043)	-	0	(7,434,043)	0	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(118,940,207)	(118,940,207)	0	0	0	Associated with Pension Liability not in rates
Vacation Pay	(1,012,425)	-	0	0	(1,012,425)	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
Miscellaneous	2,002,394	2,002,394	0	0	0	Miscellaneous Tax Adjustments.
Deferred Gain	(88,859,662)	(88,859,662)	0	0	0	Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(142,204,739)	-	0	(142,204,739)	0	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(429,423,783)**	**(278,772,577)**		**(149,638,782)**	**(1,012,425)**	
Less FASB 109 Above if not separately removed	(142,204,739)			(142,204,739)		
Less FASB 106 Above if not separately removed						
Total	**(287,219,044)**	**(278,772,577)**		**(7,434,043)**	**(1,012,425)**	

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

Attachment 12

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	(2,594,965,174)	0	(32,619,773)		From Acct. 282 total, below
ADIT-283	0	(8,349,727)	0		From Acct. 283 total, below
ADIT-190	0	0	3,266,834		From Acct. 190 total, below
Subtotal	(2,594,965,174)	(8,349,727)	(29,352,938)		
Wages & Salary Allocator			16.5000%		
Net Plant Allocator		60.5354%			
End of Year ADIT	(2,594,965,174)	(5,054,538)	(4,843,235)	**(2,604,862,947)**	

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

(8,349,727) < 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 *ADIT-190*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
ADIT - Contribution In Aid of Construction	33,971,473	33,971,473	0	0	0	Represents the estimated IRC 118 amount (CIAC)
Vacation Pay	3,390	0	0	0	3,390	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	148,945,601	0	0	0	148,945,601	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	2,888,016	0	0	0	2,888,016	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	375,428	0	0	0	375,428	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	-	0	0	0	0	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	248,554	248,554	0	0	0	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	13,454,052	0	0	13,454,052	0	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	577,742,356	577,742,356	0	0	0	Includes the gross-up on excess deferred taxes
Subtotal - p234	**777,628,871**	**611,962,383**		**13,454,052**	**152,212,435**	
Less FASB 109 Above if not separately removed	13,454,052			13,454,052		
Less FASB 106 Above if not separately removed	148,945,601				148,945,601	
Total	**615,229,217**	**611,962,383**		**0**	**3,266,834**	

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 *ADIT- 282*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Depreciation - Liberalized Depreciation (Federal)	(3,921,723,673)	(1,529,009,659)	(2,363,512,870)	0	(29,201,143)	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)	(318,298,498)	(83,427,565)	(231,452,304)	0	(3,418,630)	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)	0	(264,855)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,557,149,523)**	**(1,879,711,580)**	**(2,644,553,315)**	**0**	**(32,884,628)**	
Less FASB 109 Above if not separately removed	(317,127,352)	(267,274,356)	(49,588,141)	0	(264,855)	
Less FASB 106 Above if not separately removed						
Total	**(4,240,022,171)**	**(1,612,437,224)**	**(2,594,965,174)**	**0**	**(32,619,773)**	

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

Attachment 12

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)	0	0	0	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	10,939,295	10,939,295	0	0	0	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(19,421,825)	(19,421,825)	0	0	0	Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(8,349,727)	-	0	(8,349,727)	0	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(107,307,039)	(107,307,039)	0	0	0	Associated with Pension Liability not in rates
Deferred Gain	(66,528,299)	(66,528,299)	0	0	0	Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(137,656,362)	-	0	(137,656,362)	0	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(389,489,223)**	**(243,483,134)**		**(146,006,089)**		
Less FASB 109 Above if not separately removed	(137,656,362)			(137,656,362)		
Less FASB 106 Above if not separately removed						
Total	**(251,832,861)**	**(243,483,134)**		**(8,349,727)**		

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, 2019

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related				
1	Real Estate	22,188,000			Attachment #5
2	***Total Plant Related***	22,188,000	N/A	8,848,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	11,122,823			
4	Federal Unemployment Tax	251,132			
5	New Jersey Unemployment Tax	536,298			
6	New Jersey Workforce Development	525,625			
7					
8	***Total Labor Related***	12,435,878	16.5000%	2,051,920	
	Other Included		***Net Plant Allocator***		
9					
10					
11					
12					
13	***Total Other Included***	0	60.5354%	0	
14	***Total Included (Lines 8 + 14 + 19)***	34,623,878		10,899,920	
	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)**	34,623,878			
24	**Total Other Taxes from p114.14.g - Actual**	34,623,878			
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, 2019

	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		5,040,000
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		10,200,000
7	Professional Services (Note 2)		45,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		7,550,991
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,805,691
10	Gross Revenue Credits	(Sum Lines 1-9)	28,241,682
11	Less line 18	- line 18	(3,491,440)
12	Total Revenue Credits	line 10 + line 11	24,750,242
13	Revenues associated with lines 2, 7, and 9 (Note 2)		5,450,691
14	Income Taxes associated with revenues in line 13		1,532,189
15	One half margin (line 13 - line 14)/2		1,959,251
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		1,959,251
18	Line 13 less line 17		3,491,440

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).

Attachment 12

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	964,338,057
B	100 Basis Point increase in ROE			1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	8,589,825,215
2	**Long Term Interest**		p117.62.c through 67.c	320,692,877
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	9,339,162,134
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	657,984
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	1,805,139
8	Common Stock		(Line 96 - 97 - 98 - 99)	9,336,699,012
	Capitalization			
9	Long Term Debt		Attachment 5	8,250,250,992
10	Less Loss on Reacquired Debt		Attachment 5	57,960,830
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	14,425,336
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	8,177,864,827
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	9,336,699,012
16	Total Capitalization		(Sum Lines 105 to 107)	17,514,563,838
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	46.7%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	53.3%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0392
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)	0.0183
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0000
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0676
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0859**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**737,907,810**

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	-716,424
38	1/(1-T)		1 / (1 - Line 123)	139%
39	Net Plant Allocation Factor		(Line 18)	60.5354%
40	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-603,269**
41	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		227,033,516
42	**Total Income Taxes**			**226,430,247**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 5 - Cost Support - December 31, 2019

Electric / Non-electric Cost Support

				Previous Year	Current Year - 2019													
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric Portion
	Plant Allocation Factors																	
6	Electric Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.104g	21,940,212,019	21,967,426,357	21,993,774,771	22,051,969,698	22,114,308,367	22,233,640,669	22,520,661,059	22,544,771,207	22,569,047,304	22,601,575,344	22,635,933,101	22,673,350,055	23,033,461,355	22,375,394,716	
7	Common Plant in Service - Electric	(Note B)	p356	219,757,382	218,696,109	215,871,494	216,919,197	219,601,760	220,100,465	222,097,836	237,052,398	237,749,771	239,031,422	239,245,834	239,357,991	241,324,158	228,215,832	
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	3,841,768,213	3,878,355,027	3,914,599,090	3,947,783,902	3,982,258,882	4,014,829,800	4,051,620,824	4,087,774,624	4,124,694,718	4,162,054,904	4,199,710,465	4,235,348,870	4,264,373,496	4,054,244,063	
10	Accumulated Intangible Amortization	(Note B)	p200.21c	5,618,327	5,751,248	5,884,168	6,017,088	6,150,008	6,282,929	6,170,681	6,299,582	6,255,065	6,381,123	6,507,181	6,633,239	6,759,297	6,208,457	
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	39,368,191	39,157,891	40,195,093	41,314,438	41,589,427	42,581,324	43,543,503	44,418,846	45,367,295	46,087,072	46,605,377	47,699,549	48,704,545	43,587,119	
12	Accumulated Common Amortization - Electric	(Note B)	p356	51,992,974	52,754,481	50,381,076	51,096,443	51,830,012	52,566,957	52,751,519	53,617,970	54,490,574	55,373,348	56,262,540	56,345,983	57,231,091	53,591,921	
	Plant In Service																	
19	Transmission Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.58.g	11,976,476,249	11,983,919,582	11,992,781,915	12,031,455,248	12,073,176,581	12,176,552,914	12,374,665,247	12,377,277,580	12,381,742,913	12,396,331,246	12,410,119,579	12,428,475,912	12,758,390,245	12,258,566,555	
20	General (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.99.g	329,734,413	330,228,641	331,004,553	329,851,275	331,318,652	328,724,124	329,617,346	330,488,663	331,416,727	331,871,877	333,627,487	334,664,954	335,721,148	331,405,374	
21	Intangible - Electric	(Note B)	p205.5.g	11,647,395	11,647,395	11,647,395	11,647,395	11,647,395	11,647,395	11,406,246	11,406,246	11,235,671	11,235,671	11,235,671	11,235,671	11,235,671	11,451,940	
22	Common Plant in Service - Electric	(Note B)	p356	219,757,382	218,696,109	215,871,494	216,919,197	219,601,760	220,100,465	222,097,836	237,052,398	237,749,771	239,031,422	239,245,834	239,357,991	241,324,158	228,215,832	
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	20,895,453	19,945,044	19,498,710	17,828,637	17,950,603	17,968,576	18,061,605	18,186,605	18,311,605	18,436,605	18,561,605	18,686,605	18,775,825	18,700,575	
25	Common Plant Account 397 -- Communications	(Note B)	p356	29,256,233	29,256,233	29,256,233	29,256,233	29,256,233	29,256,233	29,256,233	29,256,233	29,256,233	29,097,554	29,097,554	29,097,554	29,049,412	29,203,705	
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	12,431,418	12,189,144	11,617,810	11,286,972	11,283,939	11,192,538	11,192,538	11,192,538	11,192,538	11,192,538	11,192,538	11,192,538	11,156,758	11,408,754	
	Accumulated Depreciation																	
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	1,024,866,880	1,043,775,317	1,062,649,480	1,080,777,374	1,097,285,711	1,115,557,801	1,135,018,730	1,153,793,884	1,172,984,968	1,192,678,229	1,211,951,452	1,229,766,388	1,249,306,152	1,136,185,567	
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	172,947,040	172,879,422	173,103,977	171,394,781	172,467,213	169,494,932	170,021,775	170,537,677	171,119,065	171,238,502	172,678,224	173,408,963	173,156,816	171,880,645	
34	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	p356	91,361,165	91,912,372	90,576,169	92,410,881	93,419,439	95,148,281	96,295,023	98,036,815	99,857,869	101,460,420	102,867,917	104,045,532	105,935,636	97,179,040	
35	Accumulated General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	23,246,383	22,607,385	22,468,742	21,092,442	21,655,541	22,130,274	22,683,651	23,270,043	23,854,661	24,283,134	24,875,549	25,470,413	26,008,434	23,357,435	
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	12,656,462	12,515,764	12,041,245	11,804,466	11,895,465	11,897,336	11,990,607	12,083,878	12,177,149	12,270,420	12,363,691	12,456,962	12,514,156	12,205,200	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
2	Total Wage Expense	(Note A)	p354.28b	207,904,693
3	Total A&G Wages Expense	(Note A)	p354.27b	7,904,693
1	Transmission Wages		p354.21b	33,000,000

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			18,902,478	24,205,478	21,553,978

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	1,679,232	1,679,232	1,679,232	1,679,232	16.500%	277,073

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	29,539,555	29,539,555	29,539,555

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	110,528,262
60	Transmission Lease Payments		p321.96.b	0

Property Insurance Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
65	Property Insurance Account 924	(Note O)	p323.185b	3,877,140

Public Service Electric and Gas Company
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Attachment 5 - Cost Support - December 31, 2019

Attachment 12

Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
62	Total A&G Expenses		p323.197b	116,449,462
				-
63	Actual PBOP expense	(Note J)	Company Records	32,322,615
64	Actual PBOP expense	(Note O)	Company Records	32,322,615

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	10,559,683	-
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	755,558	755,558

General & Common Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	EPRI Dues
68	Less EPRI Dues	(Note D & O)	p352-353	0	0

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	3,492,891	-	3,492,891

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	3,492,891	-	3,492,891

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	291,319,276
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	28,572,417
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	4,771,700
85	Depreciation-Intangible	(Note A & O)	p336.1.f	11,230,055
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	1,132,353

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	22,188,000	8,848,000	13.340.000

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.

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 5 - Cost Support - December 31, 2019

Attachment 12

Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2016 End of Year	2017 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	8,774,388,796	9,903,935,472	9,339,162,134
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	816,474	499,494	657,984
99	Account 216.1	(Note P)	p119.53.c&d	3,187,722	422,555	1,805,139
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	7,862,697,345	8,637,804,639	8,250,250,992
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	61,094,172	54,827,487	57,960,830
103	Gain on Reacquired Debt	(Note P)	p113.61.c,d	0	0	0
104	ADIT associated with Gain or Loss on Reacquired Debt	(Note P)	p277.3.k (footnote)	16,982,115	11,868,557	14,425,336
106	Preferred Stock	(Note P)	p112.3.c,d	0	0	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	716,424

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	0	0	0	0	0	0	0	0	0	0	0	0	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)		0

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			0

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	9,978.3

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		

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2019

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	(Year)	TO populates the formula with Year - 1 actual data and calculates the Year - 1 True-Up Adjustment Before Interest
October	(Year)	TO calculates the Interest to include in the Year - 1 True-Up Adjustment
October	(Year)	TO populates the formula with Year + 1 estimated data and Year - 1 True-Up Adjustment

1 No True-Up Adjustment will be included in the Annual Transmission Revenue Requirement for 2008 or 2009 since 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.	1,211,730,993	
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	1,185,164,918	
C	Difference (A-B)	26,566,074	<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	1.04011	
E	True-up Adjustment (C*D)	27,631,675	

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

Month	Yr	Month
January	Year 1	
February	Year 1	
March	Year 1	
April	Year 1	
May	Year 1	0.1000%
June	Year 1	
July	Year 1	
August	Year 1	
September	Year 1	
October	Year 1	
November	Year 1	0.1200%
December	Year 1	
January	Year 2	
February	Year 2	0.1300%
March	Year 2	0.1900%
April	Year 2	0.1900%
May	Year 2	0.1800%
June	Year 2	0.1800%
July	Year 2	0.1900%
August	Year 2	0.1800%
September	Year 2	0.1800%
Average Interest Rate		0.1640%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

	Estimated Additions - 2019															
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Other Projects PIS (monthly additions)									Other Projects PIS (monthly additions)						
Dec-18	11,976,476,249	0	0	0	0	0	0		**Dec-18**	11,976,476,249	0	0	0	0	0	0
Jan	7,443,333	0	0	0	0	0	0		**Jan**	7,443,333	0	0	0	0	0	0
Feb	8,862,333	0	0	0	0	0	0		**Feb**	8,862,333	0	0	0	0	0	0
Mar	38,673,333	0	0	0	0	0	0		**Mar**	38,673,333	0	0	0	0	0	0
Apr	41,721,333	0	0	0	0	0	0		**Apr**	41,721,333	0	0	0	0	0	0
May	103,376,333	0	0	0	0	0	0		**May**	103,376,333	0	0	0	0	0	0
Jun	198,112,333	0	0	0	0	0	0		**Jun**	198,112,333	0	0	0	0	0	0
Jul	2,612,333	0	0	0	0	0	0		**Jul**	2,612,333	0	0	0	0	0	0
Aug	4,465,333	0	0	0	0	0	0		**Aug**	4,465,333	0	0	0	0	0	0
Sep	14,588,333	0	0	0	0	0	0		**Sep**	14,588,333	0	0	0	0	0	0
Oct	13,788,333	0	0	0	0	0	0		**Oct**	13,788,333	0	0	0	0	0	0
Nov	18,356,333	0	0	0	0	0	0		**Nov**	18,356,333	0	0	0	0	0	0
Dec	329,914,333	0	0	0	0	0	0		**Dec**	329,914,333	0	0	0	0	0	0
Total	12,758,390,245	0	0	0	0	0	0		**Total**	**12,758,390,245**	0	0	0	0	0	0
									Average 13 Month Balance	**981,414,634**	0	0	0	0	0	0
									Average 13 Month in service							
									13 Month Average CWIP to Appendix A, line 45							

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Estimated Transmission Enhancement Charges (Before True-Up) - 2019

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)	Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
553,557,618	**1,834,362**	**745,930**	**7,991,547**	**2,026,323**	**2,573,966**	**2,481,329**	**1,517,398**	**663,287**	**2,030,550**	**2,603**	**915,149**	**2,082,990**	**2,163,352**	**7,953,310**	**1,486,909**

Actual Transmission Enhancement Charges - 2017

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)	Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
586,633,835	**2,199,535**	**894,158**	**9,579,601**	**2,429,204**	**3,084,762**	**2,973,432**	**1,818,367**	**794,917**	**2,433,270**	**3,120**	**1,096,394**	**2,495,347**	**2,591,411**	**9,526,626**	**1,781,001**

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

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)	Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
	18,367,317	**22,750**	**11,267**	**107,822**	**30,507**	**39,187**	**18,534**	**23,171**	**10,097**	**23,225**	**39**	**14,096**	**32,165**	**33,499**	**(282,246)**	**23,078**
Interest		1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011

True Up by Project (with interest) -2017

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)	Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
19,104,055	**23,662**	**11,719**	**112,147**	**31,731**	**40,759**	**19,278**	**24,101**	**10,502**	**24,156**	**41**	**14,661**	**33,455**	**34,843**	**(293,567)**	**24,004**

Estimated Transmission Enhancement Charges (After True-Up) - 2019

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)	Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
572,661,672	**1,858,024**	**757,649**	**8,103,694**	**2,058,054**	**2,614,725**	**2,500,607**	**1,541,499**	**673,790**	**2,054,706**	**2,644**	**929,810**	**2,116,445**	**2,198,195**	**7,659,743**	**1,510,913**

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

Estimated Transmission Enhancement Charges (Before True-Up) - 2019

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)	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)
1,922,456	**663,073**	**4,804,942**	**1,674,114**	**2,297,665**	**6,708,529**	**7,844,304**	**1,226,765**	**621,948**	**4,565,861**	**82,379,787**	**37,992,123**	**48,125,248**	**39,055,893**	**69,638,354**	**40,340,555**

Actual Transmission Enhancement Charges - 2017

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)	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)
2,302,728	**794,193**	**5,754,880**	**2,004,944**	**2,751,687**	**8,033,708**	**9,393,425**	**1,468,905**	**747,840**	**5,487,093**	**98,979,324**	**45,496,882**	**57,628,494**	**46,773,815**	**83,447,128**	**47,372,470**

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

Reconciliation by Project (without interest)

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)	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)
29,824	**10,304**	**69,757**	**25,704**	**(4,095)**	**(616,316)**	**112,526**	**19,300**	**9,863**	**73,313**	**1,180,037**	**563,821**	**635,764**	**581,364**	**1,544,975**	**(420,229)**

1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011

True Up by Project (with interest)-2017

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)	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)
31,020	**10,717**	**72,555**	**26,735**	**(4,259)**	**(641,038)**	**117,040**	**20,074**	**10,259**	**76,254**	**1,227,370**	**586,437**	**661,265**	**604,683**	**1,606,946**	**(437,085)**

Estimated Transmission Enhancement Charges (After True-Up) - 2019

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)	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)
1,953,476	**673,790**	**4,877,498**	**1,700,850**	**2,293,406**	**6,067,491**	**7,961,344**	**1,246,839**	**632,207**	**4,642,115**	**83,607,157**	**38,578,560**	**48,786,513**	**39,660,576**	**71,245,300**	**39,903,470**

Public Service Electric and Gas Company
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Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

Estimated Transmission Enhancement Charges (Before True-Up) - 2019

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)
20,259,634	**7,333,080**	**5,418,467**	**19,099,824**	**14,512,271**	**7,651,848**	**5,614,480**	**10,287,504**	**5,653,720**	**5,653,720**	**5,335,765**	**5,498,421**	**3,578,725**	**2,808,568**	**3,125,434**	**3,125,434**

Actual Transmission Enhancement Charges - 2017

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)
23,733,009	**5,198,758**	**3,294,965**	**1,226,916**	**-**	**-**	**1,226,916**	**1,226,916**	**2,658,611**	**2,658,611**	**3,723,870**	**3,723,870**	**3,942,807**	**3,294,965**	**3,685,670**	**3,685,670**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

Reconciliation by Project (without interest)

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)
414,171	**1,999,208**	**95,416**	**136,575**	**-**	**-**	**(237,130)**	**136,575**	**750,046**	**750,046**	**986,770**	**986,770**	**98,841**	**3,294,965**	**279,991**	**279,991**
1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011

True Up by Project (with interest)-2017

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)
430,784	**2,079,399**	**99,243**	**142,053**	**-**	**-**	**(246,642)**	**142,053**	**780,131**	**780,131**	**1,026,350**	**1,026,350**	**102,805**	**3,427,131**	**291,222**	**291,222**

Estimated Transmission Enhancement Charges (After True-Up) - 2019

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)
20,690,418	**9,412,479**	**5,517,710**	**19,241,877**	**14,512,271**	**7,651,848**	**5,367,838**	**10,429,557**	**6,433,851**	**6,433,851**	**6,362,116**	**6,524,772**	**3,681,530**	**6,235,699**	**3,416,657**	**3,416,657**

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

Estimated Transmission Enhancement Charges (Before True-Up) - 2019

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)	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)
1,813,204	**1,813,178**	**2,408,461**	**1,615,108**	**1,324,570**	**2,124,521**	**4,937,889**	**3,547,715**	**123,362**	**2,592,047**	**17,362,581**	**2,607,459**	0	0	0	0

Actual Transmission Enhancement Charges - 2017

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)	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)
1,227,172	**1,227,153**	**1,684,077**	0	**1,586,839**	**2,542,906**	**1,582,248**	**4,250,525**	**147,691**	**21,554**	**2,475,231**	0	**43,159**	**1,723,268**	**829,190**	**11,692,332**

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

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)	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)
136,831	**136,812**	**(3,225,280)**	0	**20,927**	**64,250**	**93,648**	**93,375**	**147,691**	**21,554**	**2,475,231**	0	**(476,643)**	**(577,456)**	**(257,931)**	**3,234,401**
1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011

True Up by Project (with interest)-2017

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)	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)
142,320	**142,300**	**(3,354,650)**	0	**21,767**	**66,827**	**97,405**	**97,120**	**153,615**	**22,419**	**2,574,516**	0	**(495,762)**	**(600,619)**	**(268,277)**	**3,364,137**

Estimated Transmission Enhancement Charges (After True-Up) - 2019

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)	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)
1,955,524	**1,955,478**	**(946,189)**	**1,615,108**	**1,346,337**	**2,191,349**	**5,035,294**	**3,644,836**	**276,977**	**2,614,466**	**19,937,097**	**2,607,459**	**(495,762)**	**(600,619)**	**(268,277)**	**3,364,137**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

Estimated Transmission Enhancement Charges (Before True-Up) - 2019

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)	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)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Actual Transmission Enhancement Charges - 2017

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)	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)
9,031,610	**4,902,694**	**2,000,778**	**5,839,024**	**752,918**	**752,918**	**1,072,332**	**1,072,332**	**91,333**	**2,823**	**23,661**	**10,803**	**456,263**	**455,980**	**2,983,144**	**731,664**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2019

Reconciliation by Project (without interest)

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)	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)
1,866,304	**426,517**	**19,034**	**358,863**	**(184,646)**	**(184,646)**	**(155,816)**	**(155,816)**	**(106,562)**	**(83,017)**	**(107,057)**	**(123,117)**	**(37,269)**	**(37,584)**	**1,291,724**	**(202,345)**

1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011	1.04011

True Up by Project (with interest) -2017

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)	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)
1,941,164	**443,625**	**19,797**	**373,258**	**(192,052)**	**(192,052)**	**(162,066)**	**(162,066)**	**(110,837)**	**(86,347)**	**(111,351)**	**(128,056)**	**(38,764)**	**(39,092)**	**1,343,537**	**(210,461)**

Estimated Transmission Enhancement Charges (After True-Up) - 2019

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)	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)
1,941,164	**443,625**	**19,797**	**373,258**	**(192,052)**	**(192,052)**	**(162,066)**	**(162,066)**	**(110,837)**	**(86,347)**	**(111,351)**	**(128,056)**	**(38,764)**	**(39,092)**	**1,343,537**	**(210,461)**

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

			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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%
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

21		Invest Yr	Branchburg (B0130) Ending	Branchburg (B0130) Depreciation or Amortization	Branchburg (B0130) Revenue	Kittatinny (B0134) Ending	Kittatinny (B0134) Depreciation or Amortization	Kittatinny (B0134) Revenue	Essex Aldene (B0145) Ending	Essex Aldene (B0145) Depreciation or Amortization	Essex Aldene (B0145) Revenue	New Freedom Trans.(B0411) Ending	New Freedom Trans.(B0411) Depreciation or Amortization	New Freedom Trans.(B0411) 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	15,229,564	491,562	2,199,535	6,259,896	192,120	894,158	67,061,488	2,058,755	9,579,601	16,949,826	528,306	2,429,204
45	W Increased ROE	2017	15,229,564	491,562	2,199,535	6,259,896	192,120	894,158	67,061,488	2,058,755	9,579,601	16,949,826	528,306	2,429,204
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
44	W 11.68 % ROE	2019	14,246,440	491,562	1,834,362	5,875,657	192,120	745,930	62,943,978	2,058,755	7,991,547	15,893,213	528,306	2,026,323
45	W Increased ROE	2019	14,246,440	491,562	1,834,362	5,875,657	192,120	745,930	62,943,978	2,058,755	7,991,547	15,893,213	528,306	2,026,323

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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 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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%
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	3,084,762	21,066,812	610,820	2,973,432	12,874,060	374,561	1,818,367	5,610,124	165,750	794,917
45	W Increased ROE	2017	21,772,741	642,982	3,084,762	21,066,812	610,820	2,973,432	12,874,060	374,561	1,818,367	5,610,124	165,750	794,917
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
44	W 11.68 % ROE	2019	20,486,777	642,982	2,573,966	19,845,171	610,820	2,481,329	12,124,939	374,561	1,517,398	5,278,624	165,750	663,287
45	W Increased ROE	2019	20,486,777	642,982	2,573,966	19,845,171	610,820	2,481,329	12,124,939	374,561	1,517,398	5,278,624	165,750	663,287

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		**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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%
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	17,235,419	500,344	2,433,270	21,880	666	3,120	7,831,801	218,069	1,096,394	17,871,199	491,119	2,495,347
45	W Increased ROE	2017	17,235,419	500,344	2,433,270	21,880	666	3,120	7,831,801	218,069	1,096,394	17,871,199	491,119	2,495,347
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
44	W 11.68 % ROE	2019	16,234,731	500,344	2,030,550	20,548	666	2,603	7,395,662	218,069	915,149	16,888,961	491,119	2,082,990
45	W Increased ROE	2019	16,234,731	500,344	2,030,550	20,548	666	2,603	7,395,662	218,069	915,149	16,888,961	491,119	2,082,990

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		**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		9.43%	9.43%	9.43%	9.43%	
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%	
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	2,591,411	68,524,248	1,841,734	9,526,626	12,822,540	342,972	1,781,001	16,570,216	444,403	2,302,728
45		W Increased ROE	2017	18,612,436	504,054	2,591,411	68,524,248	1,841,734	9,526,626	12,822,540	342,972	1,781,001	16,570,216	444,403	2,302,728
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
44		W 11.68 % ROE	2019	17,604,328	504,054	2,163,352	64,840,780	1,841,734	7,953,310	12,136,595	342,972	1,486,909	15,681,410	444,403	1,922,456
45		W Increased ROE	2019	17,604,328	504,054	2,163,352	64,840,780	1,841,734	7,953,310	12,136,595	342,972	1,486,909	15,681,410	444,403	1,922,456

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

			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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			9.43%		
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	794,193	41,541,291	1,096,087	5,754,880	14,509,330	377,744	2,004,944	19,921,276	517,546	2,751,687
45		W Increased ROE	2017	5,724,913	152,152	794,193	41,541,291	1,096,087	5,754,880	14,509,330	377,744	2,004,944	19,921,276	517,546	2,751,687
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
44		W 11.68 % ROE	2019	5,420,608	152,152	663,073	39,349,118	1,096,087	4,804,942	13,753,841	377,744	1,674,114	18,886,184	517,546	2,297,665
45		W Increased ROE	2019	5,420,608	152,152	663,073	39,349,118	1,096,087	4,804,942	13,753,841	377,744	1,674,114	18,886,184	517,546	2,297,665

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		**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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			10.14%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		62,938,142			72,376,948			11,276,183			5,857,687		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,498,527			1,723,261			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		
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										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	58,272,563	1,498,527	8,033,708	68,392,049	1,723,359	9,393,425	10,703,887	268,481	1,468,905	5,036,479	139,469	704,302
45		W Increased ROE	2017	58,272,563	1,498,527	8,033,708	68,392,049	1,723,359	9,393,425	10,703,887	268,481	1,468,905	5,036,479	139,469	747,840
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
44		W 11.68 % ROE	2019	55,275,530	1,498,527	6,708,529	64,941,230	1,723,261	7,844,304	10,166,926	268,481	1,226,765	4,757,542	139,469	587,891
45		W Increased ROE	2019	55,275,530	1,498,527	6,708,529	64,941,230	1,723,261	7,844,304	10,166,926	268,481	1,226,765	4,757,542	139,469	621,948

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.14%			10.14%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		40,538,248			721,881,272			356,333,540			438,746,971		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		965,196			17,187,649			8,484,132			10,446,356		
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			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	5,163,491	677,132,437	17,186,557	93,125,945	330,033,388	8,484,132	45,496,882	420,701,437	10,447,458	57,628,494
45		W Increased ROE	2017	37,435,134	965,196	5,487,093	677,132,437	17,186,557	98,979,324	330,033,388	8,484,132	45,496,882	420,701,437	10,447,458	57,628,494
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
44		W 11.68 % ROE	2019	35,504,741	965,196	4,311,700	642,834,128	17,187,649	77,778,058	313,065,125	8,484,132	37,992,123	399,754,320	10,446,356	48,125,248
45		W Increased ROE	2019	35,504,741	965,196	4,565,861	642,834,128	17,187,649	82,379,787	313,065,125	8,484,132	37,992,123	399,754,320	10,446,356	48,125,248

Public Service Electric and Gas Company
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			Formula Line		
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5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
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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		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)
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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.57%	9.57%	9.43%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		370,007,352	625,126,924	350,991,604	180,222,157
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,809,699	14,883,974	8,356,943	4,291,004
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	2013	2016	2016

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	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	338,516,483	8,809,699	46,773,815	602,065,287	14,885,514	82,406,233	342,609,998	8,356,943	46,780,141	176,296,656	4,203,493	23,733,009
45	W Increased ROE	2017	338,516,483	8,809,699	46,773,815	602,065,287	14,885,514	83,447,128	342,609,998	8,356,943	47,372,470	176,296,656	4,203,493	23,733,009
46	W 11.68 % ROE	2018	329,702,206	8,809,690	40,364,207	587,359,389	14,890,244	71,104,128	0	0	0	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	0	0	0	168,355,336	4,162,710	20,262,866
44	W 11.68 % ROE	2019	320,897,093	8,809,699	39,055,893	572,224,877	14,883,974	68,819,099	334,253,055	8,356,943	39,862,005	169,419,235	4,291,004	20,259,634
45	W Increased ROE	2019	320,897,093	8,809,699	39,055,893	572,224,877	14,883,974	69,638,354	334,253,055	8,356,943	40,340,555	169,419,235	4,291,004	20,259,634

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		64,274,999			47,416,059			164,576,485			124,541,303		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,530,357			1,128,954			3,918,488			2,965,269		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
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	42,938,400	916,068	5,198,758	24,558,823	583,272	3,294,965	14,747,154	214,966	1,226,916			
45		W Increased ROE	2017	42,938,400	916,068	5,198,758	24,558,823	583,272	3,294,965	14,747,154	214,966	1,226,916			
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
44		W 11.68 % ROE	2019	61,564,011	1,530,357	7,333,080	45,509,601	1,128,954	5,418,467	161,066,436	3,918,488	19,099,824	122,507,954	2,965,269	14,512,271
45		W Increased ROE	2019	61,564,011	1,530,357	7,333,080	45,509,601	1,128,954	5,418,467	161,066,436	3,918,488	19,099,824	122,507,954	2,965,269	14,512,271

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		**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)**		
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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		65,676,775			48,470,597			88,662,709			49,111,440		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,563,733			1,154,062			2,111,017			1,169,320		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2018			2015			2015			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	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				14,747,154	214,966	1,226,916	14,747,154	214,966	1,226,916	31,239,305	465,743	2,658,611
45		W Increased ROE	2017				14,747,154	214,966	1,226,916	14,747,154	214,966	1,226,916	31,239,305	465,743	2,658,611
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
44		W 11.68 % ROE	2019	64,591,882	1,563,733	7,651,848	47,322,821	1,154,062	5,614,480	86,748,462	2,111,017	10,287,504	47,577,259	1,169,320	5,653,720
45		W Increased ROE	2019	64,591,882	1,563,733	7,651,848	47,322,821	1,154,062	5,614,480	86,748,462	2,111,017	10,287,504	47,577,259	1,169,320	5,653,720

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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 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)**
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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		49,111,440	46,581,405	46,581,405	31,820,773
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,169,320	1,109,081	1,109,081	757,637
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2015	2015	2015	2016

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	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	31,239,305	465,743	2,658,611	43,917,206	652,295	3,723,870	43,917,206	652,295	3,723,870	30,818,452	697,633	3,942,807
45	W Increased ROE	2017	31,239,305	465,743	2,658,611	43,917,206	652,295	3,723,870	43,917,206	652,295	3,723,870	30,818,452	697,633	3,942,807
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
44	W 11.68 % ROE	2019	47,577,259	1,169,320	5,653,720	44,843,021	1,109,081	5,335,765	46,568,719	1,109,081	5,498,421	29,930,334	757,637	3,578,725
45	W Increased ROE	2019	47,577,259	1,169,320	5,653,720	44,843,021	1,109,081	5,335,765	46,568,719	1,109,081	5,498,421	29,930,334	757,637	3,578,725

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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.

				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)**		
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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		24,983,113			27,828,619			27,828,619			15,828,121		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		594,836			662,586			662,586			376,860		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
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	24,558,823	583,272	3,294,965	27,091,682	653,428	3,685,670	27,091,682	653,428	3,685,670	14,750,891	214,966	1,227,172
45		W Increased ROE	2017	24,558,823	583,272	3,294,965	27,091,682	653,428	3,685,670	27,091,682	653,428	3,685,670	14,750,891	214,966	1,227,172
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
44		W 11.68 % ROE	2019	23,486,597	594,836	2,808,568	26,129,595	662,586	3,125,434	26,129,595	662,586	3,125,434	15,238,900	376,860	1,813,204
45		W Increased ROE	2019	23,486,597	594,836	2,808,568	26,129,595	662,586	3,125,434	26,129,595	662,586	3,125,434	15,238,900	376,860	1,813,204

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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 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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		15,828,121	21,021,567	13,915,127	12,081,133
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		376,860	500,513	331,313	287,646
19	Months in service for depreciation expense from			13.00	13.00	13.00	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	14,750,613	214,966	1,227,153	18,339,519	295,246	1,684,077				11,583,248	287,798	1,586,839
45	W Increased ROE	2017	14,750,613	214,966	1,227,153	18,339,519	295,246	1,684,077				11,583,248	287,798	1,586,839
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
44	W 11.68 % ROE	2019	15,238,622	376,860	1,813,178	20,242,376	500,513	2,408,461	13,620,433	331,313	1,615,108	11,001,247	287,646	1,324,570
45	W Increased ROE	2019	15,238,622	376,860	1,813,178	20,242,376	500,513	2,408,461	13,620,433	331,313	1,615,108	11,001,247	287,646	1,324,570

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		**Mickleton-Gloucester 230kV Circuit (B2139)**			**Ridge Road 69kV Breaker Station (B1255)**			**Cox's Corner-Lumberton 230kV Circuit (B1787)**			**Sewaren Switch 230kV Conversion (B2276)**		
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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		19,278,867			42,781,896			32,029,640			0		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		459,021			1,018,617			762,610			0		
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		
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	18,586,669	458,892	2,542,906	39,858,124	277,639	1,582,248	31,074,276	763,146	4,250,525	0	0	0
45		W Increased ROE	2017	18,586,669	458,892	2,542,906	39,858,124	277,639	1,582,248	31,074,276	763,146	4,250,525	0	0	0
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	0	0	0
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	0	0	0
44		W 11.68 % ROE	2019	17,670,135	459,021	2,124,521	41,581,532	1,018,617	4,937,889	29,548,579	762,610	3,547,715	0	0	0
45		W Increased ROE	2019	17,670,135	459,021	2,124,521	41,581,532	1,018,617	4,937,889	29,548,579	762,610	3,547,715	0	0	0

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		**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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		1,108,058	22,218,229	149,126,087	22,302,697
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		26,382	529,005	3,550,621	531,017
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2016	2018	2017	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												
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	1,081,675	26,382	147,691	2,060,962	3,775	21,554	75,384,047	433,473	2,475,231			
45	W Increased ROE	2017	1,081,675	26,382	147,691	2,060,962	3,775	21,554	75,384,047	433,473	2,475,231			
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
44	W 11.68 % ROE	2019	1,028,911	26,382	123,362	21,887,850	529,005	2,592,047	146,538,027	3,550,621	17,362,581	22,030,024	531,017	2,607,459
45	W Increased ROE	2019	1,028,911	26,382	123,362	21,887,850	529,005	2,592,047	146,538,027	3,550,621	17,362,581	22,030,024	531,017	2,607,459

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

			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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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) (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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.14%			10.14%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		0			0			0			0		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		0			0			0			0		
19	Months in service for depreciation expense from														
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				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	0		0	15,544,417		1,822,213	0		0	81,558,947		9,560,846
41		W Increased ROE	2015	0		0	15,544,417		1,955,563	0		0	81,558,947		9,560,846
42		W 11.68 % ROE	2016	0		0	0		0	0		0	0		0
43		W Increased ROE	2016	0		0	0		0	0		0	0		0
44		W 11.68 % ROE	2017	0		0	0		0	0		0	0		0
45		W Increased ROE	2017	0		0	0		0	0		0	0		0
46		W 11.68 % ROE	2018	0		0	0		0	0		0	0		0
47		W Increased ROE	2018	0		0	0		0	0		0	0		0
44		W 11.68 % ROE	2019	0		0	0		0	0		0	0		0
45		W Increased ROE	2019	0		0	0		0	0		0	0		0

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

			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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		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)		
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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			9.57%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		0			0			0			0		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		0			0			0			0		
19	Months in service for depreciation expense from														
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				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	0		0	0		0	232,789,181		31,313,982
41		W Increased ROE	2015	204,760		24,003	0		0	0		0	232,789,181		31,772,294
42		W 11.68 % ROE	2016	0		0	0		0	0		0	103,162,268		11,805,242
43		W Increased ROE	2016	0		0	0		0	0		0	103,162,268		11,982,038
44		W 11.68 % ROE	2017	0		0	0		0	0		0	0		0
45		W Increased ROE	2017	0		0	0		0	0		0	0		0
46		W 11.68 % ROE	2018	0		0	0		0	0		0	0		0
47		W Increased ROE	2018	0		0	0		0	0		0	0		0
44		W 11.68 % ROE	2019	0		0	0		0	0		0	0		0
45		W Increased ROE	2019	0		0	0		0	0		0	0		0

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%
				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		**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)**		
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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%			9.43%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment			0			0			0			0	
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp			0			0			0			0	
19	Months in service for depreciation expense from														
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	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	0		0	281,839		43,159	20,566,179		1,723,268	14,568,795		829,190
45		W Increased ROE	2017	0		0	281,839		43,159	20,566,179		1,723,268	14,568,795		829,190
46		W 11.68 % ROE	2018	0		0	327,500		31,344	3,373,416		322,857	4,386,778		419,841
47		W Increased ROE	2018	0		0	327,500		31,344	3,373,416		322,857	4,386,778		419,841
44		W 11.68 % ROE	2019	0		0	0		0	0		0	0		0
45		W Increased ROE	2019	0		0	0		0	0		0	0		0

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		**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	"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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment			0			0			0			0	
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp			0			0			0			0	
19	Months in service for depreciation expense from														
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	136,377,541		11,692,332	115,588,044		9,031,610	60,812,051		4,902,694	26,861,722		2,000,778
45		W Increased ROE	2017	136,377,541		11,692,332	115,588,044		9,031,610	60,812,051		4,902,694	26,861,722		2,000,778
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
44		W 11.68 % ROE	2019	0		0	0		0	0		0	0		0
45		W Increased ROE	2019	0		0	0		0	0		0	0		0

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		**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)**		
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		9.43%			9.43%			9.43%			9.43%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%			9.43%			9.43%			9.43%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		0			0			0			0		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		0			0			0			0		
19	Months in service for depreciation expense from														
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	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	56,811,725		5,839,024	2,241,295		752,918	2,241,295		752,918	211,045		1,072,332
45		W Increased ROE	2017	56,811,725		5,839,024	2,241,295		752,918	2,241,295		752,918	211,045		1,072,332
46		W 11.68 % ROE	2018	13,879,908		1,328,392	84,069		8,046	80,847		7,738	0		0
47		W Increased ROE	2018	13,879,908		1,328,392	84,069		8,046	80,847		7,738	0		0
44		W 11.68 % ROE	2019	0		0	0		0	0		0	0		0
45		W Increased ROE	2019	0		0	0		0	0		0	0		0

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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 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)**
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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		0	0	0	0
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		0	0	0	0
19	Months in service for depreciation expense from						
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	211,045		1,072,332	891,553		91,333	25,172		2,823	210,981		23,661
45	W Increased ROE	2017	211,045		1,072,332	891,553		91,333	25,172		2,823	210,981		23,661
46	W 11.68 % ROE	2018	0		0	1,421,804		136,075	7,334		702	352,578		33,744
47	W Increased ROE	2018	0		0	1,421,804		136,075	7,334		702	352,578		33,744
44	W 11.68 % ROE	2019	0		0	0		0	0		0	0		0
45	W Increased ROE	2019	0		0	0		0	0		0	0		0

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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 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)**
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		9.43%	9.43%	9.43%	9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%	9.43%	9.43%	9.43%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		0	0	0	0
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		0	0	0	0
19	Months in service for depreciation expense from						
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	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	96,330		10,803	10,559		456,263	8,039		455,980	22,702,321		2,983,144
45		W Increased ROE	2017	96,330		10,803	10,559		456,263	8,039		455,980	22,702,321		2,983,144
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
44		W 11.68 % ROE	2019	0		0	0		0	0		0	0		0
45		W Increased ROE	2019	0		0	0		0	0		0	0		0

Attachment 12

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2019

			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	9.43%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.00%
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	1.33%

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		9.43%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.43%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		0
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		0
19	Months in service for depreciation expense from			
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	12,011,798		731,664	$ 578,780,093		$ 578,780,093
45	W Increased ROE	2017	12,011,798		731,664	$ 586,633,835	$ 586,633,835		$ 7,853,742
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
44	W 11.68 % ROE	2019	0		0	$ 547,369,866		$ 547,369,866
45	W Increased ROE	2019	0		0	$ 553,557,618	$ 553,557,618		$ 6,187,751

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

Attachment 12

Public Service Electric and Gas Company
Projected Costs of Plant in Forecasted Rate Base and In-Service Dates
12 Months Ended December 31, 2019

Required Transmission Enhancements

Upgrade ID	**RTEP Baseline Project Description**	**Estimated/Actual Project Cost (thru 2019) ***	**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
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	$ 62,938,142	Dec-11
b1399	Aldene-Springfield Rd. Conversion	$ 72,376,948	Dec-12
b1590	Upgrade Camden-Richmond 230kV Circuit	$ 11,276,183	Apr-13
b1588	Uprate EaglePoint-Gloucester 230kV Circuit	$ 12,081,133	May-11
b2139	Build Mickleton-Gloucester Corridor Ultimate Design	$ 19,278,867	Dec-13
b1255	Ridge Road 69kV Breaker Station	$ 42,781,896	Jun-16
b1787	New Cox's Corner-Lumberton 230kV Circuit	$ 32,029,640	Nov-13
b0376	Install Conemaugh 250MVAR Cap Bank	$ 1,108,058	Mar-16
b1589	Reconfigure Kearny- Loop in P2216 Ckt	$ 22,218,229	May-18
b2146	Reconfigure Brunswick Sw-New 69kVCkt-T	$ 149,126,087	Oct-17
b2702	350 MVAR Reactor Hopatcong 500kV	$ 22,302,697	Jun-18
b0489.5-b0489.15	Susquehanna Roseland Breakers	$ 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)	$ 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)	$ 721,881,272	Mar-15
b1156	Burlington - Camden 230kV Conversion	$ 356,333,540	Oct-14
b1398 - b1398.7	Mickleton-Gloucester-Camden	$ 438,746,971	Jun-15
b1154	North Central Reliability (West Orange Conversion)	$ 370,007,352	Jun-15
b1304.1-b1304.4	Northeast Grid Reliability Project	$ 625,126,924	Jun-15
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades	$ 180,222,157	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 64,274,999	May-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 47,416,059	May-16
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	$ 48,470,597	Dec-15
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	$ 49,111,440	Dec-15
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	$ 49,111,440	Dec-15
b2436.84	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades	$ 46,581,405	Dec-15
b2436.85	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades	$ 46,581,405	Dec-15
b2436.90	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	$ 31,820,773	May-16
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades	$ 27,828,619	May-16
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades	$ 15,828,121	Dec-15
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades	$ 15,828,121	Dec-15
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades	$ 21,021,567	Jul-16
	Total	**$ 4,114,265,532**	

**** May vary from original PJM Data due to updated information.***

Attachment 12

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

2018 EOY Amount	(2,594,965,174)	A
2019 EOY Amount	(2,673,918,181)	B

Account 282, Transmission Plant-related Liberalized Depreciation, for 2019

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	2018	Dec						(2,594,965,174)	A
2	2019	Jan	(3,844,304)	335	91.78%	(3,528,334)	(2,598,493,508)		
3	2019	Feb	(3,844,304)	307	84.11%	(3,233,428)	(2,601,726,936)		
4	2019	Mar	(3,844,304)	276	75.62%	(2,906,926)	(2,604,633,862)		
5	2019	Apr	(3,844,304)	246	67.40%	(2,590,956)	(2,607,224,818)		
6	2019	May	(3,844,304)	215	58.90%	(2,264,453)	(2,609,489,271)		
7	2019	Jun	(3,844,304)	185	50.68%	(1,948,483)	(2,611,437,754)		
8	2019	Jul	(3,844,304)	154	42.19%	(1,621,980)	(2,613,059,734)		
9	2019	Aug	(3,844,304)	123	33.70%	(1,295,478)	(2,614,355,212)		
10	2019	Sep	(3,844,304)	93	25.48%	(979,508)	(2,615,334,720)		
11	2019	Oct	(3,844,304)	62	16.99%	(653,005)	(2,615,987,725)		
12	2019	Nov	(3,844,304)	32	8.77%	(337,035)	(2,616,324,760)		
13	2019	Dec	(3,844,304)	1	0.27%	(10,532)	(2,616,335,292)		
		Total	(46,131,647)			(21,370,118)			

14	Projected 2019 Liberalized Depreciation based on ADIT Proration Methodology:	(21,370,118)	
15	Plus: Projected 2019 ADIT associated with Liberalized Deprecation not subject to Proration Methodology:	(57,582,889)	
16	Projected 2019 EOY Federal and State Liberalized Depreciation ADIT included in the FERC Formula Filing:	(2,673,918,181)	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.

Attachment 12

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

2018 EOY Amount	(32,619,773)	A
2019 EOY Amount	(33,514,268)	B

Account 282, Common Plant-related Liberalized Depreciation, for 2019

	(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	2018	Dec						(32,619,773)	A
2	2019	Jan	36,764	335	91.78%	33,742	(32,586,031)		
3	2019	Feb	36,764	307	84.11%	30,922	(32,555,109)		
4	2019	Mar	36,764	276	75.62%	27,800	(32,527,309)		
5	2019	Apr	36,764	246	67.40%	24,778	(32,502,531)		
6	2019	May	36,764	215	58.90%	21,656	(32,480,875)		
7	2019	Jun	36,764	185	50.68%	18,634	(32,462,241)		
8	2019	Jul	36,764	154	42.19%	15,511	(32,446,730)		
9	2019	Aug	36,764	123	33.70%	12,389	(32,434,341)		
10	2019	Sep	36,764	93	25.48%	9,367	(32,424,974)		
11	2019	Oct	36,764	62	16.99%	6,245	(32,418,729)		
12	2019	Nov	36,764	32	8.77%	3,223	(32,415,506)		
13	2019	Dec	36,764	1	0.27%	101	(32,415,405)		
		Total	441,170			204,368			

14	Projected 2019 Liberalized Depreciation based on ADIT Proration Methodology:	204,368	
15	Plus: Projected 2019 ADIT associated with Liberalized Deprecation not subject to Proration Methodology:	(1,098,863)	
16	Projected 2019 EOY Federal and State Liberalized Depreciation ADIT included in the FERC Formula Filing:	(33,514,268)	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.

Attachment 13

JCP&L Settlement Offer for January 1, 2019 to December 31, 2019

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SINGAPORE
TOKYO
TORONTO

December 21, 2017

By eTariff

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

Re: PJM Interconnection, L.L.C., Docket No. ER17-217-003
Offer of Settlement

Dear Secretary Bose:

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, Jersey Central Power & Light Company ("JCP&L") hereby submits an Offer of Settlement ("Settlement") in the above-referenced proceeding. This Settlement is intended to resolve all issues set for hearing in the above-captioned proceeding involving JCP&L's transmission formula rate under the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff.[1]

In accordance with Rule 602(c)(1), this Settlement filing consists of the following documents:

1. This transmittal letter;
2. An Explanatory Statement; and
3. The Settlement, including copies of *pro forma* tariff records and other appendices.

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[1] This filing is being submitted by PJM on behalf of JCP&L as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. JCP&L requested that PJM submit this filing in the eTariff system as part of PJM's electronic Intra-PJM Tariff.

JCP&L certifies that it is serving a complete copy of the Settlement on all parties to the above-referenced proceeding. In accordance with Commission regulations, comments on the settlement package are due twenty (20) days from the date of filing, making comments due January 10, 2018. Reply comments are due January 22, 2018.

Respectfully submitted,

/s/ Matthew W.S. Estes

Counsel for
Jersey Central Power & Light Company

cc: All parties
Enclosures

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER17-217-003**
Jersey Central Power & Light Co.	**)**	

EXPLANATORY STATEMENT

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.602 (2017), Jersey Central Power & Light Co. ("JCP&L"), on behalf of the Settling Parties,[1] submits this explanatory statement in support of the Offer of Settlement ("Settlement") to resolve the issues set for hearing and settlement judge procedures in the above-captioned docket. It is the Settling Parties' understanding that no other participants in these proceedings oppose the Settlement.

This Explanatory Statement is provided solely to comply with Rule 602(c)(1)(ii) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602(c)(1)(ii). Except as otherwise defined herein, the capitalized terms used in this Explanatory Statement have the meanings set forth in the related Settlement. This Explanatory Statement is not intended to, and does not alter any of the provisions of the Settlement. In the event of an inconsistency between the Explanatory Statement and the Settlement, the Settlement shall control.

I. PROCEDURAL HISTORY

On October 28, 2016, in Docket No. ER17-217-000, PJM Interconnection, L.L.C. ("PJM"), on behalf of JCP&L, filed under section 205 of the Federal Power Act ("FPA") for approval of a transmission formula rate template ("Template") and formula rate protocols

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[1] The Settling Parties are JCP&L and New Jersey Division of the Rate Counsel ("NJ Rate Counsel"); New Jersey Board of Public Utilities ("NJ BPU"), the Public Power Association of New Jersey ("PPANJ"), and the U.S. Department of Defense/Federal Executive Agencies ("DOD").

("Protocols") to establish transmission rates for the JCPL zone under the PJM Open Access Transmission Tariff ("PJM Tariff"). JCP&L's filing included a revised Exhibit H-4 and new Attachments H-4A (Template) and H-4B (Protocols) to the PJM Tariff. JCP&L requested an effective date for its filing of January 1, 2017.

Motions to intervene and comments, protests, and motions for suspension and hearing were filed in this proceeding by certain parties, including, among others, all Settling Parties. On December 5, 2016, JCP&L submitted an answer to the protests and motions, and certain parties filed answers to JCP&L's answer.

On December 28, 2016, the Commission issued a letter finding JCP&L's filing to be deficient and requesting additional information. PJM Interconnection, L.L.C., Docket No. ER17-217-000, Deficiency Letter (issued Dec. 28, 2016) ("December 28 Letter"). On January 10, 2017, JCP&L submitted its response providing the additional information requested in the December 28 Letter, as well as certain revisions to the Template required in the December 28 Letter. Several parties submitted comments and protests to JCP&L's response, and JCP&L filed an answer to those pleadings.

On March 10, 2017, the Commission issued a letter order accepting JCP&L's filing subject to refund, suspending the filing for five months to be effective on June 1, 2017, and setting the proceeding for hearing and settlement judge procedures. *Jersey Cent. Power & Light Co.*, 158 FERC ¶ 62,186 (2017) ("March 10 Order"). On April 10, 2017, JCP&L filed a motion for reconsideration or, in the alternative, request for rehearing of the March 10 Order, asking for reconsideration or rehearing of the decision to suspend the filing for five months.

On March 16, 2017, the Chief Administrative Law Judge ("ALJ") appointed ALJ Philip C. Baten as the Settlement Judge. In-person settlement proceedings were held with Judge Baten on April 11, 2017, June 6, 2017, July 14, 2017, August 17, 2017, September 21, 2017, and October 26, 2017. In addition, numerous telephonic technical conferences were held among JCP&L, the parties, and FERC Trial Staff; and the parties and FERC Trial Staff submitted, and JCP&L responded to, several sets of data requests seeking information on JCP&L's filing.

During the settlement proceedings, the parties and FERC Trial Staff submitted several settlement proposals and counterproposals.

As a result of these settlement efforts, during a settlement call held on November 9, 2017, an agreement-in-principle to resolve all issues in this proceeding was reached among FERC Trial Staff and the Settling Parties. The agreement-in-principle has resulted in the Offer of Settlement and Settlement Agreement that is being filed today.

II. SUMMARY OF SETTLEMENT

The provisions of the Settlement are summarized below.

Article 1 is an introductory section, identifying the parties to the Settlement and stating that it will be filed with the Commission.

Article 2 provides that the Settlement resolves all issues raised in this proceeding and sets forth the terms and conditions of the Settlement.

> Section 2.1 provides that the filed formula rate Template and Protocols will be replaced by a black box stated rate with revenue requirements ("Settlement Revenue Requirements"). JCP&L's stated revenue requirement for its Network Integration Transmission Service ("NITS") shall be $135 million/year and JCP&L's stated revenue requirement for its projects listed on Schedule 12 of the PJM OATT shall be an average of $20 million/year aggregating $51.67 million over the 31 months from June 1, 2017 through December 31, 2019. JCP&L's stated total aggregate revenue requirement for its

projects listed on Schedule 12 will be allocated over three periods as specified in the Settlement. The Settlement Revenue Requirements fully reflect the Settling Parties' view of the impact of any potential legislative tax reform and the Settling Parties agree that no future adjustment to those revenue requirements is necessary if any Federal tax reform is enacted.

Section 2.2 provides that the Template and Protocols that were accepted, subject to refund, in the March 10 Order as Attachments H-4A and H-4B respectively, shall be withdrawn as of the date that the Settlement is approved by the Commission and shall have no effect thereafter.

Section 2.3 establishes a rate moratorium, and provides that, with limited exceptions, no Settling Party (individually or collectively) shall seek an effective date earlier than January 1, 2020 in any filing made under sections 205 or 206 of the FPA proposing any changes to, or challenging the justness and reasonableness of, this Settlement Agreement or the Settlement Revenue Requirements. The exceptions are that: (a) JCP&L may file for adders to the Settlement Revenue Requirements for certain large projects placed in service with a January 1, 2019 or later in-service date; (b) JCP&L may file pursuant to FPA section 205 solely to recover the costs of an Extraordinary Storm (as defined in the Settlement) in addition to recovering the Settlement Revenue Requirements; and (c) in the event the Commission or any non-Settling Party files under section 206 of the FPA to re-open the stated rate to seek changes to reflect the impact of legislative tax reform, JCP&L shall be entitled, at its discretion, to make a filing under FPA section 205 to change its rates during the moratorium period. The other Settling Parties shall have full rights under FPA section 205 to oppose any such filings by JCP&L as not being just and reasonable.

Section 2.4 provides that the rates to existing NITS customers for transmission over low voltage facilities (*i.e.*, at voltages below 34.5 kv delta) ("Low Voltage Customers") shall be fixed at the existing levels for the duration of the transmission stated rate moratorium. In addition, a new Attachment H-4A shall be added to the PJM Tariff that addresses rates charged for the provision of transmission service over JCP&L's low voltage transmission facilities

Section 2.5 provides that, as of December 31, 2019, the account balances of the three regulatory assets for (a) storm costs, (b) vegetation management costs, and (c) formula rate development costs that JCP&L included in its filed Formula Rate Template will be deemed to be $0.00 for FERC accounting purposes and deemed fully recovered for ratemaking purposes.

Section 2.6 establishes JCP&L's depreciation rates.

Section 2.7 provides that the effective date of the Settlement Revenue Requirements shall be June 1, 2017. An amount equal to the difference between the rates charged by PJM and the rates that would have been charged under the Settlement, plus interest calculated pursuant to section 35.19a(a)(2) of the Commission's regulations, for the period from June 1, 2017 through the date the Settlement Revenue Requirements as reflected in PJM billings for NITS and Schedule 12 charges (the "Settlement Billing Date") will be ratably credited against the revenue requirements for NITS and Schedule 12 for the remaining months in the calendar year in which the Settlement Billing Date occurs.

Section 2.8 provides that, within thirty days of the Commission's approval of the Settlement, JCP&L will withdraw its April 10, 2017 Motion for Reconsideration or, in the Alternative, Request for Rehearing.

Section 2.9 provides that JCP&L shall file a motion with the Chief Administrative Law Judge requesting that the Settlement Revenue Requirements be accepted as interim rates pursuant to 18 C.F.R. § 375.307(a)(1)(iv), effective January 1, 2018, pending the Commission's approval of the Settlement. In the event the Settlement is withdrawn, then JCP&L's existing revenue requirements shall go into effect and the difference between the amounts collected under the Interim Rate and the amounts that would have been collected under the existing revenue requirements for such period that the Interim Rate was in effect shall be reflected in JCP&L's revenue requirements.

Article 3 sets forth miscellaneous provisions. Notably, Article 3 provides that the Settlement is an integrated package and that the individual provisions thereof are non-severable. However, if any party submits comments opposing specific aspects of the Settlement, if all the Settling Parties agree and so inform the Commission, the Commission may sever some or all of the issues raised in the comments. Further, Article 3 provides that the standard of review for modifications to the Settlement proposed by any Settling Party thereto after it is approved by the Commission is the public interest standard and that the standard of review for any changes proposed by third parties and the Commission acting *sua sponte* shall be the just and reasonable standard.

III. INFORMATION REQUIRED BY THE CHIEF ADMINISTRATIVE LAW JUDGE'S DECEMBER 15, 2016 NOTICE REGARDING SETTLEMENT AGREEMENTS

1. Does the settlement affect other pending cases?

The Settling Parties are not aware of any pending cases that would be affected by the Settlement.

2. Does the settlement involve issues of first impression?

The Settling Parties are not aware of any issues of first impression raised by the Settlement.

3. Does the settlement depart from Commission precedent?

The Settling Parties are not aware of any departures from Commission precedent.

4. Does the settlement seek to impose a standard of review other than the ordinary just and reasonable standard with respect to any changes to the settlement that might be sought by either a third party or the Commission acting sua sponte?

Upon the Commission's approval of the Settlement, the applicable standard of review for any changes proposed by the Settling Parties shall be the public interest standard and the standard of review for any changes proposed by third parties and the Commission acting *sua sponte* shall be the just and reasonable standard.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Jersey Central Power & Light Co.	))	Docket No. ER17-217-003

SETTLEMENT AGREEMENT
AND
OFFER OF SETTLEMENT

This Settlement Agreement ("Settlement" or "Agreement"), submitted to the Federal Energy Regulatory Commission ("FERC" or the "Commission") for approval as an Offer of Settlement pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602 (2017), is entered into as of December 19, 2017 by Jersey Central Power & Light Company ("JCP&L), New Jersey Division of the Rate Counsel ("NJ Rate Counsel"); New Jersey Board of Public Utilities ("NJ BPU"), the Public Power Association of New Jersey ("PPANJ"), and the U.S. Department of Defense/Federal Executive Agencies ("DOD") (each a "Settling Party" and collectively, the "Settling Parties").

This Settlement Agreement is submitted as an Offer of Settlement to resolve completely, upon the Commission's acceptance of this Settlement without condition or modification unacceptable to the Settling Parties, all issues in this proceeding. Subject to the conditions set forth in this Settlement, including the acceptance by the Commission of this Settlement in its entirety without condition or modification unacceptable to the Settling Parties, and with the understanding that each term of this Settlement is in consideration and support of every other term, the Settling Parties agree as follows.

ARTICLE I

Background

1.1. On October 28, 2016, in Docket No. ER17-217-000, PJM Interconnection, L.L.C. ("PJM"), on behalf of JCP&L, filed under section 205 of the Federal Power Act ("FPA") for approval of a transmission formula rate template ("Template") and formula rate protocols ("Protocols") to establish transmission rates for the JCPL zone under the PJM Open Access Transmission Tariff ("PJM Tariff"). JCP&L's filing included a revised Exhibit H-4 and new Attachments H-4A (Template) and H-4B (Protocols) to the PJM Tariff. JCP&L requested an effective date for its filing of January 1, 2017.

1.2. Motions to intervene and comments, protests, and motions for suspension and hearing were filed in this proceeding by certain parties, including, among others, all Settling Parties. On December 5, 2016, JCP&L submitted an answer to the protests and motions, and certain parties filed answers to JCP&L's answer.

1.3. On December 28, 2016, the Commission issued a letter finding JCP&L's filing to be deficient and requesting additional information. *PJM Interconnection, L.L.C.*, Docket No. ER17-217-000, Deficiency Letter (issued Dec. 28, 2016) ("December 28 Letter"). On January 10, 2017, JCP&L submitted its response providing the additional information requested in the December 28 Letter, as well as certain revisions to the Template required in the December 28 Letter. Several parties submitted comments and protests to JCP&L's response, and JCP&L filed an answer to those pleadings.

1.4. On March 10, 2017, the Commission issued a letter order accepting JCP&L's filing subject to refund, suspending the filing for five months to be effective on June 1, 2017, and setting the proceeding for hearing and settlement judge procedures. *Jersey Cent. Power & Light Co.*, 158 FERC ¶ 62,186 (2017) ("March 10 Order"). On

April 10, 2017, JCP&L filed a motion for reconsideration or, in the alternative, request for rehearing of the March 10 Order, asking for reconsideration or rehearing of the decision to suspend the filing for five months.

1.5. On March 16, 2017, the Chief Administrative Law Judge ("ALJ") appointed ALJ Philip C. Baten as the Settlement Judge. In-person settlement proceedings were held with Judge Baten on April 11, 2017, June 6, 2017, July 14, 2017, August 17, 2017, September 21, 2017, and October 26, 2017. In addition, numerous telephonic technical conferences were held among JCP&L, the parties, and FERC Trial Staff; and the parties and FERC Trial Staff submitted, and JCP&L responded to, several sets of data requests seeking information on JCP&L's filing.

1.6 During the settlement proceedings, the parties and FERC Trial Staff submitted several settlement proposals and counterproposals.

1.7. As a result of these settlement efforts, during a settlement call held on November 9, 2017, an agreement-in-principle to resolve all issues in this proceeding was reached among FERC Trial Staff and the Settling Parties. The agreement-in-principle has resulted in the Offer of Settlement and Settlement Agreement that is being filed today.

1.8. No party indicated that it would oppose the Offer of Settlement, either on the November 9, 2017 settlement call or thereafter. Consequently, to the knowledge of the Settling Parties, this Offer of Settlement is uncontested.

NOW, THEREFORE, in consideration of the promises and the mutual covenants and agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Settling Parties, intending to be legally bound, agree as follows:

ARTICLE II

Terms of the Settlement Agreement

The Settling Parties hereby settle and resolve all issues between them involving the matters raised in Docket No. ER17-217, on the terms set forth below.

2.1 Black Box Stated Revenue Requirement. The Settling Parties agree that JCP&L's proposed Formula Rate shall be replaced by a black box stated rate with revenue requirements, as follows:

(a) JCP&L's stated revenue requirement for its Network Integration Transmission Service ("NITS") shall be $135 million/year.

(b) JCP&L's stated revenue requirement for its projects listed on Schedule 12 of the PJM OATT shall be an average of $20 million/year aggregating $51.67 million over the 31 months from June 1, 2017 through December 31, 2019. JCP&L's stated total aggregate revenue requirement for TEC will be allocated over three periods:

(i) For rates effective from June 1, 2017 through December 31, 2017, JCP&L's stated revenue requirement collected for TEC will be $7,433,693 based on an annual revenue requirement of $12,743,474.
(ii) For rates effective from January 1, 2018 through December 31, 2018, JCP&L's stated annual revenue requirement for TEC will be $21,605,928.
(iii) For rates effective from January 1, 2019, JCP&L's stated annual revenue requirement for TEC will be $22,627,046.

(c) The revenue requirements provided for in parts (a) and (b) of this Section 2.1 (the "Settlement Revenue Requirements") are the product of a black box settlement, and they are not based on any agreed-upon assumptions about the elements of the rate, including return on equity, recovery of regulatory assets, or the functionalization of JCP&L's costs or plant. Nothing in this

Settlement Agreement is intended to establish any principle or precedent with respect to any issue in these proceedings except as explicitly set forth herein. Accordingly, neither this Settlement Agreement nor JCP&L's performance in accordance herewith shall be deemed to constitute an admission or concession as to (i) the justness of any cost, charge, cost-of-service component, or ratemaking method, or (ii) any contention or position that was asserted, or that could have been asserted, in this docket. The Commission's approval of this Settlement Agreement shall not constitute a determination by the Commission as to the merits of any allegation or contention that was made or that could have been made in these proceedings.

(d) The Settlement Revenue Requirements fully reflect the Settling Parties' view of the impact of any potential legislative tax reform and the Settling Parties agree that no future adjustment to those revenue requirements is necessary if any Federal tax reform is enacted. Therefore, there shall be no re-opener or adjustment to the Settlement Agreement or the Settlement Revenue Requirements effective prior to January 1, 2020 to reflect the recently introduced Tax Cuts and Jobs Act, or any other legislation reducing the corporate income tax rate or otherwise affecting the amount of Federal taxes owed by JCP&L.

(e) Attached as Exhibit 1 is the revised version of the tariff sheets affected by this Settlement Agreement, and attached as Exhibit 2 is a marked version of those tariff sheets showing the changes made to the currently-effective tariff.

2.2 **Withdrawal of Template and Protocols**. The Settling Parties agree that the Template and Protocols that were accepted, subject to refund, in the March 10 Order as Attachments H-4A and H-4B respectively, shall be withdrawn as of the date that this Settlement Agreement is approved by the Commission and shall have no effect thereafter.

2.3. **Rate Moratorium.**

(a) Except as provided in Sections 2.3(b), (c) and (d) below, no Settling Party (individually or collectively) shall seek an effective date earlier than January 1, 2020 in any filing made under sections 205 or 206 of the FPA proposing any changes to, or challenging the justness and reasonableness of, this Settlement Agreement or the Settlement Revenue Requirements. Nor shall any Settling Party support such a request by another entity.

(b) JCP&L may make limited filings pursuant to FPA section 205, and the other Settling Parties shall have full rights under FPA section 205 to oppose JCP&L's rate filing as not being just and reasonable, for adders to the Settlement Revenue Requirements for projects with a January 1, 2019 or later in-service date that would take effect during the period of the rate moratorium, as follows: (1) filings pursuant to FERC Order No. 679 for incentives associated with a project with a projected cost of $100 million or more; or (2) filings associated with PJM Regional Transmission Expansion Planning ("RTEP") project(s) (costing $50 million or more in the aggregate) to the extent that, prior to January 1, 2020, JCP&L is required to construct and place such projects in service.

(c) In the event of an Extraordinary Storm (defined below) during the period in which the Settlement Revenue Requirements are in effect, JCP&L may file pursuant to FPA section 205 solely to recover the costs of an Extraordinary Storm in addition to recovering the Settlement Revenue Requirements. For purposes of this Agreement, an Extraordinary Storm shall be defined as a single event (wind, tornado, hurricane, tropical storm, tropical depression, rain, snow, hail, sleet, ice, lightning, flood, fire resulting from any of these natural perils, and similar causes) that results in JCP&L incurring costs of greater than $1,500,000 (net of any insurance receipts from third-party coverage) to remediate storm damage to the JCP&L transmission system.[1] The other Settling Parties shall have full rights under FPA section 205 to oppose JCP&L's rate filing as not being just and reasonable. Any Extraordinary Storm costs below this $1,500,000 threshold are deemed to be recovered through the Settlement Revenue Requirements.

(d) No Party may support any action initiated during the moratorium period by the Commission or any non-Settling Party under section 206 of the FPA to re-open the stated rate to seek changes to reflect the impact of legislative tax reform, nor shall any Party be entitled to initiate its own section 206 action or otherwise take any action during the moratorium period to support any change to Settlement Revenue Requirements; except that only if the Commission and/or any non-Settling Party initiates an action to re-open the

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[1] The definition of Extraordinary Storm as used herein does not incorporate the definition of an "Extraordinary Item" as defined in General Instruction No. 7 of the Commission's Uniform System of Accounts.

stated rate shall JCP&L be entitled, at its discretion, to make a filing under FPA section 205 to change its rates during the moratorium period. The other Settling Parties shall have full rights under FPA section 205 to oppose JCP&L's rate filing as not being just and reasonable.

(e) Notwithstanding paragraph 2.3(d), Settling Parties are free to take any position in generic Commission proceedings not specifically applicable to JCP&L regarding the effect of legislative tax reform on existing transmission rates, provided that no Settling Party may take a position in such generic proceeding specifically as to the Settlement Revenue Requirements during the moratorium period.

2.4 Rates for Transmission Over Low Voltage Facilities.

(a) The rates to existing NITS customers for transmission over low voltage facilities (*i.e.*, at voltages below 34.5 kv delta) ("Low Voltage Customers") shall be fixed at the existing levels for the duration of the transmission stated rate moratorium. Such Low Voltage Customers include the New Jersey Boroughs of Butler, Lavallette, Madison, Pemberton and Seaside Heights. These rates are already fixed pursuant to individual PJM NITS (Attachment F) agreements through May 31, 2019.

(b) A new Attachment H-4A shall be added to the PJM Tariff that addresses rates charged for the provision of transmission service over JCP&L's low voltage transmission facilities, as reflected on Exhibits 1 and 2 to this Settlement Agreement.

2.5. Regulatory Assets. As of December 31, 2019, the account balances of the three regulatory assets for (a) storm costs, (b) vegetation management costs, and (c) formula rate development costs that JCP&L included in its filed Formula Rate Template will be deemed to be $0.00 for FERC accounting purposes and deemed fully recovered for ratemaking purposes.

2.6. Depreciation. The Settling Parties agree to the depreciation and amortization rates filed in this proceeding by JCP&L and shown in Exhibit 3 to this Settlement Agreement, which shall be deemed accepted for use by JCP&L in setting rates in this and all other JCP&L rate filings unless and until the Commission approves a change in the depreciation and/or amortization rates pursuant to FPA section 205 or 206.

2.7. Effective Date and Refunds. The effective date of the Settlement Revenue Requirements shall be June 1, 2017. Within 60 days of the issuance of a Final Order approving this Settlement Agreement, JCP&L shall coordinate with PJM to revise the monthly billing amounts for NITS and TEC to reflect the settlement. An amount equal to the difference between the rates charged by PJM and the rates that would have been charged under this Settlement Agreement, plus interest calculated pursuant to section 35.19a(a)(2) of the Commission's regulations, for the period from June 1, 2017 through the date the Settlement Revenue Requirements as reflected in PJM billings for NITS and Schedule 12 charges (the "Settlement Billing Date") will be ratably credited against the revenue requirements for NITS and Schedule 12 for the remaining months in the calendar year in which the Settlement Billing Date occurs. For purposes of this Settlement Agreement, an order shall be deemed to be a "Final Order" as of the date rehearing is denied by the Commission, or if rehearing is not sought, as of the date on which the right to seek Commission rehearing expires.

2.8 Withdrawal of Request for Reconsideration/Rehearing. Within thirty days of the issuance of a Final Order approving this Agreement, JCP&L will withdraw its April 10, 2017 Motion for Reconsideration or, in the Alternative, Request for Rehearing.

2.9 Motion for Interim Rates. Concurrently with the filing of this Settlement Agreement with the Commission, JCP&L shall file a motion with the Chief Administrative Law Judge requesting that the Settlement Revenue Requirements be accepted as interim rates pursuant to 18 C.F.R. § 375.307(a)(1)(iv), effective January 1, 2018, pending the Commission's approval. The Settling Parties agree that, in the event this Settlement Agreement is withdrawn pursuant to Section 3.4, then JCP&L's existing revenue requirements shall go into effect and the difference between the amounts collected under the Interim Rate and the amounts that would have been collected under the existing revenue requirements for such period that the Interim Rate was in effect shall be reflected in JCP&L's revenue requirements.

ARTICLE III

Miscellaneous Provisions

3.1. *Scope of the Agreement.* This Settlement Agreement, including the exhibits hereto, constitutes the entire agreement among the Settling Parties with respect to the subject matter addressed herein, and supersedes any and all prior or contemporaneous representations, agreements, instruments and understandings between them, whether written or oral. There are no other oral understandings, terms or conditions, and none of the Settling Parties has relied upon any representation, express or implied, not contained in this Settlement.

3.2. *Non-Severability*. The Settling Parties agree and understand that the various provisions of this Settlement Agreement are not severable and, and except for Article 3 of this Settlement Agreement, shall not become operative unless and until the Commission issues a Final Order accepting or approving this Settlement Agreement as to all its terms and conditions without modification.

3.3. *Effectiveness of Settlement.* Except for Article 3 of this Settlement Agreement, the provisions hereof shall become effective when accepted or approved by the Commission without modification or condition through a Final Order. Article 3 of this Settlement Agreement shall go into effect upon the execution of the Settlement Agreement by all of the Settling Parties.

3.4 *Reservations.* No Settling Party shall be bound or prejudiced by any part of this Settlement Agreement unless and until it becomes effective in the manner provided by Section 3.3 hereof. If this Settlement Agreement is not accepted or approved in its entirety without modification or conditions it shall be deemed withdrawn, shall not be considered to be part of the record in this proceeding, and shall be null and void and of no force and effect, unless all of the Settling Parties otherwise agree in writing to such modification or condition.

3.5. *No Admissions or Precedent.* This Settlement Agreement is submitted pursuant to Rule 602, and is inadmissible as evidence in any proceeding, and of no effect unless it is approved and made effective as to all of its terms and conditions without modification. Further, the making of this Settlement Agreement and its acceptance or approval by the Commission shall not in any respect constitute an admission by any Settling Party, or a determination by the Commission, that any allegation or contention in these proceedings, or concerning any of the foregoing matters, is true or valid. In consideration of all elements of this negotiated settlement, no element of this Settlement Agreement constitutes precedent or should be deemed to be a "settled practice" as that term was interpreted and applied in *Public Service Commission of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980).

3.6. *Settlement Discussions.* The discussions between and among the Settling Parties that have produced this Settlement Agreement have been conducted with the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, that all offers of settlement and discussions relating thereto shall be privileged and confidential, shall be without prejudice to the position of any Settling Party or participant presenting any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

3.7. *Further Assurances*. Each Settling Party shall cooperate with and support, and shall not take any action inconsistent with: (i) the filing of this Settlement Agreement with the Commission, and (ii) efforts to obtain Commission acceptance or approval of the Settlement Agreement. No Settling Party shall take any actions that are inconsistent with the provisions of this Settlement Agreement.

3.8. *Waiver*. No provision of this Settlement Agreement may be waived except through a writing signed by an authorized representative of the waiving Settling Party. Waiver of any provisions of this Settlement Agreement shall not be deemed to waive any other provision.

3.9. *Modifications/Standard of Review*. The standard of review for any modifications to this Settlement Agreement, set forth in a written amendment executed by all of the Settling Parties shall be the just and reasonable standard. The standard of review for any modifications to this Settlement Agreement requested by a Settling Party other than those set forth in a written amendment executed by all of the Settling Parties shall be the "public interest" standard set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as clarified in *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County, Washington*, 554 U.S. 527 (2008), and refined in *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 558 U.S. 165, 174-75 (2010). The standard of review for any changes proposed by third parties and the Commission acting *sua sponte* shall be the just and reasonable standard.

3.10. *Successors and Assigns.* This Settlement Agreement is binding upon and for the benefit of the Settling Parties and their successors and assigns.

3.11. *Captions.* The captions in this Settlement Agreement are for convenience only and are not a part of this Settlement Agreement and do not in any way limit or amplify the terms and provisions of this Settlement Agreement and shall have no effect on its interpretation.

3.12. *Ambiguities Neutrally Construed*. This Settlement Agreement is the result of negotiations among, and has been reviewed by, each Settling Party and its respective counsel. Accordingly, this Settlement Agreement shall be deemed to be the product of each Settling Party, and no ambiguity shall be construed in favor of or against any Settling Party.

3.13. *Authorization*. Each person executing this Settlement Agreement on behalf of a Settling Party represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to authorize this Settlement to be executed on behalf of, the Settling Party that he or she represents.

3.14. *Notices*. All notices, demands, and other communications hereunder shall be in writing and shall be delivered to each Settling Party's "Corporate Official" as found on the Commission's website at http://www.ferc.gov/docs-filing/corp-off.asp or the representatives of each Settling Party on the official service list in Docket No. ER17-211.

3.15. *Counterparts.* This Settlement Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

[SIGNATURES ON NEXT PAGE]

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ______________________ Date: Dec. 19, 2017

Counsel for JCP+L

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ______________________ Date: __________

NEW JERSEY BOARD OF PUBLIC UTILITIES

By: ______________________ Date: __________

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ______________________ Date: __________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: ______________________ Date: __________

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ________________________ Date: __________

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ________________________ Date: 19-Dec-2017

Stephen C. Pearson
Attorney for Rate Counsel

NEW JERSEY BOARD OF PUBLIC UTILITIES

By: ________________________ Date: __________

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ________________________ Date: __________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: ________________________ Date: __________

Attachment 13

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ______________________ Date: __________

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ______________________ Date: __________

NEW JERSEY BOARD OF PUBLIC UTILITIES

CHRISTOPHER S. PORRINO
ATTORNEY GENERAL OF NEW JERSEY

By: Carol M Date: 12/19/17
Carolyn A. McIntosh
Deputy Attorney General

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ______________________ Date: __________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: ______________________ Date: __________

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: __________________________ Date: ____________

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: __________________________ Date: ____________

NEW JERSEY BOARD OF PUBLIC UTILITIES

By: __________________________ Date: ____________

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: Matthew D__________________________ Date: ____________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: __________________________ Date: ____________

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ______________________ Date: __________

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ______________________ Date: __________

NEW JERSEY BOARD OF PUBLIC UTILITIES

By: ______________________ Date: __________

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ______________________ Date: __________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: ______________________ Date: 12/18/17

EXHIBIT 1

Pro Forma Settlement Tariff Sheets JCP&L's PJM Tariff Attachments H-4, H-4A, and H-4B, and Schedule 12-Appendix (Clean Format)

ATTACHMENT H-4

Annual Transmission Rates -- Jersey Central Power & Light Company for Network Integration Transmission Service

1. The annual transmission revenue requirement for Network Integration Transmission Service is $135,000,000. Attachment H-4A sets forth the rates for deliveries that utilize Jersey Central Power & Light Company ("JCP&L") distribution facilities at voltages below 34.5 kV delta. The transmission revenue requirement reflects the cost of providing transmission service over the 34.5 kV delta and higher transmission facilities of JCP&L.
2. The revenue requirements in this attachment shall be effective until amended by JCP&L or modified by the Commission.
3. In addition to the revenue requirement set forth in paragraph 1 above, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse JCP&L for applicable sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT H-4A
Other Supporting Facilities -- Jersey Central Power & Light Company

As provided in Attachment H-4, section 1, service utilizing facilities at voltages below 34.5 kV delta to serve certain New Jersey municipal utilities will be provided at rates determined on a case-by-case basis and stated in existing NITS Agreements under Attachment F through the expiration of such agreements on May 31, 2019. Commencing on June 1, 2019, the rates for such service shall be as follows:

Borough of Butler, New Jersey: $0.1121/kW-Month

Borough of Lavallette, New Jersey: $2.3784/kW-Month

Borough of Madison, New Jersey: $0.0570/kW-Month

Borough of Pemberton, New Jersey: $1.1081/kW-Month

Borough of Seaside Heights, New Jersey: $1.2459/kW-Month

The above rates will be applied to the each of the New Jersey boroughs' monthly sixty (60) minute coincident billing demands measured at the time of JCP&L's system peak each month.

ATTACHMENT H-4B

[Reserved]

SCHEDULE 12 – APPENDIX

(4) Jersey Central Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0123	Add 180 MVAR of distributed capacitors. 65 MVAR in northern JCPL and 115 MVAR in southern JCPL		JCPL (100%)
b0124.1	Add a 72 MVAR capacitor at Kittatinny 230 kV		JCPL (100%)
b0124.2	Add a 130 MVAR capacitor at Manitou 230 kV		JCPL (100%)
b0132	Reconductor Portland – Kittatinny 230 kV with 1590 ACSS		JCPL (100%)
b0132.1	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Kittatinny bus		JCPL (100%)
b0132.2	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Portland bus		JCPL (100%)
b0173	Replace a line trap at Newton 230kV substation for the Kittatinny-Newton 230kV circuit		JCPL (100%)
b0174	Upgrade the Portland – Greystone 230kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $1,442,372 2018: $1,273,748 2019: $1,235,637	JCPL (35.40%) / Neptune* (5.67%) / PSEG (54.37%) RE (2.94%) / ECP** (1.62%)
b0199	Greystone 230kV substation: Change Tap of limiting CT and replace breaker on the Greystone Whippany (Q1031) 230kV line		JCPL (100%)
b0200	Greystone 230kV substation: Change Tap of limiting CT on the West Wharton Greystone (E1045) 230kV line		JCPL (100%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0202	Kittatinny 230kV substation: Replace line trap on Kittatinny Pohatcong (L2012) 230kV line; Pohatcong 230kV substation: Change Tap of limiting CT on Kittatinny Pohatcong (L2012) 230kV line		JCPL (100%)
b0203	Smithburg 230kV Substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line; East Windsor 230kV substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line		JCPL (100%)
b0204	Install 72Mvar capacitor at Cookstown 230kV substation		JCPL (100%)
b0267	Reconductor JCPL 2 mile portion of Kittatinny – Newton 230 kV line		JCPL (100%)
b0268	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $734,194 2018: $646,180 2019: $628,066	JCPL (61.77%) / Neptune* (3%) / PSEG (32.73%) / RE (1.45%) / ECP** (1.05%)

* Neptune Regional Transmission System, LLC

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0279.1	Install 100 MVAR capacitor at Glen Gardner substation		JCPL (100%)
b0279.2	Install MVAR capacitor at Kittatinny 230 kV substation		JCPL (100%)
b0279.3	Install 17.6 MVAR capacitor at Freneau 34.5 kV substation		JCPL (100%)
b0279.4	Install 6.6 MVAR capacitor at Waretown #1 bank 34.5 kV substation		JCPL (100%)
b0279.5	Install 10.8 MVAR capacitor at Spottswood #2 bank .4.5 kV substation		JCPL (100%)
b0279.6	Install 6.6 MVAR capacitor at Pequannock N bus 34.5 kV substation		JCPL (100%)
b0279.7	Install 6.6 MVAR capacitor at Haskell P bus 34.5 kV substation		JCPL (100%)
b0279.8	Install 6.6 MVAR capacitor at Pinewald #2 Bank 34.5 kV substation		JCPL (100%)
b0279.9	Install 6.6 MVAR capacitor at Matrix 34.5 kV substation		JCPL (100%)
b0279.10	Install 6.6 MVAR capacitor at Hamburg Boro Q Bus 34.5 kV substation		JCPL (100%)
b0279.11	Install 6.6 MVAR capacitor at Newburg Q Bus 34.5 kV substation		JCPL (100%)
b0286	Install 130 MVAR capacitor at Whippany 230 kV		JCPL (100%)
b0289	Install 600 MVAR Dynamic Reactive Device in the Whippany 230 kV vicinity		AEC (0.65%) / JCPL (30.37%) / Neptune* (4.96%) / PSEG (59.65%) / RE (2.66%) / ECP** (1.71%)
b0289.1	Install additional 130 MVAR capacitor at West Wharton 230 kV substation		JCPL (100%)

* Neptune Regional Transmission System, LLC

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0292	Replace a 1600A line trap at Atlantic Larrabee 230 kV substation		JCPL (100%)
b0350	Implement Operating Procedure of closing the Glendon – Gilbert 115 kV circuit		JCPL (100%)
b0356	Replace wave trap on the Portland – Greystone 230 kV		JCPL (100%)
b0361	Change tap of limiting CT at Morristown 230 kV		JCPL (100%)
b0362	Change tap setting of limiting CT at Pohatcong 230 kV		JCPL (100%)
b0363	Change tap setting of limiting CT at Windsor 230 kV		JCPL (100%)
b0364	Change tap setting of CT at Cookstown 230 kV		JCPL (100%)
b0423.1	Upgrade terminal equipment at Readington (substation conductor)		JCPL (100%)
b0520	Replace Gilbert circuit breaker 12A		JCPL (100%)
b0657	Construct Boston Road 34.5 kV stations, construct Hyson 34.5 stations, add a 7.2 MVAR capacitor at Boston Road 34.5 kV		JCPL (100%)
b0726	Add a 2nd Raritan River 230/115 kV transformer	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $950,666 2018: $846,872 2019: $827,854	AEC (2.45%) / JCPL (97.55%)
b1020	Replace wave trap at Englishtown on the Englishtown - Manalapan circuit		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1075	Replace the West Wharton - Franklin - Vermont D931 and J932 115 kV line conductors with 1590 45/7 ACSR wire between the tower structures 78 and 78-B		JCPL (100%)
b1154.1	Upgrade the Whippany 230 kV breaker 'JB'		JCPL (100%)
b1155.1	Upgrade the Red Oak 230 kV breaker 'G1047'		JCPL (100%)
b1155.2	Upgrade the Red Oak 230 kV breaker 'T1034'		JCPL (100%)
b1345	Install Martinsville 4-breaker 34.5 rink bus		JCPL (100%)
b1346	Reconductor the Franklin – Humburg (R746) 4.7 miles 34.5 kV line with 556 ACSR and build 2.7 miles 55 ACSR line extension to Sussex		JCPL (100%)
b1347	Replace 500 CU substation conductor with 795 ACSR on the Whitesville – Asbury Tap 34.5 kV (U47) line		JCPL (100%)
b1348	Upgrade the Newton – North Newton 34.5 kV (F708) line by adding a second underground 1250 CU egress cable		JCPL (100%)
b1349	Reconductor 5.2 miles of the Newton – Woodruffs Gap 34.5 kV (A703) line with 556 ACSR		JCPL (100%)
b1350	Upgrade the East Flemington – Flemington 34.5 kV (V724) line by adding second underground 1000 AL egress cable and replacing 4/0		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1351	Add 34.5 kV breaker on the Larrabee A and D bus tie		JCPL (100%)
b1352	Upgrade the Smithburg – Centerstate Tap 34.5 kV (X752) line by adding second 200 ft underground 1250 CU egress cable		JCPL (100%)
b1353	Upgrade the Larrabee – Laurelton 34.5 kV (Q43) line by adding second 700 ft underground 1250 CU egress cable		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1354	Add four 34.5 kV breakers and re-configure A/B bus at Rockaway		JCPL (100%)
b1355	Build a new section 3.3 miles 34.5 kV 556 ACSR line from Riverdale to Butler		JCPL (100%)
b1357	Build 10.2 miles new 34.5 kV line from Larrabee – Howell		JCPL (100%)
b1359	Install a Troy Hills 34.5 kV by-pass switch and reconfigure the Montville – Whippany 34.5 kV (D4) line		JCPL (100%)
b1360	Reconductor 0.7 miles of the Englishtown – Freehold Tap 34.5 kV (L12) line with 556 ACSR		JCPL (100%)
b1361	Reconductor the Oceanview – Neptune Tap 34.5 kV (D130) line with 795 ACSR		JCPL (100%)
b1362	Install a 23.8 MVAR capacitor at Wood Street 69 kV		JCPL (100%)
b1364	Upgrade South Lebanon 230/69 kV transformer #1 by replacing 69 kV substation conductor with 1590 ACSR		JCPL (100%)
b1399.1	Upgrade the Whippany 230 kV breaker ‘QJ’		JCPL (100%)
b1673	Rocktown - Install a 230/34.5 kV transformer by looping the Pleasant Valley - E Flemington 230 kV Q-2243 line (0.4 miles) through the Rocktown Substation		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1674	Build a new Englishtown - Wyckoff St 15 mile, 115 kV line and install 115/34.5 kV transformer at Wyckoff St		JCPL (100%)
b1689	Atlantic Sub - 230 kV ring bus reconfiguration. Put a “source” between the Red Bank and Oceanview “loads”		JCPL (100%)
b1690	Build a new third 230 kV line into the Red Bank 230 kV substation		JCPL (100%)
b1853	Install new 135 MVA 230/34.5 kV transformer with one 230 kV CB at Eaton Crest and create a new 34.5 kV CB straight bus to feed new radial lines to Locust Groove and Interdata/Woodbine		JCPL (100%)
b1854	Readington I737 34.5 kV Line - Parallel existing 1250 CU UG cable (440 feet)		JCPL (100%)
b1855	Oceanview Substation - Relocate the H216 breaker from the A bus to the B bus		JCPL (100%)
b1856	Madison Tp to Madison (N14) line - Upgrade limiting 250 Cu substation conductor with 795 ACSR at Madison sub		JCPL (100%)
b1857	Montville substation - Replace both the 397 ACSR and the 500 Cu substation conductor with 795 ACSR on the 34.5 kV (M117) line		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1858	Reconductor the Newton - Mohawk (Z702) 34.5 kV line with 1.9 miles of 397 ACSR		JCPL (100%)
b2003	Construct a Whippany to Montville 230 kV line (6.4 miles)		JCPL (100%)
b2015	Build a new 230 kV circuit from Larrabee to Oceanview	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $9,616,241 2018: $18,839,128 2019: $19,935,489	JCPL (35.83%) / NEPTUNE* (23.61%) / HTP (1.77%) / ECP** (1.49%) / PSEG (35.87%) / RE (1.43%)
b2147	At Deep Run, install 115 kV line breakers on the B2 and C3 115 kV lines		JCPL (100%)

* Neptune Regional Transmission System, LLC

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

EXHIBIT 2

Pro Forma Settlement Tariff Sheets
JCP&L's PJM Tariff Attachments H-4, H-4A, and H-4B, and Schedule 12-Appendix
(Marked / Redline Format)

ATTACHMENT H-4

Annual Transmission Rates -- Jersey Central Power & Light Company for Network Integration Transmission Service

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1. The annual transmission revenue requirement ~~and the rate~~ for Network Integration Transmission Service is $135,000,000. Attachment H-4A sets forth the rates for deliveries that utilize Jersey Central Power & Light Company (“JCP&L”) distribution facilities at voltages below 34.5 kV delta~~are equal to the results of the formula shown in Attachment H- 4A, and will be posted on the PJM website pursuant to Attachment H-4B (Formula Rate Protocols)~~. The transmission revenue requirement ~~and the rate~~ reflects the cost of providing transmission service over the 34.5 kV delta and higher transmission facilities of ~~Jersey Central Power & Light Company (“~~JCP&L~~”)~~. ~~Service utilizing facilities at voltages below 34.5 kV delta will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.~~

~~2. The formula rate set forth in Attachment H-4A shall be calculated on the basis of projections, subject to true-up to actual data in accordance with the adjustment mechanism described in Attachment H-4B (Formula Rate Protocols).~~

~~3~~2. The ~~rate and~~ revenue requirements in this attachment shall be effective until amended by JCP&L or modified by the Commission.

~~4~~3. In addition to the ~~rate~~revenue requirement set forth in paragraph 1 above, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse JCP&L for applicable sales, excise, “Btu,” carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT H-4A
Other Supporting Facilities -- Jersey Central Power & Light Company

As provided in Attachment H-4, section 1, service utilizing facilities at voltages below 34.5 kV delta to serve certain New Jersey municipal utilities will be provided at rates determined on a case-by-case basis and stated in existing NITS Agreements under Attachment F through the expiration of such agreements on May 31, 2019. Commencing on June 1, 2019, the rates for such service shall be as follows:

Borough of Butler, New Jersey: $0.1121/kW-Month

Borough of Lavallette, New Jersey: $2.3784/kW-Month

Borough of Madison, New Jersey: $0.0570/kW-Month

Borough of Pemberton, New Jersey: $1.1081/kW-Month

Borough of Seaside Heights, New Jersey: $1.2459/kW-Month

The above rates will be applied to the each of the New Jersey boroughs' monthly sixty (60) minute coincident billing demands measured at the time of JCP&L's system peak each month.

Attachment 13
~~Attachment H-4A~~
~~page 1 of 5~~

~~Formula Rate - Non-Levelized~~ ~~For the 12 months ended 12/31/2017~~

~~Rate Formula Template~~
~~Utilizing FERC Form 1 Data~~

~~Jersey Central Power & Light~~

~~Line No.~~						~~Allocated Amount~~
~~1~~	~~GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]~~					
	~~REVENUE CREDITS~~	~~(Note T)~~	~~Total~~	~~Allocator~~		
~~2~~	~~Account No. 451~~	~~(page 4, line 29)~~		~~TP~~	~~1.00000~~	
~~3~~	~~Account No. 454~~	~~(page 4, line 30)~~		~~TP~~	~~1.00000~~	
~~4~~	~~Account No. 456~~	~~(page 4, line 31)~~		~~TP~~	~~1.00000~~	
~~5~~	~~Revenues from Grandfathered Interzonal Transactions~~			~~TP~~	~~1.00000~~	
~~6~~	~~Revenues from service provided by the ISO at a discount~~			~~TP~~	~~1.00000~~	
~~7~~	~~TEC Revenue~~	~~Attachment 11, Page 2, Line 3, Col. 12~~		~~TP~~	~~1.00000~~	
~~8~~	~~TOTAL REVENUE CREDITS (sum lines 2-7)~~					
~~9~~	~~True-up Adjustment with Interest~~	~~Attachment 13, Line 28~~				
~~10~~	~~NET REVENUE REQUIREMENT~~	~~(Line 1 - Line 8 + Line 9)~~				
	~~DIVISOR~~					~~Total~~
~~11~~	~~1 Coincident Peak (CP) (MW)~~				~~(Note A)~~	
~~12~~	~~Average 12 CPs (MW)~~				~~(Note CC)~~	
			~~Total~~			
~~13~~	~~Annual Rate ($/MW/Yr)~~	~~(line 10 / line 11)~~				
			~~Peak Rate Total~~			~~Off-Peak Rate Total~~
~~14~~	~~Point-to-Point Rate ($/MW/Year)~~	~~(line 10 / line 12)~~				
~~15~~	~~Point-to-Point Rate ($/MW/Month)~~	~~(line 14/12)~~				
~~16~~	~~Point-to-Point Rate ($/MW/Week)~~	~~(line 14/52)~~				
~~17~~	~~Point-to-Point Rate ($/MW/Day)~~	~~(line 16/5; line 16/7)~~				
~~18~~	~~Point-to-Point Rate ($/MWh)~~	~~(line 14/4,160; line 14/8,760)~~				

~~Formula Rate - Non-Levelized~~ ~~Rate Formula Template~~ ~~For the 12 months ended 12/31/2017~~

~~Utilizing FERC Form 1 Data~~

~~Jersey Central Power & Light~~

	~~(1)~~	~~(2)~~	~~(3)~~	~~(4)~~		~~(5)~~
~~Line No.~~	**~~RATE BASE:~~**	**~~Source~~**	**~~Company Total~~**	**~~Allocator~~**		**~~Transmission~~** ~~(Col 3 times Col 4)~~
	~~GROSS PLANT IN SERVICE~~					
~~1~~	~~Production~~	~~Attachment 3, Line 14, Col. 1 (Notes U & X)~~		~~NA~~		
~~2~~	~~Transmission~~	~~Attachment 3, Line 14, Col. 2 (Notes U & X)~~		~~TP~~	~~1.00000~~	
~~3~~	~~Distribution~~	~~Attachment 3, Line 14, Col. 3 (Notes U & X)~~		~~NA~~		
~~4~~	~~General & Intangible~~	~~Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)~~		~~GP~~	~~1.00000~~	
~~5~~	~~Common~~	~~Attachment 3, Line 14, Col. 6 (Notes U & X)~~		~~CE~~	~~1.00000~~	
~~6~~	~~TOTAL GROSS PLANT (sum lines 1-5)~~			~~GP=~~	~~100.00%~~	
	~~ACCUMULATED DEPRECIATION~~					
~~7~~	~~Production~~	~~Attachment 4, Line 14, Col. 1 (Notes U & X)~~		~~NA~~		
~~8~~	~~Transmission~~	~~Attachment 4, Line 14, Col. 2 (Notes U & X)~~		~~TP~~	~~1.00000~~	
~~9~~	~~Distribution~~	~~Attachment 4, Line 14, Col. 3 (Notes U & X)~~		~~NA~~		
~~10~~	~~General & Intangible~~	~~Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)~~		~~GP~~	~~1.00000~~	
~~11~~	~~Common~~	~~Attachment 4, Line 14, Col. 6 (Notes U & X)~~		~~CE~~	~~1.00000~~	
~~12~~	~~TOTAL ACCUM. DEPRECIATION (sum lines 7-11)~~					
	~~NET PLANT IN SERVICE~~					
~~13~~	~~Production~~	~~(line 1- line 7)~~				
~~14~~	~~Transmission~~	~~(line 2- line 8)~~		-		
~~15~~	~~Distribution~~	~~(line 3 - line 9)~~				
~~16~~	~~General & Intangible~~	~~(line 4 - line 10)~~				
~~17~~	~~Common~~	~~(line 5 - line 11)~~				
~~18~~	~~TOTAL NET PLANT (sum lines 13-17)~~			~~NP=~~	~~100.00%~~	
	~~ADJUSTMENTS TO RATE BASE~~					
~~19~~	~~Account No. 281 (enter negative)~~	~~Attachment 5, Line 3, Col. 1 (Notes C, F, Y)~~		~~NA~~		
~~20~~	~~Account No. 282 (enter negative)~~	~~Attachment 5, Line 3, Col. 2 (Note C, F, Y)~~		~~DA~~	~~1.00000~~	
~~21~~	~~Account No. 283 (enter negative)~~	~~Attachment 5, Line 3, Col. 3 (Notes C, F, Y)~~		~~DA~~	~~1.00000~~	
~~22~~	~~Account No. 190~~	~~Attachment 5, Line 3, Col. 4 (Notes C, F, Y)~~		~~DA~~	~~1.00000~~	
~~23~~	~~Account No. 255 (enter negative)~~	~~Attachment 5, Line 3, Col. 5 (Notes C, F, Y)~~		~~DA~~	~~1.00000~~	
~~24~~	~~Unfunded Reserve Plant-related (enter negative)~~	~~Attachment 14, Line 6, Col. 6 (Notes C & Y)~~		~~DA~~	~~1.00000~~	
~~25~~	~~Unfunded Reserve Labor-related (enter negative)~~	~~Attachment 14, Line 9, Col. 6 (Notes C & Y)~~		~~DA~~	~~1.00000~~	
~~26~~	~~CWIP~~	~~216.b (Notes X & Z)~~		~~DA~~	~~1.00000~~	
~~27~~	~~Unamortized Regulatory Asset~~	~~Attachment 16a, 16b, 16c, Line 15, Col. 7 (Note X)~~		~~DA~~	~~1.00000~~	
~~28~~	~~Unamortized Abandoned Plant~~	~~Attachment 17, Line 15, Col. 7 (Notes X & BB)~~		~~DA~~	~~1.00000~~	
~~29~~	~~TOTAL ADJUSTMENTS (sum lines 19-28)~~					
~~30~~	~~LAND HELD FOR FUTURE USE~~	~~214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)~~		~~TP~~	~~1.00000~~	
~~31~~	~~WORKING CAPITAL (Note H)~~					
~~32~~	~~CWC~~	~~1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)~~				
~~33~~	~~Materials & Supplies (Note G)~~	~~227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)~~		~~TE~~	~~1.00000~~	
~~34~~	~~Prepayments (Account 165)~~	~~111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)~~		~~GP~~	~~1.00000~~	
~~35~~	~~TOTAL WORKING CAPITAL (sum lines 32 - 34)~~					
~~36~~	~~RATE BASE (sum lines 18, 29, 30, & 35)~~					

Attachment 13

~~Attachment H-4A~~

~~page 3 of 5~~

~~Formula Rate - Non-Levelized~~ ~~Rate Formula Template~~ ~~For the 12 months ended 12/31/2017~~

~~Utilizing FERC Form 1 Data~~

~~Jersey Central Power & Light~~

~~Line No.~~	~~(1)~~ ~~RATE BASE:~~	~~(2)~~ ~~Source~~	~~(3)~~ ~~Company Total~~	~~(4)~~ ~~Allocator~~		~~(5)~~ ~~Transmission~~ ~~(Col 3 times Col 4)~~
	~~O&M~~					
~~1~~	~~Transmission~~	~~321.112.b~~		~~TE~~	~~1.00000~~	
~~2~~	~~Less LSE Expenses Included in Transmission O&M Accounts (Note W)~~			~~DA~~	~~1.00000~~	
~~3~~	~~Less Account 565~~	~~321.96.b~~		~~DA~~	~~1.00000~~	
~~4~~	~~Less Account 566~~	~~321.97.b~~		~~DA~~	~~1.00000~~	
~~5~~	~~A&G~~	~~323.197.b~~		~~W/S~~	~~1.00000~~	
~~6~~	~~Less FERC Annual Fees~~			~~W/S~~	~~1.00000~~	
~~7~~	~~Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)~~			~~W/S~~	~~1.00000~~	
~~8~~	~~Plus Transmission Related Reg. Comm. Exp. (Note I)~~			~~TE~~	~~1.00000~~	
~~9~~	~~PBOP Expense Adjustment in Year~~	~~Attachment 6, Line 9 (Note C)~~		~~DA~~	~~1.00000~~	
~~10~~	~~Common~~	~~356.1~~		~~CE~~	~~1.00000~~	
~~11~~	~~Account 407.3 Amortization of Regulatory Assets~~	~~Attachment 16a, 16b, 16c, Line 15, Col. 5~~		~~DA~~	~~1.00000~~	
~~12~~	~~Account 566 Amortization of Regulatory Assets~~			~~DA~~	~~1.00000~~	
~~13~~	~~Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset) 321.97.b - line 12~~			~~DA~~	~~1.00000~~	
~~14~~	~~Total Account 566 (sum lines 12 & 13, ties to 321.97.b)~~					
~~15~~	~~TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)~~					
	~~DEPRECIATION AND AMORTIZATION EXPENSE~~					
~~16~~	~~Transmission~~	~~336.7.b (Note U)~~		~~TP~~	~~1.00000~~	
~~17~~	~~General & Intangible~~	~~336.1.f & 336.10.f (Note U)~~		~~GP~~	~~1.00000~~	
~~18~~	~~Common~~	~~336.11.b (Note U)~~		~~CE~~	~~1.00000~~	
~~19~~	~~Amortization of Abandoned Plant~~	~~Attachment 17, Line 15, Col. 5 (Note BB)~~		~~DA~~	~~1.00000~~	
~~20~~	~~TOTAL DEPRECIATION (sum lines 16 -19)~~					
	~~TAXES OTHER THAN INCOME TAXES (Note J)~~					
	~~LABOR RELATED~~					
~~21~~	~~Payroll~~	~~263.i (Attachment 7, line 1z)~~		~~W/S~~	~~1.00000~~	
~~22~~	~~Highway and vehicle~~	~~263.i (Attachment 7, line 2z)~~		~~W/S~~	~~1.00000~~	
~~23~~	~~PLANT RELATED~~					
~~24~~	~~Property~~	~~263.i (Attachment 7, line 3z)~~		~~GP~~	~~1.00000~~	
~~25~~	~~Gross Receipts~~	~~263.i (Attachment 7, line 4z)~~		~~NA~~		
~~26~~	~~Other~~	~~263.i (Attachment 7, line 5z)~~		~~GP~~	~~1.00000~~	
~~27~~	~~Payments in lieu of taxes~~	~~Attachment 7, line 6z~~		~~GP~~	~~1.00000~~	
~~28~~	~~TOTAL OTHER TAXES (sum lines 21 - 27)~~					
	~~INCOME TAXES~~	~~(Note K)~~				
~~29~~	~~T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =~~					
~~30~~	~~CIT=(T/1-T) * (1-(WCLTD/R)) =~~					
	~~where WCLTD=(page 4, line 22) and R= (page 4, line 25)~~					
	~~and FIT, SIT & p are as given in footnote K.~~					
~~31~~	~~1 / (1 - T) = (from line 30)~~					
~~32~~	~~Amortized Investment Tax Credit (266.8.f) (enter negative)~~					
~~33~~	~~Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]~~					
~~34~~	~~(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]~~					
~~35~~	~~Income Tax Calculation = line 30 * line 40~~			~~NA~~		
~~36~~	~~ITC adjustment (line 31 * line 32)~~			~~NP~~	~~1.00000~~	
~~37~~	~~Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)~~			~~DA~~	~~1.00000~~	
~~38~~	~~(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)~~			~~DA~~	~~1.00000~~	
~~39~~	~~Total Income Taxes~~	~~sum lines 35 through 38~~				
~~40~~	~~RETURN~~ ~~[Rate Base (page 2, line 36) * Rate of Return (page 4, line 25, col. 6)]~~			~~NA~~		
~~41~~	~~GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)~~ ~~(sum lines 15, 20, 28, 39, 40)~~					
~~42~~	~~ADDITIONAL INCENTIVE REVENUE~~	~~Attachment 11, Line 4 (Note AA)~~				
~~43~~	~~GROSS REV. REQUIREMENT~~ ~~(line 41 + line 42)~~					

Attachment 13

~~Attachment H-4A~~

~~page 4 of 5~~

~~Formula Rate - Non-Levelized~~

~~Rate Formula Template~~

~~Utilizing FERC Form 1 Data~~

~~For the 12 months ended 12/31/2017~~

~~Jersey Central Power & Light~~

~~SUPPORTING CALCULATIONS AND NOTES~~

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

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

~~Jersey Central Power & Light~~

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

~~Note~~
~~Letter~~

~~A~~ ~~As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.~~

~~B~~ ~~Prepayments shall exclude prepayments of income taxes.~~

~~C~~ ~~Transmission-related only~~

~~D~~ ~~Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction~~

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

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

~~G~~ ~~Identified in Form 1 as being only transmission related.~~

~~H~~ ~~Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.~~

~~I~~ ~~Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.~~

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

~~K~~ ~~The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 31).~~

~~Inputs Required:~~	~~FIT =~~		
	~~SIT=~~		~~(State Income Tax Rate or Composite SIT)~~
	~~p =~~		~~(percent of federal income tax deductible for state purposes)~~

~~L~~ ~~Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA.~~

~~M~~ ~~Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test.~~

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

~~O~~ ~~Enter dollar amounts~~

~~P~~ ~~Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.~~

~~Q~~ ~~Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.~~

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

~~S~~ ~~Excludes revenues unrelated to transmission services.~~

~~T~~ ~~The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by it own reference.~~

~~U~~ ~~Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.~~

~~V~~ ~~On Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.~~

~~W~~ ~~Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.~~

~~X~~ ~~Calculate using a 13 month average balance.~~

~~Y~~ ~~Calculate using average of beginning and end of year balance.~~

~~Z~~ ~~Includes only CWIP authorized by the Commission for inclusion in rate base.~~

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

~~BB~~ ~~Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.~~

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

Attachment 13

~~Attachment H-4A, Attachment 1~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Schedule 1A Rate Calculation~~

~~1~~	~~$~~		~~Attachment H-4A, Page 4, Line 7~~
~~2~~	~~$~~		~~Revenue Credits for Sched 1A - Note A~~
~~3~~	~~$~~		~~Net Schedule 1A Expenses (Line 1 - Line 2)~~
~~4~~			~~Annual MWh in JCP&L Zone - Note B~~
~~5~~	~~$~~		~~Schedule 1A rate $/MWh (Line 3/ Line 4)~~

~~Note:~~

~~A~~ ~~Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of JCP&L's zone during the year used to calculate rates under Attachment H-4A.~~

~~B~~ ~~Load expressed in MWh consistent with load used for billing under Schedule 1A for the JCP&L zone. Data from RTO settlement systems for the calendar year prior to the rate year.~~

Attachment 13

~~Attachment H-4A, Attachment 2~~

~~page 1 of 1~~

~~For the 12 months ended 12/31/2017~~

~~Incentive ROE Calculation~~

~~Return Calculation~~

			~~Source Reference~~
~~1~~	~~Rate Base~~		~~Attachment H-4A, page 2, Line 36, Col. 5~~
~~2~~	~~Preferred Dividends~~	~~enter positive~~	~~Attachment H-4A, page 4, Line 21, Col. 6~~
	~~Common Stock~~		
~~3~~	~~Proprietary Capital~~		~~Attachment 8, Line 14, Col. 1~~
~~4~~	~~Less Preferred Stock~~		~~Attachment 8, Line 14, Col. 2~~
~~5~~	~~Less Accumulated Other Comprehensive Income Account 219~~		~~Attachment 8, Line 14, Col. 4~~
~~6~~	~~Less Account 216.1 & Goodwill~~		~~Attachment 8, Line 14, Col. 3&5~~
~~7~~	~~Common Stock~~		~~Attachment 8, Line 14, Col. 6~~
	~~Capitalization~~		
~~8~~	~~Long Term Debt~~		~~Attachment H-4A, page 4, Line 22, Col. 3~~
~~9~~	~~Preferred Stock~~		~~Attachment H-4A, page 4, Line 23, Col. 3~~
~~10~~	~~Common Stock~~		~~Attachment H-4A, page 4, Line 24, Col. 3~~
~~11~~	~~Total Capitalization~~		~~Attachment H-4A, page 4, Line 25, Col. 3~~
~~12~~	~~Debt %~~	~~Total Long Term Debt~~	~~Attachment H-4A, page 4, Line 22, Col. 4~~
~~13~~	~~Preferred %~~	~~Preferred Stock~~	~~Attachment H-4A, page 4, Line 23, Col. 4~~
~~14~~	~~Common %~~	~~Common Stock~~	~~Attachment H-4A, page 4, Line 24, Col. 4~~
~~15~~	~~Debt Cost~~	~~Total Long Term Debt~~	~~Attachment H-4A, page 4, Line 22, Col. 5~~
~~16~~	~~Preferred Cost~~	~~Preferred Stock~~	~~Attachment H-4A, page 4, Line 23, Col. 5~~
~~17~~	~~Common Cost~~	~~Common Stock~~	
~~18~~	~~Weighted Cost of Debt~~	~~Total Long Term Debt (WCLTD)~~	~~(Line 12*Line 15)~~
~~19~~	~~Weighted Cost of Preferred~~	~~Preferred Stock~~	~~(Line 13*Line 16)~~
~~20~~	~~Weighted Cost of Common~~	~~Common Stock~~	~~(Line 14*Line 17)~~
~~21~~	~~Rate of Return on Rate Base (ROR)~~		~~(Sum Lines 18 to 20)~~
~~22~~	~~Investment Return = Rate Base * Rate of Return~~		**~~(Line 1*Line 21)~~**

~~Income Tax Rates~~

~~23~~	~~T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =~~		~~Attachment H-4A, page 3, Line 29, Col. 3~~
~~24~~	~~CIT=(T/1-T) * (1-(WCLTD/R)) =~~		~~Calculated~~
~~25~~	~~1 / (1 - T) = (from line 23)~~		~~Calculated~~
~~26~~	~~Amortized Investment Tax Credit (266.8.f) (enter negative)~~		~~Attachment H-4A, page 3, Line 32, Col. 3~~
~~27~~	~~Tax Effect of Permanent Differences and AFUDC Equity~~		~~Attachment H-4A, page 3, Line 33, Col. 3~~
~~28~~	~~(Excess)/Deficient Deferred Income Taxes~~		~~Attachment H-4A, page 3, Line 34, Col. 3~~
~~29~~	~~Income Tax Calculation~~		~~(Line 22*Line 24)~~
~~30~~	~~ITC adjustment~~		~~Attachment H-4A, page 3, Line 36, Col. 5~~
~~31~~	~~Permanent Differences and AFUDC Equity Tax Adjustment~~		~~Attachment H-4A, page 3, Line 37, Col. 5~~
~~32~~	~~(Excess)/Deficient Deferred Income Tax Adjustment~~		~~Attachment H-4A, page 3, Line 38, Col. 5~~
~~33~~	~~Total Income Taxes~~		~~Sum Lines 29 to 32~~

~~34~~	~~Return and Income taxes with increase in ROE~~		~~(Line 22 + Line 33)~~
~~35~~	~~Return without incentive adder~~		~~Attachment H-4A, Page 3, Line 40, Col. 5~~
~~36~~	~~Income Tax without incentive adder~~		~~Attachment H-4A, Page 3, Line 39, Col. 5~~
~~37~~	~~Return and Income taxes without increase in ROE~~		~~Line 35 + Line 36~~
~~38~~	~~Return and Income taxes with increase in ROE~~		~~Line 34~~
~~39~~	~~Incremental Return and incomes taxes for increase in ROE~~		~~Line 38 - Line 37~~
~~40~~	~~Rate Base~~		~~Line 1~~
~~41~~	~~Incremental Return and incomes taxes for increase in ROE divided by rate base~~		~~Line 39 / Line 40~~

~~Notes:~~

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

~~Attachment H-4A, Attachment 3~~
~~page 1 of 1~~

~~Gross Plant Calculation~~

~~For the 12 months ended 12/31/2017~~

			~~[1]~~ ~~Production~~	~~[2]~~ ~~Transmission~~	~~[3]~~ ~~Distribution~~	~~[4]~~ ~~Intangible~~	~~[5]~~ ~~General~~	~~[6]~~ ~~Common~~	~~[7]~~ ~~Total~~
~~1~~	~~December~~	~~2016~~							
~~2~~	~~January~~	~~2017~~							
~~3~~	~~February~~	~~2017~~							
~~4~~	~~March~~	~~2017~~							
~~5~~	~~April~~	~~2017~~							
~~6~~	~~May~~	~~2017~~							
~~7~~	~~June~~	~~2017~~							
~~8~~	~~July~~	~~2017~~							
~~9~~	~~August~~	~~2017~~							
~~10~~	~~September~~	~~2017~~							
~~11~~	~~October~~	~~2017~~							
~~12~~	~~November~~	~~2017~~							
~~13~~	~~December~~	~~2017~~							
~~14~~	**~~13-month Average [A] [C]~~**								

			~~Production~~	~~Transmission~~	~~Distribution~~	~~Intangible~~	~~General~~	~~Common~~	~~Total~~
		~~[B]~~	~~205.46.g~~	~~207.58.g~~	~~207.75.g~~	~~205.5.g~~	~~207.99.g~~	~~356.1~~	
~~15~~	~~December~~	~~2016~~							
~~16~~	~~January~~	~~2017~~							
~~17~~	~~February~~	~~2017~~							
~~18~~	~~March~~	~~2017~~							
~~19~~	~~April~~	~~2017~~							
~~20~~	~~May~~	~~2017~~							
~~21~~	~~June~~	~~2017~~							
~~22~~	~~July~~	~~2017~~							
~~23~~	~~August~~	~~2017~~							
~~24~~	~~September~~	~~2017~~							
~~25~~	~~October~~	~~2017~~							
~~26~~	~~November~~	~~2017~~							
~~27~~	~~December~~	~~2017~~							
~~28~~	~~13-month Average~~								

~~Asset Retirement Costs~~

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

~~Notes:~~
~~[A] Taken to Attachment H-4A, page 2, lines 1-6, Col. 3~~
~~[B] Reference for December balances as would be reported in FERC Form 1.~~
~~[C] Balance excludes Asset Retirements Costs~~

~~Attachment H-4A, Attachment 4~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Accumulated Depreciation Calculation~~

			~~[1]~~ ~~Production~~	~~[2]~~ ~~Transmission~~	~~[3]~~ ~~Distribution~~	~~[4]~~ ~~Intangible~~	~~[5]~~ ~~General~~	~~[6]~~ ~~Common~~	~~[7]~~ ~~Total~~
~~1~~	~~December~~	~~2016~~							
~~2~~	~~January~~	~~2017~~							
~~3~~	~~February~~	~~2017~~							
~~4~~	~~March~~	~~2017~~							
~~5~~	~~April~~	~~2017~~							
~~6~~	~~May~~	~~2017~~							
~~7~~	~~June~~	~~2017~~							
~~8~~	~~July~~	~~2017~~							
~~9~~	~~August~~	~~2017~~							
~~10~~	~~September~~	~~2017~~							
~~11~~	~~October~~	~~2017~~							
~~12~~	~~November~~	~~2017~~							
~~13~~	~~December~~	~~2017~~							
~~14~~	~~13-month Average~~	~~[A] [C]~~							

				~~Production~~	~~Transmission~~	~~Distribution~~	~~Intangible~~	~~General~~	~~Common~~	~~Total~~
			~~[B]~~							
~~15~~	~~December~~	~~2016~~								
~~16~~	~~January~~	~~2017~~								
~~17~~	~~February~~	~~2017~~								
~~18~~	~~March~~	~~2017~~								
~~19~~	~~April~~	~~2017~~								
~~20~~	~~May~~	~~2017~~								
~~21~~	~~June~~	~~2017~~								
~~22~~	~~July~~	~~2017~~								
~~23~~	~~August~~	~~2017~~								
~~24~~	~~September~~	~~2017~~								
~~25~~	~~October~~	~~2017~~								
~~26~~	~~November~~	~~2017~~								
~~27~~	~~December~~	~~2017~~								
~~28~~	~~13-month Average~~									

~~Reserve for Depreciation of Asset Retirement Costs~~

				~~Production~~	~~Transmission~~	~~Distribution~~	~~Intangible~~	~~General~~	~~Common~~
			~~[B]~~		~~Company Records~~				
~~29~~	~~December~~	~~2016~~							
~~30~~	~~January~~	~~2017~~							
~~31~~	~~February~~	~~2017~~							
~~32~~	~~March~~	~~2017~~							
~~33~~	~~April~~	~~2017~~							
~~34~~	~~May~~	~~2017~~							
~~35~~	~~June~~	~~2017~~							
~~36~~	~~July~~	~~2017~~							
~~37~~	~~August~~	~~2017~~							
~~38~~	~~September~~	~~2017~~							
~~39~~	~~October~~	~~2017~~							
~~40~~	~~November~~	~~2017~~							
~~41~~	~~December~~	~~2017~~							
~~42~~	~~13-month Average~~			~~-~~		~~-~~	~~-~~	~~-~~	~~-~~

~~Notes:~~

~~[A]~~	~~Taken to Attachment H-4A, page 2, lines 7-11, Col. 3~~
~~[B]~~	~~Reference for December balances as would be reported in FERC Form 1.~~
~~[C]~~	~~Balance excludes reserve for depreciation of asset retirement costs~~

Attachment 13

~~Attachment H-4A, Attachment 5~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

				~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~
				~~ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below)~~					
				~~Acct. No. 281~~ **~~(enter negative)~~**	**~~Acct. No. 282~~** **~~(enter negative)~~** ~~[B]~~	**~~Acct. No. 283~~** **~~(enter negative)~~** ~~[C]~~	**~~Acct. No. 190~~** ~~[D]~~	**~~Acct. No. 255~~** **~~(enter negative)~~** ~~[E]~~	**~~Total~~**
~~1~~	~~December 31~~	~~2016~~		-					
~~2~~	~~December 31~~	~~2017~~		-					
~~3~~	**~~Begin/End Average~~**		~~[A]~~	-					
				~~ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjustments from notes below)~~					
				~~Acct. No. 281~~	**~~Acct. No. 282~~**	**~~Acct. No. 283~~**	**~~Acct. No. 190~~**	**~~Acct. No. 255~~**	**~~Total~~**
~~4~~	~~December 31~~	~~2016~~	~~[H]~~	-					
~~5~~	~~December 31~~	~~2017~~	~~[H]~~	-					
~~6~~	~~Begin/End Average~~			-					

~~Notes:~~

~~[A] Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-4A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively~~

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

	~~FAS 143 – ARO~~	~~FAS 106~~	~~FAS 109~~	~~CIAC~~	~~Normalization [G]~~
~~2016~~					
~~2017~~					
~~Begin/End Average~~					

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

	~~FAS 143 – ARO~~	~~FAS 106~~	~~FAS 109~~	~~CIAC~~	~~Normalization [G]~~
~~2016~~					
~~2017~~					
~~Begin/End Average~~					

~~[D] FERC Account No. 190 is adjusted for the following items.~~

	~~FAS 143 – ARO~~	~~FAS 106~~	~~FAS 109~~	~~CIAC~~	~~Normalization [G]~~
~~2016~~					
~~2017~~					
~~Begin/End Average~~					

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

~~[G] Sourced from Attachment 5b, page 2, col. 4~~

~~[H] Sourced from Attachment 5a, page 1, lines 1-5, col. 6 for beginning balance and page 1, lines 1-5, col. 7 for ending balance~~

Attachment 13
~~Attachment H-4A, Attachment 5a~~
~~page 1 of 6~~
~~For the 12 months ended 12/31/2017~~

~~Jersey Central Power & Light~~
~~Summary of Transmission ADIT (prior to adjusted items)~~

~~Line~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5~~	~~6~~	~~7~~
		~~Transmission Beginning~~	**~~Transmission Ending~~**	**~~Beg Plant & Labor Related Allocated to Transmission~~**	**~~End Plant & Labor Related Allocated to Transmission~~**	**~~Total Transmission Beginning~~**	**~~Total Transmission Ending~~**
		~~(Note F)~~	~~(Note F)~~	~~(page 1, col. K)~~	~~(page 1, col. L)~~	~~(col. 2 + col. 4) (Note E)~~	~~(col. 3 + col. 5) (Note E)~~
~~1~~	**~~ADIT- 282 From Account Subtotal Below~~**						
~~2~~	**~~ADIT-283 From Account Subtotal Below~~**						
~~3~~	**~~ADIT-190 From Account Subtotal Below~~**						
~~4~~	**~~ADIT-281 From Account Subtotal Below~~**						
~~5~~	**~~ADIT-255 From Account Subtotal Below~~**						
	~~Total (sum rows 1-5)~~						

~~Jersey Central Power & Light~~
~~Calculation of Plant & Labor Related ADIT allocated to Transmission~~

~~Line~~		~~F1~~	~~F2~~	~~G1~~	~~G2~~	~~H~~	~~I~~	~~J~~	~~K~~	~~L~~	~~M~~
		~~Beg Plant Related~~	**~~End Plant Related~~**	**~~Beg Labor Related~~**	**~~End Labor Related~~**	**~~Plant & Labor Subtotal~~**	**~~Gross Plant Allocator~~**	**~~Wages & Salary Allocator~~**	**~~Beg Plant & Labor Related ADIT~~**	**~~End Plant & Labor Related ADIT~~**	**~~Beg/End Avg Plant & Labor Total~~**
		~~(Note A)~~	~~(Note A)~~	~~(Note B)~~	~~(Note B)~~	~~Col. F1 + Col. F2 + Col. G1 + Col. G2~~	~~(Note C)~~	~~(Note D)~~	~~(Col. F1 * Col. I) + (Col. F2 * Col. J)~~	~~(Col. F2 * Col. I) + (Col. G2 * Col. J)~~	~~(Col. K + Col. L) / 2~~
~~1~~	**~~ADIT- 282 From Account Total Below~~**										
~~2~~	**~~ADIT-283 From Account Total Below~~**										
~~3~~	**~~ADIT-190 From Account Total Below~~**										
~~4~~	**~~ADIT-281 From Account Total Below~~**										
~~5~~	**~~ADIT-255 From Account Total Below~~**										
~~6~~	**~~Subtotal~~**										

~~Notes~~

~~A~~	~~From column F (beginning on page 2)~~
~~B~~	~~From column G (beginning on page 2)~~
~~C~~	~~Refers to Attachment H-4A, page 2, line 6, col. 4~~
~~D~~	~~Refers to Attachment H-4A, page 4, line 16, col.6~~
~~E~~	~~Total Transmission Beginning taken to Attachment 5, line 4 and Total Transmission Ending taken to Attachment 5, line 5~~
~~F~~	~~From column E (beginning on page 2) by account~~

~~In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-F and each separate ADIT item will be listed, Dissimilar items with amounts exceeding $100,000 will be listed separately.~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT-190~~	~~Beg of Year Balance p234.18.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~							-	-	
~~ADIT-190~~		~~End of Year Balance p234.18.c~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~	-						-	-	

~~**Instructions for Account 190:**~~

~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. 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.~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT- 282~~	~~Beg of Year Balance p274.9.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
					-	-			
~~Subtotal~~							-	-	
~~ADIT- 282~~		~~End of Year Balance p275.9.k~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~							-	-	

~~Instructions for Account 282:~~
~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. 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.~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT-283~~	~~Beg of Year Balance~~ ~~p276.19.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
						-			
~~Subtotal~~							-	-	
~~ADIT-283~~		~~End of Year Balance~~ ~~p277.19.k~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
						-			
						-			
						-			
						-			
						-			
~~Subtotal~~	-						-	-	

~~Instructions for Account 283:~~

~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. 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.~~

~~PJM TRANSMISSION OWNER~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT-281~~	~~Beg of Year Balance~~ ~~p272.8.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
						-			
						-			
						-			
						-			
						-			
						-			
						-			
						-			
						-			
~~Subtotal~~	-				-	-	-	-	
~~ADIT-281~~		~~End of Year Balance~~ ~~p273.8.k~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
						-			
						-			
						-			
						-			
						-			
						-			
						-			
						-			
						-			
~~Subtotal~~	-				-	-	-	-	

~~Instructions for Account 281:~~

~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. 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.~~

~~PJM TRANSMISSION OWNER~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT-255~~	~~Beg of Year Balance~~ ~~p266.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~							-	-	
~~ADIT-255~~		~~End of Year Balance~~ ~~p267.h~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~								-	

~~Instructions for Account 255:~~
~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. 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.~~

~~Attachment H-4A, Attachment 5b~~
~~page 1 of 2~~
~~For the 12 months ended 12/31/2017~~

~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~	~~[8]~~	~~[9]~~
	~~2017 Quarterly Activity and Balances~~							
~~Beginning 190 (including adjustments)~~	~~Q1 Activity~~	~~Ending Q1~~	~~Q2 Activity~~	~~Ending Q2~~	~~Q3 Activity~~	~~Ending Q3~~	~~Q4 Activity~~	~~Ending Q4~~
~~Beginning 190 (including adjustments)~~	~~Pro-rated Q1~~		~~Pro-rated Q2~~		~~Pro-rated Q3~~		~~Pro-rated Q4~~	
~~Beginning 282 (including adjustments)~~	~~Q1 Activity~~	~~Ending Q1~~	~~Q2 Activity~~	~~Ending Q2~~	~~Q3 Activity~~	~~Ending Q3~~	~~Q4 Activity~~	~~Ending Q4~~
~~Beginning 282 (including adjustments)~~	~~Pro-rated Q1~~		~~Pro-rated Q2~~		~~Pro-rated Q3~~		~~Pro-rated Q4~~	
~~Beginning 283 Including adjustments)~~	~~Q1 Activity~~	~~Ending Q1~~	~~Q2 Activity~~	~~Ending Q2~~	~~Q3 Activity~~	~~Ending Q3~~	~~Q4 Activity~~	~~Ending Q4~~
~~Beginning 283 Including adjustments)~~	~~Pro-rated Q1~~		~~Pro-rated Q2~~		~~Pro-rated Q3~~		~~Pro-rated Q4~~	

~~Attachment H-4A, Attachment 5b~~
~~page 2 of 2~~
~~For the 12 months ended 12/31/2017~~

~~2017 Activity~~		~~[1]~~ ~~Transmission-only (including plant and labor related ADIT allocated to transmission) FERC Form 1 - Year-End 2017~~	~~[2]~~ ~~Prorated year-end less FERC Form 1 Year-end~~	~~[3]~~ ~~Sum of FAS143, FAS106, FAS109, and CIAC from Attachment 5 notes~~	~~[4]~~ ~~Total Normalization to Attachment 5 ((col. 1 - col. 3) - page 1, col. 9)~~	~~[5]~~ ~~Ending Balance for formula rate (col. 1 - col. 3. - col. 4)~~
~~Pro-rated Total~~	~~Pro-rated Ending 190~~					
~~Pro-rated Total~~	~~Pro-rated Ending 282~~					
~~Pro-rated Total~~	~~Pro-rated Ending 283~~					

~~Attachment H-4A, Attachment 6~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~1~~ **~~Calculation of PBOP Expenses~~**

~~2~~ **~~JCP&L~~**
~~3~~ ~~Total FirstEnergy PBOP expenses~~
~~4~~ ~~Labor dollars (FirstEnergy)~~
~~5~~ ~~cost per labor dollar (line 3 / line 4)~~
~~6~~ ~~labor (labor not capitalized) current year~~
~~7~~ ~~PBOP Expense for current year (line 5 * line 6)~~
~~8~~ ~~PBOP expense in all O&M and A&G accounts for current year~~
~~9~~ ~~PBOP Adjustment for Attachment H-4A, page 3, line 9 (line 7 - line 8)~~

~~10~~ ~~Lines 3-4 cannot change absent approval or acceptance by FERC in a separate proceeding~~

Attachment 13

~~Attachment H-4A, Attachment 7~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Taxes Other than Income Calculation~~

		~~[A]~~	~~Dec 31, 2017~~
~~1~~	**~~Payroll Taxes~~**		
~~1a~~		~~263.i~~	
~~1b~~		~~263.i~~	
~~1c~~		~~263.i~~	
~~1d~~		~~263.i~~	
~~1z~~	**~~Payroll Taxes Total~~**		
~~2~~	**~~Highway and Vehicle Taxes~~**		
~~2a~~		~~263.i~~	
~~2z~~	**~~Highway and Vehicle Taxes~~**		
~~3~~	**~~Property Taxes~~**		
~~3a~~		~~263.i~~	
~~3b~~		~~263.i~~	
~~3c~~		~~263.i~~	
~~3d~~		~~263.i~~	
~~3z~~	**~~Property Taxes~~**		
~~4~~	**~~Gross Receipts Tax~~**		
~~4a~~		~~263.i~~	
~~4z~~	**~~Gross Receipts Tax~~**		
~~5~~	**~~Other Taxes~~**		
~~5a~~		~~263.i~~	
~~5b~~		~~263.i~~	
~~5c~~		~~263.i~~	
~~5d~~			
~~5z~~	**~~Other Taxes~~**		
~~6z~~	**~~Payments in lieu of taxes~~**		
~~7~~	~~Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z)~~ ~~[tie to 114.14c]~~		

~~Notes:~~

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

~~Attachment H-4A, Attachment 8~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Capital Structure Calculation~~

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

~~Notes:~~

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

~~Attachment H-4A, Attachment 9~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Stated Value Inputs~~

~~Formula Rate Protocols~~
~~Section VIII.A~~

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

~~JCP&L's stated ROE is set to: 11.0%~~

~~2. Postretirement Benefits Other Than Pension ("PBOP")~~

~~*sometimes referred to as Other Post Employment Benefits, or "OPEB"~~

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

~~3. Depreciation Rates~~

~~FERC Account~~	~~Depr %~~
~~350.2~~	~~1.44%~~
~~352~~	~~1.33%~~
~~353~~	~~2.21%~~
~~354~~	~~1.29%~~
~~355~~	~~1.93%~~
~~356~~	~~2.60%~~
~~356.1~~	~~1.22%~~
~~357~~	~~1.53%~~
~~358~~	~~1.76%~~
~~359~~	~~1.21%~~
~~303~~	~~14.29%~~
~~390.1~~	~~1.61%~~
~~390.2~~	~~0.46%~~
~~391~~	~~10.91%~~
~~391.15~~	~~0.96%~~
~~391.2~~	~~6.39%~~
~~392~~	~~11.29%~~
~~393~~	~~3.13%~~
~~394~~	~~6.17%~~
~~395~~	~~16.27%~~
~~396~~	~~2.35%~~
~~397~~	~~5.13%~~
~~398~~	~~1.36%~~

Attachment 13

~~Attachment H-4A, Attachment 10~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Debt Cost Calculation~~

~~TABLE 1: Summary Cost of Long Term Debt~~

~~CALCULATION OF COST OF DEBT~~

~~YEAR ENDED 12/31/2017~~

		~~(a)~~	~~(b)~~	~~(c)~~	~~(d)~~	~~(e)~~	~~(f)~~	~~(g)~~	~~(h)~~	~~(i)~~	~~(j)~~	
~~Long Term Debt Cost at Year Ended:~~	~~t=N 12/31/2017~~	~~Issue Date~~	~~Maturity Date~~	~~ORIGINAL ISSUANCE (table 2, col. cc)~~	~~Net Proceeds At Issuance (table 2, col. hh)~~	~~Net Amount Outstanding at t=N~~	~~Months Outstanding at t=N~~	~~Average Net Outstanding in Year* z* ((col e. * col. F)/12)~~	~~Weighted Outstanding Ratios (col. g/col. g total)~~	~~Effective Cost Rate (Table 2, Col. ll)~~	~~Weighted Debt Cost at t = N (h) * (i)~~	
~~First Mortgage Bonds:~~												
~~(1)~~												
~~(2)~~												
~~(3)~~												
~~(4)~~												
~~(5)~~												
~~(6)~~												
~~(7)~~												
												~~**~~

~~t = time~~
~~The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.~~
~~The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.~~
~~* z = Average of monthly balances for months outstanding during the year (average of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).~~
~~Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).~~
~~** This Total Weighted Average Debt Cost will be shown on page 4, line 27, column 5 of formula rate Attachment H-4A.~~

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

~~YEAR ENDED 12/31/2017~~

		~~(aa)~~	~~(bb)~~	~~(cc)~~	~~(dd)~~	~~(ee)~~	~~(ff)~~	~~(gg)~~	~~(hh)~~	~~(ii)~~	~~(jj)~~	~~(kk)~~	~~(ll)~~
~~Long Term Debt Issuances~~	~~Affiliate~~	~~Issue Date~~	~~Maturity Date~~	~~Amount Issued~~	~~(Discount) Premium at Issuance~~	~~Issuance Expense~~	~~Loss/Gain on Reacquired Debt~~	~~Less Related ADIT~~	~~Net Proceeds (col. cc + col. dd + col. ee + col. ff)~~	~~Net Proceeds Ratio ((col. cc / col. hh) *100)~~	~~Coupon Rate~~	~~Annual Interest (col. cc *col. jj)~~	~~Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)~~
~~(1)~~													
~~(2)~~													
~~(3)~~													
~~(4)~~													
~~(5)~~													
~~(6)~~													
~~(7)~~													

~~* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation~~
~~Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_o equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).~~

~~Attachment H-4A, Attachment 11~~
~~page 1 of 2~~
~~For the 12 months ended 12/31/2017~~

~~Transmission Enhancement Charge (TEC) Worksheet~~

~~To be completed in conjunction with Attachment H-4~~

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

	~~(1)~~	~~(2)~~	~~(3)~~	~~(4)~~	~~(5)~~	~~(6)~~	~~(7)~~	~~(8)~~	~~(9)~~
~~Line No.~~		**~~Reference~~**	**~~Transmission~~**	**~~Allocator~~**	~~Line No.~~		**~~Reference~~**	**~~Transmission~~**	**~~Allocator~~**
~~1~~	~~Gross Transmission Plant - Total~~	~~Attach. H-4A, p. 2, line 2, col. 5 (Note A)~~							
~~2~~	~~Net Transmission Plant - Total~~	~~Attach. H-4A, p. 2, line 14, col. 5 (Note B)~~							
	~~O&M EXPENSE~~								
~~3~~	~~Total O&M Allocated to Transmission~~	~~Attach. H-4A, p. 3, line 15, col. 5~~							
~~4~~	~~Annual Allocation Factor for O&M~~	~~(line 3 divided by line 1, col. 3)~~							
	~~GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE~~								
~~5~~	~~Total G, I, & C depreciation expense~~	~~Attach. H-4A, p. 3, lines 17 & 18, col. 5~~							
~~6~~	~~Annual allocation factor for G, I, & C depreciation expense~~	~~(line 5 divided by line 1, col. 3)~~							
		~~TAXES OTHER THAN INCOME TAXES~~							
~~7~~	~~Total Other Taxes~~	~~Attach. H-4A, p. 3, line 28, col. 5~~							
~~8~~	~~Annual Allocation Factor for Other Taxes~~	~~(line 7 divided by line 1, col. 3)~~							
~~9~~	**~~Annual Allocation Factor for Expense~~**	**~~Sum of line 4, 6, & 8~~**							
	~~INCOME TAXES~~					~~INCOME TAXES~~			
~~10~~	~~Total Income Taxes~~	~~Attach. H-4A, p. 3, line 39, col. 5~~			~~10b~~	~~Total Income Taxes~~	~~Attachment 2, line 33~~		
~~11~~	~~Annual Allocation Factor for Income Taxes~~	~~(line 12 divided by line 2, col. 3)~~			~~11b~~	~~Annual Allocation Factor for Income Taxes~~	~~(line 10b divided by line 2, col. 3)~~		
	~~RETURN~~					~~RETURN~~			
~~12~~	~~Return on Rate Base~~	~~Attach. H-4A, p. 3, line 40, col. 5~~			~~12b~~	~~Return on Rate Base~~	~~Attachment 2, line 22~~		
~~13~~	~~Annual Allocation Factor for Return on Rate Base~~	~~(line 14 divided by line 2, col. 3)~~			~~13b~~	~~Annual Allocation Factor for Return on Rate Base~~	~~(line 12b divided by line 2, col. 3)~~		
~~14~~	**~~Annual Allocation Factor for Return~~**	**~~Sum of line 11 and 13~~**			**~~14b~~**	**~~Annual Allocation Factor for Return~~**	**~~Sum of line 11b and 13b~~**		
					~~15~~	**~~Additional Annual Allocation Factor for Return~~**	**~~Line 14 b, col. 9 less line 14, col. 4~~**		

Attachment 13

~~Attachment H-4A, Attachment 11~~
~~page 2 of 2~~
~~For the 12 months ended 12/31/2017~~

~~Transmission Enhancement Charge (TEC) Worksheet~~

~~To be completed in conjunction with Attachment H-4~~

	~~(1)~~	~~(2)~~	~~(3)~~	~~(4)~~	~~(5)~~	~~(6)~~	~~(7)~~	~~(8)~~	~~(9)~~	~~(10)~~	~~(11)~~	~~(12)~~	~~(13)~~	~~(14)~~
~~Line No.~~	~~Project Name~~	~~RTEP Project Number~~	~~Project Gross Plant~~	~~Annual Allocation Factor for Expense~~	~~Annual Expense Charge~~	~~Project Net Plant~~	~~Annual Allocation Factor for Return~~	~~Annual Return Charge~~	~~Project Depreciation Expense~~	~~Annual Revenue Requirement~~	~~Additional Incentive Annual Allocation Factor for Return (Note F)~~	~~Total Annual Revenue Requirement~~	~~True-up Adjustment~~	~~Net Revenue Requirement with True-up~~
			~~(Note C & H)~~	~~(Page 1, line 9)~~	~~(Col. 3 * Col. 4)~~	~~(Note D & H)~~	~~Page 1, line 14~~	~~(Col. 6 * Col. 7)~~	~~(Note E)~~	~~(Sum Col. 5, 8, & 9)~~	~~(Col. 6 * Page 1, line 15, Col. 9)~~	~~(Sum Col. 10 & 11)~~	~~(Note G)~~	~~(Sum Col. 12 & 13)~~
~~2a~~														
~~2b~~														
~~2c~~														
~~2d~~														
~~2e~~														
~~2f~~														
~~2g~~														

~~3 Transmission Enhancement Credit taken to Attachment H-4A Page 1, Line 7~~
~~4 Additional Incentive Revenue taken to Attachment H-4A, Page 3, Line 42~~

~~Notes~~

~~A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-4A.~~
~~B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-4A.~~
~~C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.~~
~~D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.~~
~~E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-4A, page 3, line 16.~~
~~F Any actual ROE incentive must be approved by the Commission~~
~~G True-up adjustment is calculated on the project true-up schedule, attachment 12 column j~~
~~H Based on a 13-month average~~

Attachment 13

~~Attachment H-4A, Attachment 11a~~
~~page 1 of 2~~
~~For the 12 months ended 12/31/2017~~

~~Transmission Enhancement Charge (TEC) Worksheet~~

~~To be completed in conjunction with Attachment H-4A~~

~~Line No.~~	~~Project Name~~	~~RTEP Project Number~~	~~Project Gross Plant~~	~~Dec-16~~	~~Jan-17~~	~~Feb-17~~	~~Mar-17~~	~~Apr-17~~	~~May-17~~	~~Jun-17~~	~~Jul-17~~	~~Aug-17~~	~~Sep-17~~	~~Oct-17~~	~~Nov-17~~	~~Dec-17~~
			~~(Note A)~~													
~~2a~~																
~~2b~~																
~~2c~~																
~~2d~~																
~~2e~~																
~~2f~~																
~~2g~~																

~~NOTE:~~

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

Attachment 13

~~**Transmission Enhancement Charge (TEC) Worksheet**~~ ~~Attachment H-4A, Attachment 11a~~

~~To be completed in conjunction with Attachment H-4A~~ ~~page 2 of 2~~

~~For the 12 months ended 12/31/2017~~

~~**Accumulated Depreciation**~~	~~**Dec-16**~~	~~**Jan-17**~~	~~**Feb-17**~~	~~**Mar-17**~~	~~**Apr-17**~~	~~**May-17**~~	~~**Jun-17**~~	~~**Jul-17**~~	~~**Aug-17**~~	~~**Sep-17**~~	~~**Oct-17**~~	~~**Nov-17**~~	~~**Dec-17**~~	~~**Project Net Plant**~~
~~(Note B)~~														~~(Note B & C)~~

~~NOTE~~

~~[B] Utilizing a 13-month average.~~ ~~[C] Taken to Attachment 11, Page 2, Col. 6~~

~~Attachment H-4A, Attachment 12~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Transmission Enhancement Charge (TEC) Worksheet~~

~~To be completed in conjunction with Attachment H-4A~~

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

~~NOTE~~

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

~~Attachment H-4A, Attachment 13~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Net Revenue Requirement True-up with Interest~~

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

			~~Over (Under) Recovery Plus Interest~~	**~~Average Monthly Interest Rate~~**	**~~Months~~**	**~~Calculated Interest~~**	**~~Amortization~~**	**~~Surcharge (Refund) Owed~~**
~~2~~	~~Interest Rate on Amount of Refunds or Surcharges from 35.19a~~			~~%~~				
	~~An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017~~							
	~~Calculation of Interest~~					**~~Monthly~~**		
~~3~~	~~January~~	~~Year 2015~~	~~-~~	~~%~~	~~12~~	~~-~~		~~-~~
~~4~~	~~February~~	~~Year 2015~~	~~-~~	~~%~~	~~11~~	~~-~~		~~-~~
~~5~~	~~March~~	~~Year 2015~~	~~-~~	~~%~~	~~10~~	~~-~~		~~-~~
~~6~~	~~April~~	~~Year 2015~~	~~-~~	~~%~~	~~9~~	~~-~~		~~-~~
~~7~~	~~May~~	~~Year 2015~~	~~-~~	~~%~~	~~8~~	~~-~~		~~-~~
~~8~~	~~June~~	~~Year 2015~~	~~-~~	~~%~~	~~7~~	~~-~~		~~-~~
~~9~~	~~July~~	~~Year 2015~~	~~-~~	~~%~~	~~6~~	~~-~~		~~-~~
~~10~~	~~August~~	~~Year 2015~~	~~-~~	~~%~~	~~5~~	~~-~~		~~-~~
~~11~~	~~September~~	~~Year 2015~~	~~-~~	~~%~~	~~4~~	~~-~~		~~-~~
~~12~~	~~October~~	~~Year 2015~~	~~-~~	~~%~~	~~3~~	~~-~~		~~-~~
~~13~~	~~November~~	~~Year 2015~~	~~-~~	~~%~~	~~2~~	~~-~~		~~-~~
~~14~~	~~December~~	~~Year 2015~~	~~-~~	~~%~~	~~1~~	~~-~~		~~-~~
						~~-~~		~~-~~
						~~Annual~~		
~~15~~	~~January through December~~	~~Year 2016~~	~~-~~	~~%~~	~~12~~	~~-~~		~~-~~
	~~Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months~~					**~~Monthly~~**		
~~16~~	~~January~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~17~~	~~February~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~18~~	~~March~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~19~~	~~April~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~20~~	~~May~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~21~~	~~June~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~22~~	~~July~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~23~~	~~August~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~24~~	~~September~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~25~~	~~October~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~26~~	~~November~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
~~27~~	~~December~~	~~Year 2017~~	~~-~~	~~%~~		~~-~~	~~-~~	~~-~~
						~~-~~		
~~28~~	~~True-Up with Interest~~						~~$ -~~	
~~29~~	~~Less Over (Under) Recovery~~						~~$ -~~	
~~30~~	~~Total Interest~~						~~$ -~~	

Attachment 13

~~Attachment H-4A, Attachment 13a~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~TEC Revenue Requirement True-up with Interest~~

	~~TEC Reconciliation Revenue Requirement For Year 2015 Available May 1, 2016~~		~~TEC 015 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2014~~		~~True-up Adjustment - Over (Under) Recovery~~
~~1~~	~~$0~~	-	~~$0~~	=	~~$0~~

			~~Over (Under) Recovery Plus Interest~~	~~Average Monthly Interest Rate~~	~~Months~~	~~Calculated Interest~~	~~Amortization~~	~~Surcharge (Refund) Owed~~
2	~~Interest Rate on Amount of Refunds or Surcharges from 35.19a~~			~~%~~				

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

	~~Calculation of Interest~~					~~Monthly~~		
~~3~~	~~January~~	~~Year 2015~~	-	~~%~~	~~12~~	-		-
~~4~~	~~February~~	~~Year 2015~~	-	~~%~~	~~11~~	-		-
~~5~~	~~March~~	~~Year 2015~~	-	~~%~~	~~10~~	-		-
~~6~~	~~April~~	~~Year 2015~~	-	~~%~~	~~9~~	-		-
~~7~~	~~May~~	~~Year 2015~~	-	~~%~~	~~8~~	-		-
~~8~~	~~June~~	~~Year 2015~~	-	~~%~~	~~7~~	-		-
~~9~~	~~July~~	~~Year 2015~~	-	~~%~~	~~6~~	-		-
~~10~~	~~August~~	~~Year 2015~~	-	~~%~~	~~5~~	-		-
~~11~~	~~September~~	~~Year 2015~~	-	~~%~~	~~4~~	-		-
~~12~~	~~October~~	~~Year 2015~~	-	~~%~~	~~3~~	-		-
~~13~~	~~November~~	~~Year 2015~~	-	~~%~~	~~2~~	-		-
~~14~~	~~December~~	~~Year 2015~~	-	~~%~~	~~1~~	-		-
						-		-
						~~Annual~~		
~~15~~	~~January through December~~	~~Year 2016~~	-	~~%~~	~~12~~	-		-

	~~Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months~~					~~Monthly~~		
~~16~~	~~January~~	~~Year 2017~~	-	~~%~~		-	-	-
~~17~~	~~February~~	~~Year 2017~~	-	~~%~~		-	-	-
~~18~~	~~March~~	~~Year 2017~~	-	~~%~~		-	-	-
~~19~~	~~April~~	~~Year 2017~~	-	~~%~~		-	-	-
~~20~~	~~May~~	~~Year 2017~~	-	~~%~~		-	-	-
~~21~~	~~June~~	~~Year 2017~~	-	~~%~~		-	-	-
~~22~~	~~July~~	~~Year 2017~~	-	~~%~~		-	-	-
~~23~~	~~August~~	~~Year 2017~~	-	~~%~~		-	-	-
~~24~~	~~September~~	~~Year 2017~~	-	~~%~~		-	-	-
~~25~~	~~October~~	~~Year 2017~~	-	~~%~~		-	-	-
~~26~~	~~November~~	~~Year 2017~~	-	~~%~~		-	-	-
~~27~~	~~December~~	~~Year 2017~~	-	~~%~~		-	-	-
						-		

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

~~Attachment H-4A, Attachment 14~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Other Rate Base Items~~

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

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

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

~~Notes:~~

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

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

~~[C]~~ ~~Prepayments shall exclude prepayments of income taxes.~~

~~[D]~~ ~~Includes transmission-related balance only~~

~~Attachment H-4A, Attachment 15~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Income Tax Adjustments~~

	~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~
			~~Beg/End Average [C]~~	~~Dec 31, 2016~~	~~Dec 31, 2017~~
~~1~~	~~Tax adjustment for Permanent Differences & AFUDC Equity~~	~~[A]~~			
~~2~~	~~Amortized Excess Deferred Taxes (enter negative)~~	~~[B]~~			
~~3~~	~~Amortized Deficient Deferred Taxes~~	~~[B]~~			

~~Notes:~~

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

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

~~[C]~~ ~~Beg/End Average for line 1 taken to Attachment H-4A, page 3, line 33; Beg/End Average for lines 2-3 taken to Attachment H-4A, page 3, line 34~~

Attachment 13

~~Attachment H-4A, Attachment 16a~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Regulatory Asset - Storms~~

	~~[1]~~		~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~
~~1~~	~~**Monthly Balance**~~		~~Source~~	~~Months Remaining In Amortization Period~~	~~Beginning Balance~~	~~Amortization Expense (Company Records)~~	~~Additions (Deductions)~~	~~Ending Balance~~
~~2~~	~~December~~	~~2016~~	~~p232 (and Notes)~~					
~~3~~	~~January~~	~~2017~~	~~company records~~					
~~4~~	~~February~~		~~company records~~					
~~5~~	~~March~~		~~company records~~					
~~6~~	~~April~~		~~company records~~					
~~7~~	~~May~~		~~company records~~					
~~8~~	~~June~~		~~company records~~					
~~9~~	~~July~~		~~company records~~					
~~10~~	~~August~~		~~company records~~					
~~11~~	~~September~~		~~company records~~					
~~12~~	~~October~~		~~company records~~					
~~13~~	~~November~~		~~company records~~					
~~14~~	~~December~~	~~2017~~	~~p232 (and Notes)~~					
~~15~~	~~**Ending Balance 13-Month Average**~~		~~(sum lines 2-14) /13~~					
						~~Attachment H-4A, page 3, line 12~~		~~Attachment H-4A, page 2, Line 27~~

Attachment 13

~~Attachment H-4A, Attachment 16b~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Regulatory Asset - Vegetation Management~~

	~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~
~~1~~	**~~Monthly Balance~~**	~~Source~~	~~Months Remaining In Amortization Period~~	~~Beginning Balance~~	~~Amortization Expense (Company Records)~~	~~Additions (Deductions)~~	~~Ending Balance~~
~~2~~	~~December 2016~~	~~p232 (and Notes)~~					
~~3~~	~~January 2017~~	~~company records~~					
~~4~~	~~February~~	~~company records~~					
~~5~~	~~March~~	~~company records~~					
~~6~~	~~April~~	~~company records~~					
~~7~~	~~May~~	~~company records~~					
~~8~~	~~June~~	~~company records~~					
~~9~~	~~July~~	~~company records~~					
~~10~~	~~August~~	~~company records~~					
~~11~~	~~September~~	~~company records~~					
~~12~~	~~October~~	~~company records~~					
~~13~~	~~November~~	~~company records~~					
~~14~~	~~December 2017~~	~~p232 (and Notes)~~					
~~15~~	**~~Ending Balance 13-Month Average~~**	~~(sum lines 2-14) /13~~					
					~~Attachment H-4A, page 3, line 12~~		~~Attachment H-4A, page 2, Line 27~~

~~Attachment H-4A, Attachment 16c~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Regulatory Asset – Formula Rate Development Costs~~

	~~[1]~~		~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~
~~1~~	~~**Monthly Balance**~~		~~Source~~	~~Months Remaining In Amortization Period~~	~~Beginning Balance~~	~~Amortization Expense (Company Records)~~	~~Additions (Deductions)~~	~~Ending Balance~~
~~2~~	~~December~~	~~2016~~	~~p232 (and Notes)~~					
~~3~~	~~January~~	~~2017~~	~~company records~~					
~~4~~	~~February~~		~~company records~~					
~~5~~	~~March~~		~~company records~~					
~~6~~	~~April~~		~~company records~~					
~~7~~	~~May~~		~~company records~~					
~~8~~	~~June~~		~~company records~~					
~~9~~	~~July~~		~~company records~~					
~~10~~	~~August~~		~~company records~~					
~~11~~	~~September~~		~~company records~~					
~~12~~	~~October~~		~~company records~~					
~~13~~	~~November~~		~~company records~~					
~~14~~	~~December~~	~~2017~~	~~p232 (and Notes)~~					
~~15~~	~~**Ending Balance 13-Month Average**~~		~~(sum lines 2-14) /13~~					
						~~Attachment H-4A, page 3, line 12~~		~~Attachment H-4A, page 2, Line 27~~

Attachment 13

~~Attachment H-4A, Attachment 17~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Abandoned Plant~~

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

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

~~Attachment H-4A, Attachment 18~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

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

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

~~Attachment H-4A, Attachment 19~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Federal Income Tax Rate~~

~~Nominal Federal Income Tax Rate (entered on Attachment H-4A, page 5 of 5, Note K)~~	

~~State Income Tax Rate~~

	~~New Jersey~~	~~Combined Rate (entered on Attachment H-4A, page 5 of 5, Note K)~~
~~Nominal State Income Tax Rate~~		
~~Times Apportionment Percentage~~		
~~Combined State Income Tax Rate~~		

ATTACHMENT H-4B

[Reserved]

~~Jersey Central Power & Light Company~~

~~Formula Rate Implementation Protocols~~

~~ANNUAL TRUE-UP, INFORMATION EXCHANGE, AND CHALLENGE PROCEDURES~~

~~Definitions~~

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

~~"Annual Update" means JCP&L's ATRR for the preceding calendar year, as well as the True-up for the prior Rate Year, as posted on or before June 1 of each year.~~

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

~~"Formula Rate" means these protocols (to be included as Attachment H-4B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.~~

~~"Formula Rate Template" means the collection of formulas and worksheets, unpopulated with any data, to be included as Attachment H-4A of the PJM Tariff.~~

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

~~"Preliminary Challenge" means a written challenge to the Annual Update or Projected Transmission Revenue Requirement submitted to JCP&L as provided in Section IV below.~~

~~"Projected Transmission Revenue Requirement" or "PTRR" means the projected net transmission revenue requirement calculated for the forthcoming Rate Year, as well as, where applicable, the most recently calculated True-up, with interest, to be posted on the PJM website no later than October 31 of each year for rates effective the next calendar year starting January 1.~~

~~"Publication Date" means the date on which the Annual Update is posted.~~

~~"Rate Year" means the twelve consecutive month period that begins on January 1 and continues through~~

~~December 31.~~

~~"True-up" means the difference between the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) and the ATRR for the same Rate Year, which shall be provided in the Annual Update on or before June 1 of the year subsequent to the Rate Year. The True-up will be a component of the PTRR.~~

~~Section I. Applicability~~

~~The following procedures shall apply to the Jersey Central Power & Light Company ("JCP&L") calculation of its Actual Transmission Revenue Requirement, True-up, and Projected Transmission Revenue Requirement.~~

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

~~A. On or before June 1 of each year subsequent to calendar year 2017, JCP&L shall determine its Annual Update for the immediately preceding calendar year under Attachment H-4A and Section VII of these protocols, including calculation of the True-up to be included in JCP&L's PTRR for the subsequent Rate Year.~~

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

~~C. On or before October 31, 2017, and on or before each subsequent October 31, JCP&L shall provide the PTRR to PJM and cause such information to be posted on the PJM website, in both a Portable Document Format ("PDF") and fully-functioning Excel file, and within two (2) days of posting of the PTRR, PJM shall provide notice of such posting via an e-mail exploder list.~~

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

~~E. The ATRR shall:~~

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

~~2. Be based on JCP&L's FERC Form No. 1 for the prior calendar year;~~

~~3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the ATRR that are not otherwise~~

~~available in the FERC Form No. 1, subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC's Model Protective Order;~~

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

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

~~6. Identify and, to the extent not explained in a worksheet included in the ATRR, explain, all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;~~

~~7. Provide underlying data for Formula Rate inputs that provide greater granularity than is required for the FERC Form No. 1;~~

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

  ~~a. Identify any Accounting Change, including:~~

    ~~i. the initial implementation of an accounting standard or policy;~~

    ~~ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;~~

    ~~iii. correction of errors and prior period adjustments that affect the ATRR and True-up calculation;~~

    ~~iv. the implementation of new estimation methods or policies that change prior estimates; and~~

    ~~v. changes to income tax elections;~~

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

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

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

~~9. Include for the applicable Rate Year the following information related to affiliate cost allocation: (A) a detailed description of the methodologies used to allocate and directly~~

~~assign costs between JCP&L and its affiliates by service category and function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; and (B) the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function.~~

~~F. The Projected Transmission Revenue Requirement shall:~~

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

~~2. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the PTRR;~~

~~3. Provide sufficient information to enable Interested Parties to replicate the calculation of the PTRR;~~

~~4. With respect to any Accounting Change:~~

~~a. Identify any Accounting Change, including:~~

~~i. the initial implementation of an accounting standard or policy;~~

~~ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;~~

~~iii. correction of errors and prior period adjustments that affect the PTRR calculation;~~

~~iv. the implementation of new estimation methods or policies that change prior estimates; and~~

~~v. changes to income tax elections.~~

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

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

~~d. Provide, for each item identified pursuant to items II.F.4.a – II.F.4.c of these protocols, a narrative explanation of the individual impact of such change on the PTRR.~~

~~G. JCP&L shall hold an open meeting among Interested Parties ("Annual Update Meeting"), to be conducted via Internet webcast, no earlier than ten (10) business days following the Publication Date and no later than June 25. No fewer than seven (7) days prior to such Annual Update~~

~~Meeting, JCP&L shall provide notice on PJM's website of the time and date of the Annual Update Meeting, and PJM shall provide notice of the posting via an e-mail exploder list. The Annual Update Meeting shall: (i) permit JCP&L to explain and clarify its ATRR and True-up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the ATRR and True-up.~~

~~H. JCP&L shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting"), to be conducted via Internet webcast, no earlier than five (5) business days following the posting of the PTRR (as described in Section II.C of these protocols) and no later than November 30. No fewer than five (5) days prior to such Annual Projected Rate Meeting, JCP&L shall provide notice on PJM's website of the time and date of the Annual Projected Rate Meeting, and PJM shall provide notice of the posting via an e-mail exploder list. The Annual Projected Rate Meeting shall: (i) permit JCP&L to explain and clarify its PTRR and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the PTRR.~~

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

~~Section III. Information Exchange Procedures~~

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

~~A. Interested Parties shall have until January 15 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) to serve reasonable information and document requests on JCP&L ("Information Exchange Period"). If January 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:~~

~~1. the extent or effect of an Accounting Change;~~

~~2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols;~~

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

~~4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR or PTRR;~~

~~5. the prudence of actual costs and expenditures;~~

~~6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or~~

~~7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.~~

~~The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.~~

~~B. JCP&L shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. JCP&L shall respond to all information and document requests by no later than February 25 following the Publication Date, unless the Information Exchange Period is extended by JCP&L or FERC.~~

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

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

~~Section IV. Challenge Procedures~~

~~A. Interested Parties shall have until March 31 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) ("Review Period"), to review the inputs, supporting explanations, allocations and calculations and to notify JCP&L in writing, which may be made electronically, of any specific Preliminary Challenges to the Annual Update or PTRR. If the final day of the Review Period falls on a holiday recognized by FERC, the deadline for submitting all Preliminary Challenges shall be extended to the next business day. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update or PTRR shall bar pursuit of such issue with respect to that Annual Update or PTRR under the challenge procedures set forth in these protocols, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update or PTRR.~~

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

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

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

~~3. JCP&L, and where applicable, PJM, shall appoint a senior representative to work with the party that submitted the Preliminary Challenge (or its representative) toward a~~

~~resolution of the challenge.~~

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

~~5. No Preliminary Challenge may be submitted after March 31, and JCP&L must respond to all Preliminary Challenges by no later than April 30 unless the Review Period is extended by JCP&L or FERC, or as provided in Section IV.A above.~~

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

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

~~1. A Formal Challenge shall:~~

~~a. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;~~

~~b. Explain how the action or inaction violates the filed rate formula or protocols;~~

~~c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:~~

~~(i) the extent or effect of an Accounting Change;~~

~~(ii) whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols;~~

~~(iii) the proper application of the Formula Rate and procedures in these protocols;~~

~~(iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the ATRR or PTRR;~~

~~(v) the prudence of actual costs and expenditures;~~

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

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

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

~~action or inaction;~~

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

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

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

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

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

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

~~1. the extent or effect of an Accounting Change;~~

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

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

~~4. the accuracy of data and consistency with the formula rate of the calculations shown in the ATRR and PTRR;~~

~~5. the prudence of actual costs and expenditures;~~

~~6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or~~

~~7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.~~

~~E. Any changes or adjustments to the ATRR and PTRR resulting from the information exchange and Preliminary Challenge processes that are agreed to by JCP&L will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by JCP&L on or before December 1 will be reflected in the PTRR for the~~

~~upcoming Rate Year. Any changes or adjustments agreed to by JCP&L after December 1 will be reflected in the following year's Annual Update, as discussed in Section V of these protocols.~~

~~F. An Interested Party shall have until June 1 following the Review Period (unless such date is extended with the written consent of JCP&L to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with FERC, which shall be served on JCP&L on the date of such filing as specified in Section IV.C.2 above. A Formal Challenge shall be filed in the same docket as JCP&L's Informational Filing discussed in Section VI of these protocols. JCP&L shall respond to the Formal Challenge by the deadline established by FERC. An Interested Party may not pursue a Formal Challenge unless it submitted a Preliminary Challenge on some issue (which may be different from the Formal Challenge issue) during the applicable Review Period.~~

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

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

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

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

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

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

~~Section VI. Informational Filings~~

~~A. By June 1 of each year, JCP&L shall submit to FERC an informational filing ("Informational Filing") of its PTRR for the Rate Year, including its ATRR and True-up. This Informational Filing must include information that is reasonably necessary to determine:~~

~~1. that input data under the Formula Rate are properly recorded in any underlying work papers;~~

~~2. that JCP&L has properly applied the Formula Rate and these procedures;~~

~~3. the accuracy of data and the consistency with the Formula Rate of the transmission revenue requirement and rates under review;~~

~~4. the extent of Accounting Changes that affect Formula Rate inputs; and~~

~~5. the reasonableness of projected costs.~~

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

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

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

~~B. Any challenges to the implementation of the formula rate must be made through the challenge procedures described in Section IV of these protocols or in a separate complaint proceeding, and~~

~~not in response to the Informational Filing.~~

~~Section VII. Calculation of True-up~~

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

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

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

~~ii. Interest on any True-up shall be based on the Commission's interest rate on refunds as determined in accordance with 18 C.F.R. § 35.19a. Interest rates will be used to calculate the time value of money for the period that the True-up exists. The interest rate to be applied to the True-up will be determined using the average rate for the twenty (20) months preceding September of the current year.~~

~~B. JCP&L will post on PJM's website all information relating to the True-up as part of the Annual Update.~~

~~Section VIII. Formula Rate Inputs~~

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

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

~~Federal Power Act section 206.~~

SCHEDULE 12 – APPENDIX

(4) Jersey Central Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0123	Add 180 MVAR of distributed capacitors. 65 MVAR in northern JCPL and 115 MVAR in southern JCPL		JCPL (100%)
b0124.1	Add a 72 MVAR capacitor at Kittatinny 230 kV		JCPL (100%)
b0124.2	Add a 130 MVAR capacitor at Manitou 230 kV		JCPL (100%)
b0132	Reconductor Portland – Kittatinny 230 kV with 1590 ACSS		JCPL (100%)
b0132.1	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Kittatinny bus		JCPL (100%)
b0132.2	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Portland bus		JCPL (100%)
b0173	Replace a line trap at Newton 230kV substation for the Kittatinny-Newton 230kV circuit		JCPL (100%)
b0174	Upgrade the Portland – Greystone 230kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $1,442,372 2018: $1,273,748 2019: $1,235,637	JCPL (35.40%) / Neptune* (5.67%) / PSEG (54.37%) RE (2.94%) / ECP** (1.62%)
b0199	Greystone 230kV substation: Change Tap of limiting CT and replace breaker on the Greystone Whippany (Q1031) 230kV line		JCPL (100%)
b0200	Greystone 230kV substation: Change Tap of limiting CT on the West Wharton Greystone (E1045) 230kV line		JCPL (100%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0202	Kittatinny 230kV substation: Replace line trap on Kittatinny Pohatcong (L2012) 230kV line; Pohatcong 230kV substation: Change Tap of limiting CT on Kittatinny Pohatcong (L2012) 230kV line		JCPL (100%)
b0203	Smithburg 230kV Substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line; East Windsor 230kV substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line		JCPL (100%)
b0204	Install 72Mvar capacitor at Cookstown 230kV substation		JCPL (100%)
b0267	Reconductor JCPL 2 mile portion of Kittatinny – Newton 230 kV line		JCPL (100%)
b0268	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $734,194 2018: $646,180 2019: $628,066	JCPL (61.77%) / Neptune* (3%) / PSEG (32.73%) / RE (1.45%) / ECP** (1.05%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0279.1	Install 100 MVAR capacitor at Glen Gardner substation		JCPL (100%)
b0279.2	Install MVAR capacitor at Kittatinny 230 kV substation		JCPL (100%)
b0279.3	Install 17.6 MVAR capacitor at Freneau 34.5 kV substation		JCPL (100%)
b0279.4	Install 6.6 MVAR capacitor at Waretown #1 bank 34.5 kV substation		JCPL (100%)
b0279.5	Install 10.8 MVAR capacitor at Spottswood #2 bank .4.5 kV substation		JCPL (100%)
b0279.6	Install 6.6 MVAR capacitor at Pequannock N bus 34.5 kV substation		JCPL (100%)
b0279.7	Install 6.6 MVAR capacitor at Haskell P bus 34.5 kV substation		JCPL (100%)
b0279.8	Install 6.6 MVAR capacitor at Pinewald #2 Bank 34.5 kV substation		JCPL (100%)
b0279.9	Install 6.6 MVAR capacitor at Matrix 34.5 kV substation		JCPL (100%)
b0279.10	Install 6.6 MVAR capacitor at Hamburg Boro Q Bus 34.5 kV substation		JCPL (100%)
b0279.11	Install 6.6 MVAR capacitor at Newburg Q Bus 34.5 kV substation		JCPL (100%)
b0286	Install 130 MVAR capacitor at Whippany 230 kV		JCPL (100%)
b0289	Install 600 MVAR Dynamic Reactive Device in the Whippany 230 kV vicinity		AEC (0.65%) / JCPL (30.37%) / Neptune* (4.96%) / PSEG (59.65%) / RE (2.66%) / ECP** (1.71%)
b0289.1	Install additional 130 MVAR capacitor at West Wharton 230 kV substation		JCPL (100%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0292	Replace a 1600A line trap at Atlantic Larrabee 230 kV substation		JCPL (100%)
b0350	Implement Operating Procedure of closing the Glendon – Gilbert 115 kV circuit		JCPL (100%)
b0356	Replace wave trap on the Portland – Greystone 230 kV		JCPL (100%)
b0361	Change tap of limiting CT at Morristown 230 kV		JCPL (100%)
b0362	Change tap setting of limiting CT at Pohatcong 230 kV		JCPL (100%)
b0363	Change tap setting of limiting CT at Windsor 230 kV		JCPL (100%)
b0364	Change tap setting of CT at Cookstown 230 kV		JCPL (100%)
b0423.1	Upgrade terminal equipment at Readington (substation conductor)		JCPL (100%)
b0520	Replace Gilbert circuit breaker 12A		JCPL (100%)
b0657	Construct Boston Road 34.5 kV stations, construct Hyson 34.5 stations, add a 7.2 MVAR capacitor at Boston Road 34.5 kV		JCPL (100%)
b0726	Add a 2nd Raritan River 230/115 kV transformer	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $950,666 2018: $846,872 2019: $827,854	AEC (2.45%) / JCPL (97.55%)
b1020	Replace wave trap at Englishtown on the Englishtown - Manalapan circuit		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1075	Replace the West Wharton - Franklin - Vermont D931 and J932 115 kV line conductors with 1590 45/7 ACSR wire between the tower structures 78 and 78-B		JCPL (100%)
b1154.1	Upgrade the Whippany 230 kV breaker 'JB'		JCPL (100%)
b1155.1	Upgrade the Red Oak 230 kV breaker 'G1047'		JCPL (100%)
b1155.2	Upgrade the Red Oak 230 kV breaker 'T1034'		JCPL (100%)
b1345	Install Martinsville 4-breaker 34.5 rink bus		JCPL (100%)
b1346	Reconductor the Franklin – Humburg (R746) 4.7 miles 34.5 kV line with 556 ACSR and build 2.7 miles 55 ACSR line extension to Sussex		JCPL (100%)
b1347	Replace 500 CU substation conductor with 795 ACSR on the Whitesville – Asbury Tap 34.5 kV (U47) line		JCPL (100%)
b1348	Upgrade the Newton – North Newton 34.5 kV (F708) line by adding a second underground 1250 CU egress cable		JCPL (100%)
b1349	Reconductor 5.2 miles of the Newton – Woodruffs Gap 34.5 kV (A703) line with 556 ACSR		JCPL (100%)
b1350	Upgrade the East Flemington – Flemington 34.5 kV (V724) line by adding second underground 1000 AL egress cable and replacing 4/0		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1351	Add 34.5 kV breaker on the Larrabee A and D bus tie		JCPL (100%)
b1352	Upgrade the Smithburg – Centerstate Tap 34.5 kV (X752) line by adding second 200 ft underground 1250 CU egress cable		JCPL (100%)
b1353	Upgrade the Larrabee – Laurelton 34.5 kV (Q43) line by adding second 700 ft underground 1250 CU egress cable		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1354	Add four 34.5 kV breakers and re-configure A/B bus at Rockaway		JCPL (100%)
b1355	Build a new section 3.3 miles 34.5 kV 556 ACSR line from Riverdale to Butler		JCPL (100%)
b1357	Build 10.2 miles new 34.5 kV line from Larrabee – Howell		JCPL (100%)
b1359	Install a Troy Hills 34.5 kV by-pass switch and reconfigure the Montville – Whippany 34.5 kV (D4) line		JCPL (100%)
b1360	Reconductor 0.7 miles of the Englishtown – Freehold Tap 34.5 kV (L12) line with 556 ACSR		JCPL (100%)
b1361	Reconductor the Oceanview – Neptune Tap 34.5 kV (D130) line with 795 ACSR		JCPL (100%)
b1362	Install a 23.8 MVAR capacitor at Wood Street 69 kV		JCPL (100%)
b1364	Upgrade South Lebanon 230/69 kV transformer #1 by replacing 69 kV substation conductor with 1590 ACSR		JCPL (100%)
b1399.1	Upgrade the Whippany 230 kV breaker ‘QJ’		JCPL (100%)
b1673	Rocktown - Install a 230/34.5 kV transformer by looping the Pleasant Valley - E Flemington 230 kV Q-2243 line (0.4 miles) through the Rocktown Substation		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1674	Build a new Englishtown - Wyckoff St 15 mile, 115 kV line and install 115/34.5 kV transformer at Wyckoff St		JCPL (100%)
b1689	Atlantic Sub - 230 kV ring bus reconfiguration. Put a “source” between the Red Bank and Oceanview “loads”		JCPL (100%)
b1690	Build a new third 230 kV line into the Red Bank 230 kV substation		JCPL (100%)
b1853	Install new 135 MVA 230/34.5 kV transformer with one 230 kV CB at Eaton Crest and create a new 34.5 kV CB straight bus to feed new radial lines to Locust Groove and Interdata/Woodbine		JCPL (100%)
b1854	Readington I737 34.5 kV Line - Parallel existing 1250 CU UG cable (440 feet)		JCPL (100%)
b1855	Oceanview Substation - Relocate the H216 breaker from the A bus to the B bus		JCPL (100%)
b1856	Madison Tp to Madison (N14) line - Upgrade limiting 250 Cu substation conductor with 795 ACSR at Madison sub		JCPL (100%)
b1857	Montville substation - Replace both the 397 ACSR and the 500 Cu substation conductor with 795 ACSR on the 34.5 kV (M117) line		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1858	Reconductor the Newton - Mohawk (Z702) 34.5 kV line with 1.9 miles of 397 ACSR		JCPL (100%)
b2003	Construct a Whippany to Montville 230 kV line (6.4 miles)		JCPL (100%)
b2015	Build a new 230 kV circuit from Larrabee to Oceanview	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $9,616,241 2018: $18,839,128 2019: $19,935,489	JCPL (35.83%) / NEPTUNE* (23.61%) / HTP (1.77%) / ECP** (1.49%) / PSEG (35.87%) / RE (1.43%)
b2147	At Deep Run, install 115 kV line breakers on the B2 and C3 115 kV lines		JCPL (100%)

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EXHIBIT 3

Depreciation Rates

Attachment 13

Jersey Central Power & Light Company
ER17-217

Depreciation Rates

FERC Account	Depr %
350.2	1.44%
352	1.33%
353	2.21%
354	1.29%
355	1.93%
356	2.60%
356.1	1.22%
357	1.53%
358	1.76%
359	1.21%
303	14.29%
390.1	1.61%
390.2	0.46%
391	10.91%
391.15	0.96%
391.2	6.39%
392	11.29%
393	3.13%
394	6.17%
395	16.27%
396	2.35%
397	5.13%
398	1.36%