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VIA ELECTRONIC MAIL & REGULAR MAIL

June 17, 2013

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, 2011
-and-
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2012
-and-
In the Matter of the Provision of Basic Generation Service
for the Period Beginning June 1, 2013

Docket Nos. EO03050394, , ER10040287, EO11040250, ER12060485

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

Kristi Izzo, Secretary
Board of Public Utilities
44 South Clinton Avenue, 9th Fl
Post Office Box 350
Trenton, NJ 08625-0350

Dear Secretary Izzo:

Enclosed for filing on behalf of Jersey Central Power & Light Company ("JCP&L"), Public Service Electric and Gas Company ("PSE&G") and Rockland Electric Company ("RECO") (collectively, the "EDCs") please find an original and 10 copies of tariff sheets and supporting exhibits proposed by each of the EDCs and revised to reflect changes to the PJM Open Access Transmission Tariff ("OATT") made in response to: (i) the annual formula rate update filings made by PPL Electric Utilities Corporation ("PPL") in Federal Energy Regulatory Commission ("FERC") Docket No. ER09-1148, by American Electric Power Service Corporation ("AEP") in

FERC Docket No. ER08-1329 and ER10-335, and by Trans-Allegheny Interstate Line Company ("TrAILCo") in FERC Docket No. ER07-562, and (ii) the formula rate update filings made by the public utility affiliates of Pepco Holdings Inc. ("PHI") in FERC Docket No. ER08-1423 and the respective utility affiliate compliance filings for formula rate updates made by Atlantic City Electric Company ("ACE") in Docket No ER09-1156, Delmarva Power and Light ("Delmarva") in Docket No. ER09-1158, and Potomac Electric Power Company ("PEPCO") in Docket No. ER09-1159 (the filings referred to in (i) and (ii) above are collectively referred to as the "Filings").

Background

In its Order dated October 22, 2003 (BPU Docket No. EO03050394), 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 Agreements ("SMAs"). Furthermore, by subsequent Orders, the BPU has approved Section 15.9 of the Supplier Master Agreements ("SMA") filed by the EDCs, which authorize the EDCs to increase or decrease the rates paid to suppliers for FERC-approved rates and changes to Firm Transmission Service once approved by the Board.

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

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

Request for Board Approval

The EDCs request Board approval to implement revised BGS-FP and BGS-CIEP tariff rates effective September 1, 2013. In support of this request, the EDCs have included pro-forma tariff sheets shown in Attachment 1. The proposed BGS tariff rates have been modified in accordance with the Board-approved methodology contained in each EDC's Company-Specific Addendum in the above-referenced BGS proceedings and in conformance with each EDC's Board-approved

[1] The EDCs pay suppliers subject to the conditions of the Board-approved Supplier Master Agreements

BGS tariff sheets. The attached pro-forma tariff sheets propose an effective date of September 1, 2013 and will remain in effect until changed. The BGS-FP and BGS-CIEP rates included in the amended tariff sheets for each EDC are revised to reflect costs effective on June 1, 2013 for TECs resulting from all of the FERC-approved Filings, except the AEP-East filing which is effective on July 1, 2013.

Attachment 2 shows the cost impact for the 2013/2014 period for each of the EDCs. These costs were allocated to the various transmission zones using the cost information from the formula rates for the projects covered by the Filings, as posted on the PJM website. The translation of the transmission zone rate impact to the BGS rates of each of the EDCs assuming implementation on September 1, 2013 is included as Attachment 3. Copies of the Filings and all formula rate updates are included as Attachment 4, and can also be found on the PJM website at http://www.pjm.com/markets-and-operations/transmission-service/formula-rates.aspx.

The EDCs also request that the BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the updates from formula rates effective June 1 and July 1, 2013. Suppliers will be compensated subject to the terms and conditions of the applicable SMAs. Any differences between payments to BGS-FP and BGS-CIEP Suppliers and charges to customers will flow through BGS Reconciliation Charges. This treatment is consistent with the previously-approved mechanisms.

This filing satisfies the requirements of ¶¶ 15.9 (a)(i) and (ii) of the BGS-FP and BGS- CIEP SMAs, which mandate that BGS-FP 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,

Original signed by
Mally Becker, Esq.

Attachments

cc: Jerry May, NJBPU
Alice Bator, NJBPU
Frank Perrotti, NJBPU
Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
Service List (Electronic)

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

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Eugene Meehan NERA 1255 23rd Street Suite 600 Washington, DC 20037	Chantale LaCasse NERA 1166 Avenue of the Americas, 29th Floor New York, NY 10036	Charlene Foltzer Manager - BGS PSE&G 80 Park Plaza, T-8 P.O. Box 570 Newark, NJ 07101

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

OTHER		
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Frank Cernosek Reliant Energy 1000 Main Street REP 11-235 Houston, TX 77002	Elizabeth Sager VP – Asst. General Counsel J.P. Morgan Chase Bank, N.A. 270 Park Avenue, Floor 41 New York, NY 10017-2014	Commodity Confirmations J.P. Morgan Ventures Energy 1 Chase Manhattan Plaza 14th Floor New York, NY 10005
Manager - Contracts Admin. Sempra Energy Trading Corp. 58 Commerce Road Stamford, CT 06902	Raymond DePillo PSEG ER&T 80 Park Plaza, T-19 P.O. Box 570 Newark, NJ 07101	Sylvia Dooley Consolidated Edison of NY 4 Irving Place Room 1810-S New York, NY 10003
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Michael S. Freeman Exelon Generation Company 300 Exelon Way Kennett Square, PA 19348	Marjorie Garbini Conectiv Energy Supply, Inc. 500 North Wakefield Drive P.O. Box 6066 Newark, DE 19714-6066	Arland H. Gifford DTE Energy Trading 414 South Main Street Suite 200 Ann Arbor, MI 48104
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket No. ________________

OTHER		
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Kim M. Durham Citigroup Energy Inc. 2800 Post Oak Boulevard Suite 500 Houston, TX 77056		

Attachment 1A

Public Service Electric and Gas Company Tariff Sheets

Attachment 1B

Jersey Central Power and Light Tariff Sheets

Attachment 1C

Rockland Electric Company Tariff Sheets

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

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

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

BGS ENERGY CHARGES:

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

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	$0.106973	$0.114461	$0.105710	$0.113110
RS – in excess of 600 kWh	0.106973	0.114461	0.114269	0.122268
RHS – first 600 kWh	0.087352	0.093467	0.085130	0.091089
RHS – in excess of 600 kWh	0.087352	0.093467	0.096574	0.103334
RLM On-Peak	0.163877	0.175348	0.172465	0.184538
RLM Off-Peak	0.057230	0.061236	0.052745	0.056437
WH	0.063155	0.067576	0.063129	0.067548
WHS	0.056769	0.060743	0.057990	0.062049
HS	0.089458	0.095720	0.093805	0.100371
BPL	0.055047	0.058900	0.050774	0.054328
BPL-POF	0.055047	0.058900	0.050774	0.054328
PSAL	0.055047	0.058900	0.050774	0.054328

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.

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
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 ....$ 5.8309
Charge including New Jersey Sales and Use Tax (SUT) ....$ 6.2391

Charge applicable in the months of October through May...$ 5.8309
Charge including New Jersey Sales and Use Tax (SUT) ....$ 6.2391

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 ....$ 42,285.83 per MW per year
PJM Seams Elimination Cost Assignment Charges..................................$ 0.00 per MW per month
PJM Reliability Must Run Charge...$ 0.00 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ 91.95 per MW per month
Virginia Electric and Power Company ....$ 45.73 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....$ 10.72 per MW per month
PPL Electric Utilities Corporation...$ 25.16 per MW per month
American Electric Power Service Corporation ....$ 2.77 per MW per month
Atlantic City Electric Company. ....$ 4.97 per MW per month
Delmarva Power and Light Company...$ 5.75 per MW per month
Potomac Electric Power Company. ....$ 12.06 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months...$ 3.7231
Charge including New Jersey Sales and Use Tax (SUT) ....$ 3.9837

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

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

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 42,285.83 per MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 91.95 per MW per month
Virginia Electric and Power Company	$ 45.73 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 10.72 per MW per month
PPL Electric Utilities Corporation	$ 25.16 per MW per month
American Electric Power Service Corporation	$ 2.77 per MW per month
Atlantic City Electric Company.	$ 4.97 per MW per month
Delmarva Power and Light Company	$ 5.75 per MW per month
Potomac Electric Power Company.	$ 12.06 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 3.7231
Charge including New Jersey Sales and Use Tax (SUT)	$ 3.9837

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

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

Rider BGS-FP
Basic Generation Service – Fixed Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL)

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL. Effective January 1, 2013, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective September 1, 2013, a TRAILCO4-TEC surcharge of **$0.000423** per KWH (includes Sales and Use Tax as provided in Rider SUT), a PEPCO2-TEC surcharge of **$0.000054** per KWH (includes Sales and Use Tax as provided in Rider SUT), an ACE2-TEC surcharge of **$0.000079** per KWH (includes Sales and Use Tax as provided in Rider SUT), a Delmarva2-TEC surcharge of **$0.000025** per KWH (includes Sales and Use Tax as provided in Rider SUT), an AEP-East2-TEC surcharge of **$0.000012** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PPL2-TEC surcharge of **$0.000109** 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 except lighting under Service Classifications OL, SVL, MVL and ISL.

Effective February 1, 2013, a PATH3-TEC surcharge of **$0.000047** per KWH (includes Sales and Use Tax as provided in Rider SUT), a VEPCO3-TEC surcharge of **$0.000200** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PSEG2-TEC surcharge of **$0.001366** 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 except lighting under Service Classifications OL, SVL, MVL and ISL.

3) BGS Reconciliation Charge per KWH: ($0.002796) (includes Sales and Use Tax as provided in Rider SUT)

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

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

3) BGS Transmission Charge per KWH: (Continued)

Effective September 1, 2013, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	TRAILCO4-TEC	PEPCO2-TEC	ACE2-TEC
GT – High Tension Service	**$0.000047**	**$0.000006**	**$0.000009**
GT	**$0.000233**	**$0.000030**	**$0.000044**
GP	**$0.000266**	**$0.000034**	**$0.000050**
GS and GST	**$0.000423**	**$0.000054**	**$0.000079**

	Delmarva2-TEC	AEP-East2-TEC	PPL2-TEC
GT – High Tension Service	**$0.000003**	**$0.000001**	**$0.000012**
GT	**$0.000014**	**$0.000006**	**$0.000060**
GP	**$0.000016**	**$0.000007**	**$0.000068**
GS and GST	**$0.000025**	**$0.000012**	**$0.000109**

Effective February 1, 2013, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	PATH3-TEC	VEPCO3-TEC	PSEG2-TEC
GT – High Tension Service	**$0.000005**	**$0.000022**	**$0.000153**
GT	**$0.000026**	**$0.000111**	**$0.000758**
GP	**$0.000030**	**$0.000126**	**$0.000866**
GS and GST	**$0.000047**	**$0.000200**	**$0.001366**

4) BGS Reconciliation Charge per KWH: ($0.000384) (includes Sales and Use Tax as provided in Rider SUT)

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

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges (Continued)

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

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.323 ¢ per kWh	0.323 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.328 ¢ per kWh	0.328 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Regional Greenhouse Gas Initiative Surcharge

In accordance with General Information Section 34, a Regional Greenhouse Gas Initiative Surcharge shall be assessed on all kWh delivered hereunder.

(6) Securitization Charges

In accordance with General Information Section 35, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(7) Smart Grid Surcharge

In accordance with General Information Section 36, a Smart Grid Surcharge shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

	Summer Months*	Other Months
Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday ......@	0.811 ¢ per kWh	0.811 ¢ per kWh
Off-Peak All other kWh ......@	0.811 ¢ per kWh	0.811 ¢ per kWh

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

All kWh .....@	0.342 ¢ per kWh	0.342 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Regional Greenhouse Gas Initiative Surcharge

In accordance with General Information Section 34, a Regional Greenhouse Gas Initiative Surcharge shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

	Summer Months*	Other Months
First 250 kWh ... @	0.794 ¢ per kWh	0.794 ¢ per kWh
Next 450 kWh ... @	0.794 ¢ per kWh	0.794 ¢ per kWh
Over 700 kWh ... @	0.794 ¢ per kWh	0.794 ¢ per kWh

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

All kWh ... @	0.348 ¢ per kWh	0.348 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Regional Greenhouse Gas Initiative Surcharge

In accordance with General Information Section 34, a Regional Greenhouse Gas Initiative Surcharge shall be assessed on all kWh delivered hereunder.

(6) Securitization Charges

In accordance with General Information Section 35, the Securitization Charges shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$1.92 per kW	$1.92 per kW
Period II	All kW @	0.50 per kW	0.50 per kW
Period III	All kW @	1.74 per kW	1.74 per kW
Period IV	All kW @	0.50 per kW	0.50 per kW
Usage Charge			
Period I	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period II	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period III	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh
Period IV	All kWh @	0.366 ¢ per kWh	0.366 ¢ per kWh

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

		Primary	High Voltage Distribution
All Periods	All kWh @	0.233 ¢ per kWh	0.233 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 33, a Societal Benefits Charge 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 2.610 ¢ per kWh during the billing months of October through May and 4.125 ¢ per kWh during the summer billing months and a Transmission Charge of 0.552 ¢ per kWh and a Transmission Surcharge of 0.233 ¢ per kWh during all billing months.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.96 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), (6), (7), (8) and (9) of RATE – MONTHLY. This Special Provision is not available to those customers taking high voltage distribution service.

(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 2A

Cost Allocation of 2010/2011 TrailCo Schedule 12 Charges

Attachment 2B

Cost Allocation of 2010/2011 Delmarva Schedule 12 Charges

Attachment 2C

Cost Allocation of 2010/2011 ACE Schedule 12 Charges

Attachment 2D

Cost Allocation of 2010/2011 PEPCo Schedule 12 Charges

Attachment 2E

Cost Allocation of 2010/2011 PPL Schedule 12 Charges

Attachment 2F

Cost Allocation of 2010/2011 AEP-East Schedule 12 Charges

Please note that PJM has implemented section based formatting for the PJM Open Access Transmission Tariff which is reflected in Attachment 2 herein. PJM no longer provides individual page original sheet numbers and update information.

PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) June 2013- May 2014 Annual Revenue Requirement *per PJM website*	(b) ACE Zone Share[1]	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1]	(f) ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
			Responsible Customers - Schedule 12 Appendix *per PJM Open Access Transmission Tariff*				Estimated New Jersey EDC Zone Charges by Project				
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 165,386,156.31	1.74%	3.85%	6.47%	0.26%	$2,877,719	$6,367,367	$10,700,484	$430,004	$20,375,574
Wylie Ridge [2]	b0218	$ 3,206,525.70	11.62%	15.28%	0.00%	0.00%	$372,598	$489,957	$0	$0	$862,555
Black Oak	b0216	$ 6,547,507.53	1.74%	3.85%	6.47%	0.26%	$113,927	$252,079	$423,624	$17,024	$806,653
Meadowbrook 200 MVAR capacitor	b0559	$ 865,898.31	1.74%	3.85%	6.47%	0.26%	$15,067	$33,337	$56,024	$2,251	$106,679
Replace Kammer 765/500 kV TXfmr	b0495	$ 5,267,019.93	1.74%	3.85%	6.47%	0.26%	$91,646	$202,780	$340,776	$13,694	$648,897
Doubs TXfmr 2	b0343	$ 710,767.19	1.85%	0.00%	0.00%	0.00%	$13,149	$0	$0	$0	$13,149
Doubs TXfmr 3	b0344	$ 702,462.08	1.86%	0.00%	0.00%	0.00%	$13,066	$0	$0	$0	$13,066
Doubs TXfmr 4	b0345	$ 778,665.04	1.85%	0.00%	0.00%	0.00%	$14,405	$0	$0	$0	$14,405
New Osage 138KV Ckt	b0674-b1023.3	$ 462,363.91	0.00%	0.00%	0.25%	0.01%	$0	$0	$1,156	$46	$1,202
Cap at Grover 230	b0556	$ 12,210.80	8.58%	18.16%	26.13%	0.97%	$1,048	$2,217	$3,191	$118	$6,574
Upgrade transformer 500/230	b1153	$ 131,609.82	3.72%	12.52%	20.44%	0.71%	$4,896	$16,478	$26,901	$934	$49,209
New Osage 138 Ckt new 502 Junction	b0674-b1023.1	$ 106,057.89	0.00%	0.00%	0.25%	0.01%	$0	$0	$265	$11	$276
							$3,517,521	**$7,364,216**	**$11,552,421**	**$464,083**	**$22,898,240**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 12/13	(l) 2013TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2013 Impact (7 months)	(o) 2014 Impact (5 months)	(p) 2013-2014 Impact (12 months)
PSE&G	$ 962,701.72	10,469.8	$ 91.95	$ 6,738,912	$ 4,813,509	$ 11,552,421
JCP&L	$ 613,684.63	6,219.4	$ 98.67	$ 4,295,792	$ 3,068,423	$ 7,364,216
ACE	$ 293,126.72	2,809.0	$ 104.35	$ 2,051,887	$ 1,465,634	$ 3,517,521
RE	$ 38,673.57	429.5	$ 90.04	$ 270,715	$ 193,368	$ 464,083
Total Impact on NJ Zones	**$ 1,908,186.64**			**$ 13,357,307**	**$ 9,540,933**	**$ 22,898,240**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2013 allocation share percentages are from PJM OATT issued 5/9/2013
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2014, however resultant customer rates will not be changed.

Attachment 2A

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0216	Install -100/+525 MVAR dynamic reactive device at Black Oak	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0218	Install third Wylie Ridge 500/345kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (11.62%) / ConEd (1.79%) / DPL (19.05%) / Dominion (13.56%) / JCPL (15.28%) / PECO (38.70%)
b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7		AEC (11.62%) / ConEd (1.79%) / DPL (19.05%) / Dominion (13.56%) / JCPL (15.28%) / PECO (38.70%)
b0229	Install fourth Bedington 500/138 kV		APS (50.98%) / BGE (13.42%) / DPL (2.03%) / Dominion (14.50%) / ME (1.43%) / PEPCO (17.64%)
b0230	Install fourth Meadowbrook 500/138 kV	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (79.16%) / BGE (3.61%) / DPL (0.86%) / Dominion (11.75%) / ME (0.67%) / PEPCO (3.95%)

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

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

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

* Neptune Regional Transmission System, LLC

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

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0322	Convert Lime Kiln substation to 230 kV operation		APS (100%)
b0323	Replace the North Shenandoah 138/115 kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (100%)
b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0343	Replace Doubs 500/230 kV transformer #2	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.91%) / Dominion (28.86%) / ME (2.97%) / PECO (5.73%) / PEPCO (35.19%)
b0344	Replace Doubs 500/230 kV transformer #3	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.86%) / BGE (21.50%) / DPL (3.91%) / Dominion (28.82%) / ME (2.97%) / PECO (5.74%) / PEPCO (35.20%)
b0345	Replace Doubs 500/230 kV transformer #4	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.90%) / Dominion (28.83%) / ME (2.98%) / PECO (5.75%) / PEPCO (35.20%)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.3	Build new 502 Junction 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.6	Upgrade (per ABB inspection) breaker HL-6		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.17	Replace Meadow Brook 138 kV breaker 'MD-10'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.18	Replace Meadow Brook 138 kV breaker 'MD-11'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.19	Replace Meadow Brook 138 kV breaker 'MD-12'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.20	Replace Meadow Brook 138 kV breaker 'MD-13'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.21	Replace Meadow Brook 138 kV breaker 'MD-14'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.22	Replace Meadow Brook 138 kV breaker 'MD-15'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.23	Replace Meadow Brook 138 kV breaker 'MD-16'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.24	Replace Meadow Brook 138 kV breaker 'MD-17'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.25	Replace Meadow Brook 138 kV breaker 'MD-18'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.26	Replace Meadow Brook 138 kV breaker 'MD-22#1 CAP'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.27	Replace Meadow Brook 138 kV breaker 'MD-4'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / *ConEd (0.56%) /* Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.28	Replace Meadow Brook 138 kV breaker 'MD-5'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.29	Replace Meadowbrook 138 kV breaker 'MD-6'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.30	Replace Meadowbrook 138 kV breaker 'MD-7'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.31	Replace Meadowbrook 138 kV breaker 'MD-8'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0347.32	Replace Meadowbrook 138 kV breaker 'MD-9'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.33	Replace Meadow Brook 138kV breaker ‘MD-1’		APS (100%)
b0347.34	Replace Meadow Brook 138kV breaker ‘MD-2’		APS (100%)
b0348	Upgrade Stonewall – Inwood 138 kV with 954 ACSR conductor		APS (100%)
b0373	Convert Doubs – Monocacy 138 kV facilities to 230 kV operation		AEC (1.82%) / APS (76.84%) / DPL (2.64%) / JCPL (4.53%) / ME (9.15%) / Neptune* (0.42%) / PPL (4.60%)
b0393	Replace terminal equipment at Harrison 500 kV and Belmont 500 kV		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%)* / DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0406.1	Replace Mitchell 138 kV breaker “#4 bank”		APS (100%)
b0406.2	Replace Mitchell 138 kV breaker “#5 bank”		APS (100%)
b0406.3	Replace Mitchell 138 kV breaker “#2 transf”		APS (100%)
b0406.4	Replace Mitchell 138 kV breaker “#3 bank”		APS (100%)
b0406.5	Replace Mitchell 138 kV breaker “Charlerio #2”		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0406.6	Replace Mitchell 138 kV breaker "Charlerio #1"		APS (100%)
b0406.7	Replace Mitchell 138 kV breaker "Shepler Hill Jct"		APS (100%)
b0406.8	Replace Mitchell 138 kV breaker "Union Jct"		APS (100%)
b0406.9	Replace Mitchell 138 kV breaker "#1-2 138 kV bus tie"		APS (100%)
b0407.1	Replace Marlowe 138 kV breaker "#1 transf"		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0407.2	Replace Marlowe 138 kV breaker "MBO"		APS (100%)
b0407.3	Replace Marlowe 138 kV breaker "BMA"		APS (100%)
b0407.4	Replace Marlowe 138 kV breaker "BMR"		APS (100%)
b0407.5	Replace Marlowe 138 kV breaker "WC-1"		APS (100%)
b0407.6	Replace Marlowe 138 kV breaker "R11"		APS (100%)
b0407.7	Replace Marlowe 138 kV breaker "W"		APS (100%)
b0407.8	Replace Marlowe 138 kV breaker "138 kV bus tie"		APS (100%)
b0408.1	Replace Trissler 138 kV breaker "Belmont 604"		APS (100%)
b0408.2	Replace Trissler 138 kV breaker "Edgelawn 90"		APS (100%)
b0409.1	Replace Weirton 138 kV breaker "Wylie Ridge 210"		APS (100%)
b0409.2	Replace Weirton 138 kV breaker "Wylie Ridge 216"		APS (100%)
b0410	Replace Glen Falls 138 kV breaker "McAlpin 30"		APS (100%)
b0417	Reconductor Mitchell – Shepler Hill Junction 138kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0418	Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0420	Operating Procedure to open the Black Oak 500/138 kV transformer #3 for the loss of Hatfield – Ronco 500 kV and the Hatfield #3 Generation		APS (100%)
b0445	Upgrade substation equipment and reconductor the Tidd – Mahans Lane – Weirton 138kV circuit with 954 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0533	Reconductor the Powell Mountain – Sutton 138 kV line		APS (100%)
b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV		APS (100%)
b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV		APS (100%)
b0536	Replace Doubs circuit breaker DJ1		APS (100%)
b0537	Replace Doubs circuit breaker DJ7		APS (100%)
b0538	Replace Doubs circuit breaker DJ10		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0572.2	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0573	Reconfigure circuits in Butler – Cabot 138 kV area		APS (100%)
b0577	Replace Fort Martin 500 kV breaker FL-1		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0584	Install 33 MVAR 138 kV capacitor at Necessity 138 kV		APS (100%)
b0585	Increase Cecil 138 kV capacitor size to 44 MVAR, replace five 138 kV breakers at Cecil due to increased short circuit fault duty as a result of the addition of the Prexy substation		APS (100%)
b0586	Increase Whiteley 138 kV capacitor size to 44 MVAR		APS (100%)
b0587	Reconductor AP portion of Tidd – Carnegie 138 kV and Carnegie – Weirton 138 kV with 954 ACSR		APS (100%)
b0588	Install a 40.8 MVAR 138 kV capacitor at Grassy Falls		APS (100%)
b0589	Replace five 138 kV breakers at Cecil		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0590	Replace #1 and #2 breakers at Charleroi 138 kV		APS (100%)
b0591	Install a 25.2 MVAR capacitor at Seneca Caverns 138 kV		APS (100%)
b0673	Rebuild Elko – Carbon Center Junction using 230 kV construction		APS (100%)
b0674	Construct new Osage – Whiteley 138 kV circuit		APS (97.68%) / DL (0.96%) / PENELEC (1.09%) / ECP** (0.01%) / PSEG (0.25%) / RE (0.01%)
b0674.1	Replace the Osage 138 kV breaker ‘CollinsF126’		APS (100%)
b0675.1	Convert Monocacy - Walkersville 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.5	Convert portion of Ringgold Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.6	Convert Catoctin Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.7	Convert portion of Carroll Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.8	Convert Monocacy Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.9	Convert Walkersville Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV		AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)
b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV		AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)
b0677	Reconductor Double Toll Gate – Riverton with 954 ACSR		APS (100%)
b0678	Reconductor Glen Falls - Oak Mound 138kV with 954 ACSR		APS (100%)
b0679	Reconductor Grand Point – Letterkenny with 954 ACSR		APS (100%)
b0680	Reconductor Greene – Letterkenny with 954 ACSR		APS (100%)
b0681	Replace 600/5 CT's at Franklin 138 kV		APS (100%)
b0682	Replace 600/5 CT's at Whiteley 138 kV		APS (100%)
b0684	Reconductor Guilford – South Chambersburg with 954 ACSR		APS (100%)
b0685	Replace Ringgold 230/138 kV #3 with larger transformer		APS (71.93%) / JCPL (4.17%) / ME (6.79%) / NEPTUNE* (0.38%) / PECO (4.05%) / PENELEC (5.88%) / ECP** (0.18%) / PSEG (6.37%) / RE (0.25%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0704	Install a third Cabot 500/138 kV transformer		APS (74.36%) / DL (2.73%) PENELEC (22.91%)
b0797	Advance n0321 (Replace Doubs Circuit Breaker DJ2)		APS(100%)
b0798	Advance n0322 (Replace Doubs Circuit Breaker DJ3)		APS(100%)
b0799	Advance n0323 (Replace Doubs Circuit Breaker DJ6)		APS(100%)
b0800	Advance n0327 (Replace Doubs Circuit Breaker DJ16)		APS(100%)
b0941	Replace Opequon 138 kV breaker 'BUSTIE'		APS(100%)
b0942	Replace Butler 138 kV breaker '#1 BANK'		APS(100%)
b0943	Replace Butler 138 kV breaker '#2 BANK'		APS(100%)
b0944	Replace Yukon 138 kV breaker 'Y-8'		APS(100%)
b0945	Replace Yukon 138 kV breaker 'Y-3'		APS(100%)
b0946	Replace Yukon 138 kV breaker 'Y-1'		APS(100%)
b0947	Replace Yukon 138 kV breaker 'Y-5'		APS(100%)
b0948	Replace Yukon 138 kV breaker 'Y-2'		APS(100%)
b0949	Replace Yukon 138 kV breaker 'Y-19'		APS(100%)

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)
b0950	Replace Yukon 138 kV breaker 'Y-4'		APS(100%)
b0951	Replace Yukon 138 kV breaker 'Y-9'		APS(100%)
b0952	Replace Yukon 138 kV breaker 'Y-11'		APS(100%)
b0953	Replace Yukon 138 kV breaker 'Y-13'		APS(100%)
b0954	Replace Charleroi 138 kV breaker '#1 XFMR BANK'		APS(100%)
b0955	Replace Yukon 138 kV breaker 'Y-7'		APS(100%)
b0956	Replace Pruntytown 138 kV breaker 'P-9'		APS(100%)
b0957	Replace Pruntytown 138 kV breaker 'P-12'		APS(100%)
b0958	Replace Pruntytown 138 kV breaker 'P-15'		APS(100%)
b0959	Replace Charleroi 138 kV breaker '#2 XFMR BANK'		APS(100%)
b0960	Replace Pruntytown 138 kV breaker 'P-2'		APS(100%)
b0961	Replace Pruntytown 138 kV breaker 'P-5'		APS(100%)
b0962	Replace Yukon 138 kV breaker 'Y-18'		APS(100%)

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)
b0963	Replace Yukon 138 kV breaker 'Y-10'		APS(100%)
b0964	Replace Pruntytown 138 kV breaker 'P-11'		APS(100%)
b0965	Replace Springdale 138 kV breaker '138E'		APS(100%)
b0966	Replace Pruntytown 138 kV breaker 'P-8'		APS(100%)
b0967	Replace Pruntytown 138 kV breaker 'P-14'		APS(100%)
b0968	Replace Ringgold 138 kV breaker '#3 XFMR BANK'		APS(100%)
b0969	Replace Springdale 138 kV breaker '138C'		APS(100%)
b0970	Replace Rivesville 138 kV breaker '#8 XFMR BANK'		APS(100%)
b0971	Replace Springdale 138 kV breaker '138F'		APS(100%)
b0972	Replace Belmont 138 kV breaker 'B-16'		APS(100%)
b0973	Replace Springdale 138 kV breaker '138G'		APS(100%)
b0974	Replace Springdale 138 kV breaker '138V'		APS(100%)
b0975	Replace Armstrong 138 kV breaker 'BROOKVILLE'		APS(100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0976	Replace Springdale 138 kV breaker '138P'		APS(100%)
b0977	Replace Belmont 138 kV breaker 'B-17'		APS(100%)
b0978	Replace Springdale 138 kV breaker '138U'		APS(100%)
b0979	Replace Springdale 138 kV breaker '138D'		APS(100%)
b0980	Replace Springdale 138 kV breaker '138R'		APS(100%)
b0981	Replace Yukon 138 kV breaker 'Y-12'		APS(100%)
b0982	Replace Yukon 138 kV breaker 'Y-17'		APS(100%)
b0983	Replace Yukon 138 kV breaker 'Y-14'		APS(100%)
b0984	Replace Rivesville 138 kV breaker '#10 XFMR BANK'		APS(100%)
b0985	Replace Belmont 138 kV breaker 'B-14'		APS(100%)
b0986	Replace Armstrong 138 kV breaker 'RESERVE BUS'		APS(100%)
b0987	Replace Yukon 138 kV breaker 'Y-16'		APS(100%)
b0988	Replace Springdale 138 kV breaker '138T'		APS(100%)

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)
b0989	Replace Edgelawn 138 kV breaker 'GOFF RUN #632'		APS(100%)
b0990	Change reclosing on Cabot 138 kV breaker 'C-9'		APS(100%)
b0991	Change reclosing on Belmont 138 kV breaker 'B-7'		APS(100%)
b0992	Change reclosing on Belmont 138 kV breaker 'B-12'		APS(100%)
b0993	Change reclosing on Belmont 138 kV breaker 'B-9'		APS(100%)
b0994	Change reclosing on Belmont 138 kV breaker 'B-19'		APS(100%)
b0995	Change reclosing on Belmont 138 kV breaker 'B-21'		APS(100%)
b0996	Change reclosing on Willow Island 138 kV breaker 'FAIRVIEW #84'		APS(100%)
b0997	Change reclosing on Cabot 138 kV breaker 'C-4'		APS(100%)
b0998	Change reclosing on Cabot 138 kV breaker 'C-1'		APS(100%)
b0999	Replace Redbud 138 kV breaker 'BUS TIE'		APS(100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1022.1	Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park		APS (96.98%) / DL (3.02%)
b1022.3	Add static capacitors at Smith 138 kV		APS (96.98%) / DL (3.02%)
b1022.4	Add static capacitors at North Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.5	Add static capacitors at South Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.6	Add static capacitors at Manifold 138 kV		APS (96.98%) / DL (3.02%)
b1022.7	Add static capacitors at Houston 138 kV		APS (96.98%) / DL (3.02%)
b1023.1	Install a 500/138 kV transformer at 502 Junction		APS (100%)
b1023.2	Construct a new Franklin - 502 Junction 138 kV line including a rebuild of the Whiteley - Franklin 138 kV line to double circuit		APS (100%)
b1023.3	Construct a new 502 Junction - Osage 138 kV line		APS (100%)
b1023.4	Construct Braddock 138 kV breaker station that connects the Charleroi - Gordon 138 kV line, Washington - Franklin 138 kV line and the Washington - Vanceville 138 kV line including a 66 MVAR capacitor		APS (100%)
b1027	Increase the size of the shunt capacitors at Enon 138 kV		APS (100%)
b1028	Raise three structures on the Osage - Collins Ferry 138 kV line to increase the line rating		APS (100%)

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)
b1128	Reconductor the Edgewater – Vasco Tap; Edgewater – Loyalhanna 138 kV lines with 954 ACSR		APS (100%)
b1129	Reconductor the East Waynesboro – Ringgold 138 kV line with 954 ACSR		APS (100%)
b1131	Upgrade Double Tollgate – Meadowbrook MDT Terminal Equipment		APS (100%)
b1132	Upgrade Double Tollgate-Meadowbrook MBG terminal equipment		APS (100%)
b1133	Upgrade terminal equipment at Springdale		APS (100%)
b1135	Reconductor the Bartonville – Meadowbrook 138 kV line with high temperature conductor		APS (100%)
b1137	Reconductor the Eastgate – Luxor 138 kV; Eastgate – Sony 138 kV line with 954 ACSR		APS (78.59%) / PENELEC (14.08%) / ECP ** (0.23%) / PSEG (6.83%) / RE (0.27%)
b1138	Reconductor the King Farm – Sony 138 kV line with 954 ACSR		APS (100%)
b1139	Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor		APS (100%)
b1140	Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR		APS (100%)
b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor		APS (100%)
b1142	Reconductor the Bartonsville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR		APS (100%)
b1143	Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor		APS (89.92%) / PENELEC (10.08%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1144	Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor		APS (100%)
b1145	Reconductor the Lawson Junction – Cabot 138 kV line with high temperature conductor		APS (100%)
b1146	Replace Layton - Smithton #61 138 kV line structures to increase line rating		APS (100%)
b1147	Replace Smith – Yukon 138 kV line structures to increase line rating		APS (100%)
b1148	Reconductor the Loyalhanna – Luxor 138 kV line with 954 ACSR		APS (100%)
b1149	Reconductor the Luxor – Stony Springs Junction 138 kV line with 954 ACSR		APS (100%)
b1150	Upgrade terminal equipment at Social Hall		APS (100%)
b1151	Reconductor the Greenwood – Redbud 138 kV line with 954 ACSR		APS (100%)
b1152	Reconductor Grand Point – South Chambersburg		APS (100%)
b1159	Replace Peters 138 kV breaker 'Bethel P OCB'		APS (100%)
b1160	Replace Peters 138 kV breaker 'Cecil OCB'		APS (100%)
b1161	Replace Peters 138 kV breaker 'Union JctOCB'		APS (100%)
b1162	Replace Double Toll Gate 138 kV breaker 'DRB-2'		APS (100%)
b1163	Replace Double Toll Gate 138 kV breaker 'DT 138 kV OCB'		APS (100%)
b1164	Replace Cecil 138 kV breaker 'Enlow OCB'		APS (100%)
b1165	Replace Cecil 138 kV breaker 'South Fayette'		APS (100%)
b1166	Replace Wylie Ridge 138 kV breaker 'W-9'		APS (100%)
b1167	Replace Reid 138 kV breaker 'RI-2'		APS (100%)

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)

b1171.1	Install the second Black Oak 500/138 kV transformer, two 138 kV breaker, and related substation work		BGE (20.76%) / DPL (3.14%) / Dominion (39.55%) / ME (2.71%) / PECO (3.36%) / PEPCO (30.48%)
b1171.3	Install six 500 kV breakers and remove BOL1 500 kV breaker at Black Oak		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1200	Reconductor Double Toll Gate – Greenwood 138 kV with 954 ACSR conductor		APS (100%)
b1221.1	Convert Carbon Center from 138 kV to a 230 kV ring bus		APS (100%)
b1221.2	Construct Bear Run 230 kV substation with 230/138 kV transformer		APS (100%)
b1221.3	Loop Carbon Center Junction – Williamette line into Bear Run		APS (100%)
b1221.4	Carbon Center – Carbon Center Junction & Carbon Center Junction – Bear Run conversion from 138 kV to 230 kV		APS (100%)
b1230	Reconductor Willow-Eureka & Eurkea-St Mary 138 kV lines		APS (100%)
b1232	Reconductor Nipetown – Reid 138 kV with 1033 ACCR		AEC (1.40%) / APS (75.74%) / DPL (1.92%) / JCPL (2.92%) / ME (6.10%) / Neptune (0.27%) / PECO (4.40%) / PENELEC (3.26%) / PPL (3.99%)
b1233.1	Upgrade terminal equipment at Washington		APS (100%)
b1234	Replace structures between Ridgeway and Paper city		APS (100%)

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)
b1235	Reconductor the Albright – Black Oak AFA 138 kV line with 795 ACSS/TW		APS (30.25%) / BGE (16.10%) / Dominion (30.51%) / PEPCO (23.14%)
b1237	Upgrade terminal equipment at Albright, replace bus and line side breaker disconnects and leads, replace breaker risers, upgrade RTU and line		APS (100%)
b1238	Install a 138 kV 44 MVAR capacitor at Edgelawn substation		APS (100%)
b1239	Install a 138 kV 44 MVAR capacitor at Ridgeway substation		APS (100%)
b1240	Install a 138 kV 44 MVAR capacitor at Elko Substation		APS (100%)
b1241	Upgrade terminal equipment at Washington substation on the GE Plastics/DuPont terminal		APS (100%)
b1242	Replace structures between Collins Ferry and West Run		APS (100%)
b1243	Install a 138 kV capacitor at Potter Substation		APS (100%)
b1261	Replace Butler 138 kV breaker '1-2 BUS 138'		APS (100%)
b1383	Install 2nd 500/138 kV transformer at 502 Junction		APS (93.27%) / DL (5.39%) / PENELEC (1.34%)
b1384	Reconductor approximately 2.17 miles of Bedington – Shepherdstown 138 kV with 954 ACSR		APS (100%)
b1385	Reconductor Halfway – Paramount 138 kV with 1033 ACCR		APS (100%)
b1386	Reconductor Double Tollgate – Meadow Brook 138 kV ckt 2 with 1033 ACCR		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1387	Reconductor Double Tollgate – Meadow Brook 138 kV		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1388	Reconductor Feagans Mill – Millville 138 kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1389	Reconductor Bens Run – St. Mary's 138 kV with 954 ACSR		AEP (12.40%) / APS (17.80%) / DL (69.80%)
b1390	Replace Bus Tie Breaker at Opequon		APS (100%)
b1391	Replace Line Trap at Gore		APS (100%)
b1392	Replace structure on Belmont – Trissler 138 kV line		APS (100%)
b1393	Replace structures Kingwood – Pruntytown 138 kV line		APS (100%)
b1395	Upgrade Terminal Equipment at Kittanning		APS (100%)
b1401	Change reclosing on Pruntytown 138 kV breaker 'P-16' to 1 shot at 15 seconds		APS (100%)
b1402	Change reclosing on Rivesville 138 kV breaker 'Pruntytown #34' to 1 shot at 15 seconds		APS (100%)
b1403	Change reclosing on Yukon 138 kV breaker 'Y21 Shepler' to 1 shot at 15 seconds		APS (100%)
b1404	Replace the Kiski Valley 138 kV breaker 'Vandergrift' with a 40 kA breaker		APS (100%)
b1405	Change reclosing on Armstrong 138 kV breaker 'GARETTRJCT' at 1 shot at 15 seconds		APS (100%)
b1406	Change reclosing on Armstrong 138 kV breaker 'KITTANNING' to 1 shot at 15 seconds		APS (100%)
b1407	Change reclosing on Armstrong 138 kV breaker 'BURMA' to 1 shot at 15 seconds		APS (100%)
b1408	Replace the Weirton 138 kV breaker 'Tidd 224' with a 40 kA breaker		APS (100%)
b1409	Replace the Cabot 138 kV breaker 'C9 Kiski Valley' with a 40 kA breaker		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1507.2	Terminal Equipment upgrade at Doubs substation		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1507.3	Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1510	Install 59.4 MVAR capacitor at Waverly		APS (100%)
b1672	Install a 230 kV breaker at Carbon Center		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0539	Replace Doubs circuit breaker DJ11		APS (100%)
b0540	Replace Doubs circuit breaker DJ12		APS (100%)
b0541	Replace Doubs circuit breaker DJ13		APS (100%)
b0542	Replace Doubs circuit breaker DJ20		APS (100%)
b0543	Replace Doubs circuit breaker DJ21		APS (100%)
b0544	Remove instantaneous reclose from Eastalco circuit breaker D-26		APS (100%)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1803	Build a 300 MVAR Switched Shunt at Doubs 500 kV and increase (~50 MVAR) in size the existing Switched Shunt at Doubs 500 kV		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1804	Install a new 600 MVAR SVC at Meadowbrook 500kV		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1816.1	Replace relaying at the Mt. Airy substation on the Carroll - Mt. Airy 230 kV line		APS (100%)
b1816.2	Adjust the control settings of all existing capacitors at Mt Airy 34.5kV, Monocacy 138kV, Ringgold 138kV served by Potomac Edison's Eastern 230 kV network to ensure that all units will be on during the identified N-1-1 contingencies		APS (100%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1816.3	Replace existing unidirectional LTC controller on the No. 4, 230/138 kV transformer at Carroll substation with a bidirectional unit		APS (100%)
b1816.4	Isolate and bypass the 138 kV reactor at Germantown Substation		APS (100%)
b1816.6	Replace 336.4 ACSR conductor on the Catoctin - Carroll 138 kV line using 556.5 ACSR (26/7) or equivalent on existing structures (12.7 miles), 800 A wave traps at Carroll and Catoctin with 1200 A units, and 556.5 ACSR SCCIR (Sub-conductor) line risers and bus traps with 795 ACSR or equivalent		APS (100%)
b1822	Replace the 1200 A wave trap, line risers, breaker risers with 1600 A capacity terminal equipment at Reid 138 kV SS		APS (100%)
b1823	Replace the 800 A wave trap with a 1200 A wave trap at Millville 138 kV substation		APS (100%)
b1824	Reconductor Grant Point - Guilford 138kV line approximately 8 miles of 556 ACSR with 795 ACSR		APS (100%)
b1825	Replace the 800 Amp line trap at Butler 138 kV Sub on the Cabot East 138 kV line		APS (100%)
b1826	Change the CT ratio at Double Toll Gate 138 kV SS on MDT line		APS (100%)
b1827	Change the CT ratio at Double Toll Gate 138 kV SS on MBG line		APS (100%)
b1828.1	Reconductor the Bartonville – Stephenson 3.03 mile 138 kV line of 556 ACSR with 795 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1828.2	Reconductor the Stonewall – Stephenson 2.08 mile 138 kV line of 556 ACSR with 795 ACSR		APS (100%)
b1829	Replace the existing 138 kV 556.5 ACSR substation conductor risers with 954 ACSR at the Redbud 138 kV substation, including but not limited to the line side disconnect leads		APS (100%)
b1830	Replace 1200 A wave trap and 1024 ACAR breaker risers at Halfway 138 kV substation, and replace 1024 ACAR breaker risers at Paramount 138 kV substation		APS (100%)
b1832	Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 1 (207) 230 kV line terminal		APS (100%)
b1833	Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 2 (231) 230 kV line terminal		APS (100%)
b1835	Reconductor 14.3 miles of 556 ACSR with 795 ACSR from Old Chapel to Millville 138 kV and upgrade line risers at Old Chapel 138 kV and Millville 138 kV and replace 1200 A wave trap at Millville 138 kV		APS (37.68%) / Dominion (34.46%) / PEPCO (13.69%) / BGE (11.45%) / ME (2.01%) / PENELEC (0.53%) / DL (0.18%)
b1836	Replace 1200 A wave trap with 1600 A wave trap at Reid 138 kV SS		APS (100%)

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)
b1837	Replace 750 CU breaker risers with 795 ACSR at Marlowe 138 kV and replace 1200 A wave traps with 1600 A wave traps at Marlowe 138 kV and Bedington 138 kV		APS (100%)
b1838	Replace the 1200 A Bedington 138 kV line air switch and the 1200 A 138 kV bus tie air switch at Nipetown 138 kV with 1600 A switches		APS (100%)
b1839	Install additional 33 MVAR capacitors at Grand Point 138 kV SS and Guildford 138 kV SS		APS (100%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1840	Construct a 138 kV line between Buckhannon and Weston 138 kV substations		APS (100%)
b1902	Replace line trap at Stonewall on the Stephenson 138 kV line terminal		APS (100%)
b1941	Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong		APS (67.86%) / PENELEC (32.14%)
b1942	Change the CT ratio at Millville to improve the Millville – Old Chapel 138 kV line ratings		APS (100%)
b1964	Convert Moshannon substation to a 4 breaker 230 kV ring bus		APS (41.06%) / DPL (6.68%) / JCPL (5.48%) / ME (10.70%) / Neptune* (0.53%) / PECO (15.53%) / PPL (20.02%)
b1965	Install a 44 MVAR 138 kV capacitor at Luxor substation		APS (100%)
b1986	Upgrade the AP portion of the Elrama – Mitchell 138 kV line by replace breaker risers on the Mitchell 138 kV bus on the Elrama terminal		APS (100%)
b1987	Reconductor the Osage-Collins Ferry 138 kV line with 795 ACSS. Upgrade terminal equipment at Osage and Collins Ferry		APS (100%)
b1988	Raise structures between Lake Lynn and West Run to eliminate the clearance de-rates on the West Run – Lake Lynn 138 kV line		APS (100%)
b1989	Raise structures between Collins Ferry and West Run to eliminate the clearance de-rates on the Collins Ferry - West Run 138 kV line		APS (100%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2095	Replace Weirt 138 kV breaker 'S-TORONTO226' with 63kA rated breaker		APS (100%)
b2096	Revise the reclosing of Weirt 138 kV breaker '2&5 XFMR'		APS (100%)
b2097	Replace Ridgeley 138 kV breaker '#2 XFMR OCB'		APS (100%)
b2098	Revise the reclosing of Ridgeley 138 kV breaker 'AR3' with 40kA rated breaker		APS (100%)
b2099	Revise the reclosing of Ridgeley 138 kV breaker 'RC1'		APS (100%)
b2100	Replace Ridgeley 138 kV breaker 'WC4' with 40kA rated breaker		APS (100%)
b2101	Replace Ridgeley 138 kV breaker '1 XFMR OCB' with 40kA rated breaker		APS (100%)
b2102	Replace Armstrong 138 kV breaker 'GARETTRJCT' with 40kA rated breaker		APS (100%)
b2103	Replace Armstrong 138 kV breaker 'BURMA' with 40kA rated breaker		APS (100%)
b2104	Replace Armstrong 138 kV breaker 'KITTANNING' with 40kA rated breaker		APS (100%)
b2105	Replace Armstrong 138 kV breaker 'KISSINGERJCT' with 40kA rated breaker		APS (100%)
b2106	Replace Wylie Ridge 345 kV breaker 'WK-1' with 63kA rated breaker		APS (100%)
b2107	Replace Wylie Ridge 345 kV breaker 'WK-2' with 63kA rated breaker		APS (100%)
b2108	Replace Wylie Ridge 345 kV breaker 'WK-3' with 63kA rated breaker		APS (100%)
b2109	Replace Wylie Ridge 345 kV breaker 'WK-4' with 63kA rated breaker		APS (100%)
b2110	Replace Wylie Ridge 345 kV breaker 'WK-6' with 63kA rated breaker		APS (100%)

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)
b2111	Replace Wylie Ridge 138 kV breaker 'WK-7' with 63kA rated breaker		APS (100%)
b2112	Replace Wylie Ridge 345 kV breaker 'WK-5'		APS (100%)
b2113	Replace Weirton 138 kV breaker 'NO 6 XFMR' with 63kA rated breaker		APS (100%)
b2114	Replace Armstrong 138 kV breaker 'Bus-Tie' (Status On-Hold pending retirement)		APS (100%)
b2124.1	Add a new 138 kV line exit		APS (100%)
b2124.2	Construct a 138 kV ring bus and install a 138/69 kV autotransformer		APS (100%)
b2124.3	Add new 138 kV line exit and install a 138/25 kV transformer		APS (100%)
b2124.4	Construct approximately 5.5 miles of 138 kV line		APS (100%)
b2124.5	Convert approximately 7.5 miles of 69 kV to 138 kV		APS (100%)
b2156	Install a 75 MVAR 230 kV capacitor at Shingletown Substation		APS (100%)
b2165	Replace 800A wave trap at Stonewall with a 1200 A wave trap		APS (100%)
b2166	Reconductor the Millville – Sleepy Hollow 138kV 4.25 miles of 556 ACSR with 795 ACSR, upgrade line risers at Sleepy Hollow, and change 1200 A CT tap at Millville to 800		APS (100%)
b2168	For Grassy Falls 138kV Capacitor bank adjust turn-on voltage to 1.0pu with a high limit of 1.04pu, For Crupperneck and Powell Mountain 138kV Capacitor Banks adjust turn-on voltage to 1.01pu with a high limit of 1.035pu		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

Effective Date: 4/4/2013 - Docket #: ER13-703-000

PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for Delmarva Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2013 - May 2014 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 500 kV MAPP TX line - Delmarva portion	b0512	$ 10,333,871.61	1.74%	3.85%	6.47%	0.26%	$179,809	$397,854	$668,601	$26,868	$1,273,133
Replace line trap-Keeney	b0272.1	$ 34,197.73	1.74%	3.85%	6.47%	0.26%	$595	$1,317	$2,213	$89	$4,213
Add two breakers-Keeney	b0751	$ 794,217.25	1.74%	3.85%	6.47%	0.26%	$13,819	$30,577	$51,386	$2,065	$97,848
Totals							**$194,224**	**$429,748**	**$722,200**	**$29,022**	**$1,375,194**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 12/13**	**2013TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2013 Impact (7 months)**	**2014 Impact (5 months)**	**2013-2014 Impact (12 months)**
PSE&G	$ 60,183.33	10,469.8	$ 5.75	$ 421,283	$ 300,917	$ 722,200
JCP&L	$ 35,812.34	6,219.4	$ 5.76	$ 250,686	$ 179,062	$ 429,748
ACE	$ 16,185.32	2,809.0	$ 5.76	$ 113,297	$ 80,927	$ 194,224
RE	$ 2,418.50	429.5	$ 5.63	$ 16,929	$ 12,092	$ 29,022
Total Impact on NJ Zones	**$ 114,599.48**			**$ 802,196**	**$ 572,997**	**$ 1,375,194**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2013 allocation share percentages are from PJM OATT issued 5/9/2013
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2014, however resultant customer rates will not be changed.

Attachment 2B

SCHEDULE 12 – APPENDIX

(3) Delmarva Power & Light Company

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0262	Reconductor 0.5 miles of Christiana – Edgemoor 138 kV		DPL (100%)
b0263	Replace 1200 Amp wavetrap at Indian River on the Indian River – Frankford 138 kV line		DPL (100%)
b0272.1	Replace line trap and disconnect switch at Keeney 500 kV substation – 5025 Line Terminal Upgrade		AEC (1.74%) / AEP (14.42%) / APS (5.27%) / ATSI (8.36%) / BGE (4.33%) / ComEd (14.59%) / ConEd (0.56%) / Dayton (2.16%) / DEOK (3.37%) / DL (1.89%) / DPL (2.54%) / Dominion (11.90%) / JCPL (3.85%) / ME (1.88%) / NEPTUNE* (0.41%) / PECO (5.29%) / PENELEC (1.80%) / PEPCO (4.16%) / PPL (4.56%) / PSEG (6.47%) / RE (0.26%) / ECP** (0.19%)†
b0282	Install 46 MVAR capacitors on the DPL distribution system		DPL (100%)
b0291	Replace 1600A disconnect switch at Harmony 230 kV and for the Harmony – Edgemoor 230 kV circuit, increase the operating temperature of the conductor		DPL (100%)
b0295	Raise conductor temperature of North Seaford – Pine Street – Dupont Seaford		DPL (100%)
b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade		DPL (100%)
b0320	Create a new 230 kV station that splits the 2nd Milford to Indian River 230 kV line, add a 230/69 kV transformer, and run a new 69 kV line down to Harbeson 69 kV		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0382	Cambridge Sub – Close through to Todd Substation		DPL (100%)
b0383	Wye Mills AT-1 and AT-2 138/69 kV Replacements		DPL (100%)
b0384	Replace Indian River AT-20 (400 MVA)		DPL (100%)
b0385	Oak Hall to New Church (13765) Upgrade		DPL (100%)
b0386	Cheswold/Kent (6768) Rebuild		DPL (100%)
b0387	N. Seaford – Add a 2nd 138/69 kV autotransformer		DPL (100%)
b0388	Hallwood/Parksley (6790-2) Upgrade		DPL (100%)
b0389	Indian River AT-1 and AT-2 138/69 kV Replacements		DPL (100%)
b0390	Rehoboth/Lewes (6751-1 and 6751-2) Upgrade		DPL (100%)
b0391	Kent/New Meredith (6704-2) Upgrade		DPL (100%)
b0392	East New Market Sub – Establish a 69 kV Bus Arrangement		DPL (100%)
b0415	Increase the temperature ratings of the Edgemoor – Christiana – New Castle 138 kV by replacing six transmission poles		DPL (100%)
b0437	Spare Keeney 500/230 kV transformer		DPL (100%)
b0441	Additional spare Keeney 500/230 kV transformer		DPL (100%)
b0480	Rebuild Lank – Five Points 69 kV		DPL (100%)
b0481	Replace wave trap at Indian River 138 kV on the Omar – Indian River 138 kV circuit		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0482	Rebuild Millsboro – Zoar REA 69 kV		DPL (100%)
b0483	Replace Church 138/69 kV transformer and add two breakers		DPL (100%)
b0483.1	Build Oak Hall – Wattsville 138 kV line		DPL (100%)
b0483.2	Add 138/69 kV transformer at Wattsville		DPL (100%)
b0483.3	Establish 138 kV bus position at Oak Hall		DPL (100%)
b0484	Re-tension Worcester – Berlin 69 kV for 125ºC		DPL (100%)
b0485	Re-tension Taylor – North Seaford 69 kV for 125ºC		DPL (100%)
b0494.1	Install a 2nd Red Lion 230/138 kV		DPL (100%)
b0494.2	Hares Corner – Relay Improvement		DPL (100%)
b0494.3	Reybold – Relay Improvement		DPL (100%)
b0494.4	New Castle – Relay Improvement		DPL (100%)
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 (1.74%) / AEP (14.42%) / APS (5.27%) / ATSI (8.36%) / BGE (4.33%) / ComEd (14.59%) / ConEd (0.56%) / Dayton (2.16%) / DEOK (3.37%) / DL (1.89%) / DPL (2.54%) / Dominion (11.90%) / JCPL (3.85%) / ME (1.88%) / NEPTUNE* (0.41%) / PECO (5.29%) / PENELEC (1.80%) / PEPCO (4.16%) / PPL (4.56%) / PSEG (6.47%) / RE (0.26%) / ECP** (0.19%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0513	Rebuild the Ocean Bay – Maridel 69 kV line		DPL (100%)
b0527	Replace existing 12 MVAR capacitor at Bethany with a 30 MVAR capacitor		DPL (100%)
b0528	Replace existing 69/12 kV transformer at Bethany with a 138/12 kV transformer		DPL (100%)
b0529	Install an additional 8.4 MVAR capacitor at Grasonville 69 Kv		DPL (100%)
b0530	Replace existing 12 MVAR capacitor at Wye Mills with a 30 MVAR capacitor		DPL (100%)
b0531	Create a four breaker 138 kV ring bus at Wye Mills and add a second 138/69 kV transformer		DPL (100%)
b0566	Rebuild the Trappe Tap – Todd 69 kV line		DPL (100%)
b0567	Rebuild the Mt. Pleasant – Townsend 138 kV line		DPL (100%)
b0568	Install a third Indian River 230/138 kV transformer		DPL (100%)
b0725	Add a third Steele 230/138 kV transformer		DPL (100%)
b0732	Rebuild Vaugh – Wells 69 kV		DPL (100%)
b0733	Add a second 230/138 kV transformer at Harmony		DPL (97.06%) / PECO (2.94%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0734	Rebuild Church – Steele 138 kV		DPL (100%)
b0735	Rebuild Indian River – Omar – Bethany 138 kV		DPL (100%)
b0736	Rebuild Dupont Edgemoor – Edgemoor – Silverside 69 kV		DPL (69.46%) / PECO (17.25%) / ECP** (0.27%) / PSEG (12.53%) / RE (0.49%)
b0737	Build a new Indian River – Bishop 138 kV line		DPL (100%)
b0750	Convert 138 kV network path from Vienna – Loretto – Piney - Grove to 230 kV, add 230/138 kV transformer to Loretto 230 kV		DPL (100%)
b0751	Add two additional breakers at Keeney 500 kV		AEC (1.74%) / AEP (14.42%) / APS (5.27%) / ATSI (8.36%) / BGE (4.33%) / ComEd (14.59%) / ConEd (0.56%) / Dayton (2.16%) / DEOK (3.37%) / DL (1.89%) / DPL (2.54%) / Dominion (11.90%) / JCPL (3.85%) / ME (1.88%) / NEPTUNE* (0.41%) / PECO (5.29%) / PENELEC (1.80%) / PEPCO (4.16%) / PPL (4.56%) / PSEG (6.47%) / RE (0.26%) / ECP** (0.19%)
b0752	Replace two circuit breakers to bring the emergency rating up to 348 MVA		DPL (100%)
b0753	Add a second Loretto 230/138 kV transformer		DPL (100%)
b0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line to bring the normal rating to 298 MVA and the emergency rating to 333 MVA		DPL (100%)
b0792	Reconfigure Cecil Sub into 230 and 138 kV ring buses, add a 230/138 kV transformer, and operate the 34.5 kV bus normally open		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0873	Build 2nd Glasgow-Mt Pleasant 138 kV line		DPL (100%)
b0874	Reconfigure Brandywine substation		DPL (100%)
b0876	Install 50 MVAR SVC at 138th St 138 kV		DPL (100%)
b0877	Build a 2nd Vienna-Steele 230 kV line		DPL (100%)
b0879.1	Apply a special protection scheme (load drop at Stevensville and Grasonville)		DPL (100%)
b1246	Re-build the Townsend – Church 138 kV circuit		DPL (100%)
b1247	Re-build the Glasgow – Cecil 138 kV circuit		DPL (72.06%) / PECO (27.94%)
b1248	Install two 15 MVAR capacitor at Loretto 69 kV		DPL (100%)
b1249	Reconfigure the existing Sussex 69 kV capacitor		DPL (100%)
b1603	Upgrade 19 miles conductor of the Wattsville - Signepost - Stockton - Kenney 69 kV circuit		DPL (100%)
b1604	Replace CT at Reybold 138 kV substation		DPL (100%)
b1723	Replace strand bus and disconnect switch at Glasgow 138 kV substation		DPL (100%)

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

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

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1899.1	Install new variable reactors at Indian River and Nelson 138 kV		DPL (100%)
b1899.2	Install new variable reactors at Cedar Creek 230 kV		DPL (100%)
b1899.3	Install new variable reactors at New Castle 138 kV and Easton 69 kV		DPL (100%)

Effective Date: 1/1/2013 - Docket #: ER13-673-000

PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for ACE Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2013 - May 2014 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Upgrade AE portion of Delco Tap	b0265	$ 734,525.50	88.94%	9.38%	0.00%	0.00%	$653,287	$68,898	$0	$0	$722,185
Replace Monroe 230/69 kV TXfmrs	b0276	$ 1,061,795.71	91.28%	0.00%	8.29%	0.23%	$969,207	$0	$88,023	$2,442	$1,059,672
Reconductor Union - Corson 138 kV	b0211	$ 1,813,611.28	64.81%	25.70%	6.31%	0.00%	$1,175,401	$466,098	$114,439	$0	$1,755,938
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$ 3,844,862.03	1.74%	3.85%	6.47%	0.26%	$66,901	$148,027	$248,763	$9,997	$473,687
New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$ 2,741,528.21	64.81%	25.70%	6.31%	0.00%	$1,776,784	$704,573	$172,990	$0	$2,654,348
Totals							**$4,641,581**	**$1,387,597**	**$624,215**	**$12,439**	**$6,665,831**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 12/13**	**2013TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2013 Impact (7 months)**	**2014 Impact (5 months)**	**2013-2014 Impact (12 months)**
PSE&G	$ 52,017.89	10,469.8	$ 4.97	$ 364,125	$ 260,089	$ 624,215
JCP&L	$ 115,633.04	6,219.4	$ 18.59	$ 809,431	$ 578,165	$ 1,387,597
ACE	$ 386,798.38	2,809.0	$ 137.70	$ 2,707,589	$ 1,933,992	$ 4,641,581
RE	$ 1,036.56	429.5	$ 2.41	$ 7,256	$ 5,183	$ 12,439
Total Impact on NJ Zones	**$ 555,485.89**			**$ 3,888,401**	**$ 2,777,429**	**$ 6,665,831**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2013 allocation share percentages are from PJM OATT issued 5/9/2013
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2014, however resultant customer rates will not be changed.

Attachment 2C

SCHEDULE 12 – APPENDIX

(1) Atlantic City Electric Company

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0135	Build new Cumberland – Dennis 230 kV circuit which replaces existing Cumberland – Corson 138 kV		AEC (100%)
b0136	Install Dennis 230/138 kV transformer, Dennis 150 MVAR SVC and 50 MVAR capacitor		AEC (100%)
b0137	Build new Dennis – Corson 138 kV circuit		AEC (100%)
b0138	Install Cardiff 230/138 kV transformer and a 50 MVAR capacitor at Cardiff		AEC (100%)
b0139	Build new Cardiff – Lewis 138 kV circuit		AEC (100%)
b0140	Reconductor Laurel – Woodstown 69 kV		AEC (100%)
b0141	Reconductor Monroe – North Central 69 kV		AEC (100%)
b0265	Upgrade AE portion of Delco Tap – Mickleton 230 kV circuit		AEC (88.94%) / ConEd (1.04%) / JCPL (9.38%) / Neptune* (0.64%)
b0276	Replace both Monroe 230/69 kV transformers		AEC (91.28%) / PSEG (8.29%) / RE (0.23%) / ECP** (0.20%)
b0276.1	Upgrade a strand bus at Monroe to increase the rating of transformer #2		AEC (100%)
b0277	Install a second Cumberland 230/138 kV transformer		AEC (100%)
b0281.1	Install 35 MVAR capacitor at Lake Ave 69 kV substation		AEC (100%)
b0281.2	Install 15 MVAR capacitor at Shipbottom 69 kV substation		AEC (100%)
b0281.3	Install 8 MVAR capacitors on the AE distribution system		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0142	Reconductor Landis – Minotola 138 kV		AEC (100%)
b0143	Reconductor Beckett – Paulsboro 69 kV		AEC (100%)
b0210	Install a new 500/230kV substation in AEC area. The high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*1.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)†
b0210	Install a new 500/230kV substation in AEC area, the high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.		AEC (64.81%) / ConEd (0.65%) / JCPL (25.70%) / Neptune* (2.53%) / PSEG (6.31%)††
b0211	Reconductor Union - Corson 138kV circuit		AEC (64.81%) / ConEd (0.65%) / JCPL (25.70%) / Neptune* (2.53%) / PSEG (6.31%)
b0212	Substation upgrades at Union and Corson 138kV		AEC (64.81%) / ConEd (0.65%) / JCPL (25.70%) / Neptune* (2.53%) / PSEG (6.31%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project
††Cost allocations associated with below 500 kV elements of the project

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

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0214	Install 50 MVAR capacitor at Cardiff 230kV substation		AEC (100%)
b0431	Monroe Upgrade New Freedom strand bus		AEC (100%)
b0576	Move the Monroe 230/69 kV to Mickleton		AEC (100%)
b0744	Upgrade a strand bus at Mill 138 kV		AEC (100%)
b0871	Install 35 MVAR capacitor at Motts Farm 69 kV		AEC (100%)
b1072	Modify the existing EMS load shedding scheme at Cedar to additionally sense the loss of both Cedar 230/69 kV transformers and shed load accordingly		AEC (100%)
b1127	Build a new Lincoln-Minitola 138 kV line		AEC (100%)
b1195.1	Upgrade the Corson sub T2 terminal		AEC (100%)
b1195.2	Upgrade the Corson sub T1 terminal		AEC (100%)
b1244	Install 10 MVAR capacitor at Peermont 69 kV substation		AEC (100%)
b1245	Rebuild the Newport-South Millville 69 kV line		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1250	Reconductor the Monroe – Glassboro 69 kV		AEC (100%)
b1250.1	Upgrade substation equipment at Glassboro		AEC (100%)
b1280	Sherman: Upgrade 138/69 kV transformers		AEC (100%)
b1396	Replace Lewis 138 kV breaker 'L'		AEC (100%)
b1398.5	Reconductor the existing Mickleton – Goucestr 230 kV circuit (AE portion)		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1598	Reconductor Sherman Av – Carl's Corner 69kV circuit		AEC (100%)
b1599	Replace terminal equipments at Central North 69 kV substation		AEC (100%)
b1600	Upgrade the Mill T2 138/69 kV transformer		AEC (88.83%) / JCPL (4.74%) / HTP (0.20%) / ECP** (0.22%) / PSEG (5.78%) / RE (0.23%)
b2157	Re-build 5.3 miles of the Corson - Tuckahoe 69 kV circuit		AEC (100%)

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

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

PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for PEPCO Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2013- May 2014 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 500 kV MAPP TX line - PEPCO portion	b0512	$ 15,263,452.29	1.74%	3.85%	6.47%	0.26%	$265,584	$587,643	$987,545	$39,685	$1,880,457
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 4,449,444.36	1.78%	2.67%	3.81%	0.00%	$79,200	$118,800	$169,524	$0	$367,524
Replace 230 1A breaker	b0512.7	$ 403,140.45	1.74%	3.85%	6.47%	0.26%	$7,015	$15,521	$26,083	$1,048	$49,667
Replace 230 1B breaker	b0512.8	$ 403,140.45	1.74%	3.85%	6.47%	0.26%	$7,015	$15,521	$26,083	$1,048	$49,667
Replace 230 2A breaker	b0512.9	$ 403,140.45	1.74%	3.85%	6.47%	0.26%	$7,015	$15,521	$26,083	$1,048	$49,667
Replace 230 3A breaker	b0512.12	$ 406,671.04	1.74%	3.85%	6.47%	0.26%	$7,076	$15,657	$26,312	$1,057	$50,102
Ritchie-Benning 230 lines	b0526	$ 12,066,752.10	0.77%	1.39%	2.10%	0.08%	$92,914	$167,728	$253,402	$9,653	$523,697
Totals							**$465,818**	**$936,390**	**$1,515,032**	**$53,540**	**$2,970,781**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 12/13**	**2013TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2013 Impact (7 months)**	**2014 Impact (5 months)**	**2013-2014 Impact (12 months)**
PSE&G	$ 126,252.68	10,469.8	$ 12.06	$ 883,769	$ 631,263	$ 1,515,032
JCP&L	$ 78,032.54	6,219.4	$ 12.55	$ 546,228	$ 390,163	$ 936,390
ACE	$ 38,818.18	2,809.0	$ 13.82	$ 271,727	$ 194,091	$ 465,818
RE	$ 4,461.68	429.5	$ 10.39	$ 31,232	$ 22,308	$ 53,540
Total Impact on NJ Zones	**$ 247,565.09**			**$ 1,732,956**	**$ 1,237,825**	**$ 2,970,781**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2013 allocation share percentages are from PJM OATT issued 5/9/2013
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2014, however resultant customer rates will not be changed.

Attachment 2D

SCHEDULE 12 – APPENDIX

(10) Potomac Electric Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0146	Installation of (2) new 230 kV circuit breakers at Quince Orchard substation on circuits 23028 and 23029		PEPCO (100%)
b0219	Install two new 230 kV circuits between Palmers Corner and Blue Plains		PEPCO (100%)
b0228	Upgrade Burtonsville – Sandy Springs 230 kV circuit		PEPCO (100%)
b0238.1	Modify Dickerson Station H 230 kV		PEPCO (100%)
b0251	Install 100 MVAR of 230 kV capacitors at Bells Mill		PEPCO (100%)
b0252	Install 100 MVAR of 230 kV capacitors at Bells Mill		PEPCO (100%)
b0288	Brighton Substation – add 2nd 1000 MVA 500/230 kV transformer, 2 500 kV circuit breakers and miscellaneous bus work		BGE (19.33%) / Dominion (17%) / PEPCO (63.67%)
b0319	Add a second 1000 MVA Bruches Hill 500/230 kV transformer		PEPCO (100%)
b0366	Install a 4th Ritchie 230/69 kV transformer		PEPCO (100%)
b0367.1	Reconductor circuit “23035” for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.52%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.79%) / PEPCO (52.46%) / PPL (3.23%) / PSEG (3.81%) / ECP** (0.08%)

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

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0367.2	Reconductor circuit "23033" for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.52%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.79%) / PEPCO (52.46%) / PPL (3.23%) / PSEG (3.81%) / ECP** (0.08%)
b0375	Install 0.5% reactor at Dickerson on the Pleasant View – Dickerson 230 kV circuit		AEC (1.02%) / BGE (25.42%) / DPL (2.97%) / ME (1.72%) / PECO (3.47%) / PEPCO (65.40%)
b0467.1	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.66%) / BGE (22.09%) / ConEd (0.18%) / DPL (3.69%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.53%) / PEPCO (41.78%) / PPL (2.07%)
b0478	Reconductor the four circuits from Burches Hill to Palmers Corner		APS (1.68%) / BGE (1.83%) / PEPCO (96.49%)
b0496	Replace existing 500/230 kV transformer at Brighton		APS (5.67%) / BGE (29.68%) / Dominion (10.91%) / PEPCO (53.74%)
b0499	Install third Burches Hill 500/230 kV transformer		APS (3.54%) / BGE (7.31%) / PEPCO (89.15%)
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 (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

*Neptune Regional Transmission System, LLC

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

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.7	Advance n0772 (Replace Chalk Point 230 kV breaker (1A) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.8	Advance n0773 (Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.9	Advance n0774 (Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.10	Advance n0775 (Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.11	Advance n0776 (Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.12	Advance n0777 (Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.13	Advance n0778 (Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.14	Advance n0779 (Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.15	Advance n0780 (Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.16	Advance n0781 (Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.17	Advance n0782 (Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

* Neptune Regional Transmission System, LLC
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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.18	Advance n0783 (Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.19	Advance n0784 (Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.20	Advance n0785 (Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.21	Advance n0786 (Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.22	Advance n0787 (Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.23	Advance n0788 (Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.24	Advance n0789 (Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.25	Advance n0790 (Replace Chalk Point 230 Kv breaker (1C) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.26	Advance n0791 (Replace Chalk Point 230 Kv breaker (4C) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.27	Advance n0792 (Replace Chalk Point 230 Kv breaker (5C) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.28	Advance n0793 (Replace Chalk Point 230 Kv breaker (6C) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0512.29	Advance n0794 (Replace Chalk Point 230 Kv breaker (7C) with 80 kA breaker)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0526	Build two Ritchie – Benning Station A 230 kV lines		AEC (0.77%) / BGE (16.76%) / DPL (1.22%) / JCPL (1.39%) / ME (0.59%) / Neptune* (0.13%) / PECO (2.10%) / PEPCO (74.86%) / PSEG (2.10%) / RE (0.08%)
b0561	Install 300 MVAR capacitor at Dickerson Station "D" 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0562	Install 500 MVAR capacitor at Brighton 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0637	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0638	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0639	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0640	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0641	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0642	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0643	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0644	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0645	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0646	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0647	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0648	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0649	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0701	Expand Benning 230 kV station, add a new 250 MVA 230/69 kV transformer at Benning Station ‘A’, new 115 kV Benning switching station		BGE (30.57%) / PEPCO (69.43%)
b0702	Add a second 50 MVAR 230 kV shunt reactor at the Benning 230 kV substation		PEPCO (100%)
b0720	Upgrade terminal equipment on both lines		PEPCO (100%)
b0721	Upgrade Oak Grove – Ritchie 23061 230 kV line		PEPCO (100%)
b0722	Upgrade Oak Grove – Ritchie 23058 230 kV line		PEPCO (100%)
b0723	Upgrade Oak Grove – Ritchie 23059 230 kV line		PEPCO (100%)
b0724	Upgrade Oak Grove – Ritchie 23060 230 kV line		PEPCO (100%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0730	Add slow oil circulation to the four Bells Mill Road – Bethesda 138 kV lines, add slow oil circulation to the two Buzzard Point – Southwest 138 kV lines; increasing the thermal ratings of these six lines allows for greater adjustment of the O Street phase shifters		PEPCO (100%)
b0731	Implement an SPS to automatically shed load on the 34 kV Bells Mill Road bus for this N-2 condition. The SPS will be in effect for 2013 and 2014 until a third Bells Mill 230/34 kV is placed in-service in 2015		PEPCO (100%)
b0746	Upgrade circuit for 3,000 amps using the ACCR		AEC (0.73%) / BGE (31.05%) / DPL (1.45%) / PECO (2.46%) / PEPCO (62.88%) / PPL (1.43%)
b0747	Upgrade terminal equipment on both lines: Quince Orchard - Bells Mill 230 kV (030) and (028)		PEPCO (100%)
b0802	Advance n0259 (Replace Dickerson Station H Circuit Breaker 412A)		PEPCO (100%)
b0803	Advance n0260 (Replace Dickerson Station H Circuit Breaker 42A)		PEPCO (100%)
b0804	Advance n0261 (Replace Dickerson Station H Circuit Breaker 42C)		PEPCO (100%)
b0805	Advance n0262 (Replace Dickerson Station H Circuit Breaker 43A)		PEPCO (100%)
b0806	Advance n0264 (Replace Dickerson Station H Circuit Breaker 44A)		PEPCO (100%)

Potomac Electric Power Company (cont.)

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

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0855	Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker		PEPCO (100%)
b0856	Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker		PEPCO (100%)
b0857	Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker		PEPCO (100%)
b0858	Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		PEPCO (100%)
b0859	Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker		PEPCO (100%)
b0860	Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker		PEPCO (100%)
b0861	Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker		PEPCO (100%)
b0862	Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker		PEPCO (100%)
b0863	Replace Chalk Point 230 kV breaker (1C) with 80 kA breaker		PEPCO (100%)
b1104	Replace Burtonsville 230 kV breaker ‘1C’		PEPCO (100%)
b1105	Replace Burtonsville 230 kV breaker ‘2C’		PEPCO (100%)
b1106	Replace Burtonsville 230 kV breaker ‘3C’		PEPCO (100%)
b1107	Replace Burtonsville 230 kV breaker ‘4C’		PEPCO (100%)
b1125	Convert the 138 kV line from Buzzard 138 - Ritchie 851 to a 230 kV line and Remove 230/138 kV Transformer at Ritchie and install a spare 230/138 kV transformer at Buzzard Pt		APS (4.74%) / PEPCO (95.26%)
b1126	Upgrade the 230 kV line from Buzzard 016 – Ritchie 059		APS (4.74%) / PEPCO (95.26%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1592	Reconductor the Oak Grove – Bowie 230 kV circuit and upgrade terminal equipments at Oak Grove and Bowie 230 kV substations		AEC (2.39%) / APS (3.82%) / BGE (65.72%) / DPL (4.43%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.35%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)
b1593	Reconductor the Bowie - Burtonsville 230 kV circuit and upgrade terminal equipments at Bowie and Burtonsville 230 kV substations		AEC (2.39%) / APS (3.82%) / BGE (65.72%) / DPL (4.43%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.35%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)
b1594	Reconductor the Oak Grove – Bowie 230 kV ‘23042’ circuit and upgrade terminal equipments at Oak Grove and Bowie 230 kV substations		AEC (2.38%) / APS (3.84%) / BGE (65.72%) / DPL (4.44%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.33%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)
b1595	Reconductor the Bowie – Burtonsville 230 kV ‘23042’ circuit and upgrade terminal equipments at Oak Grove and Burtonsville 230 kV substations		AEC (2.38%) / APS (3.84%) / BGE (65.72%) / DPL (4.44%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.33%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1596	Reconductor the Dickerson station "H" – Quince Orchard 230 kV '23032' circuit and upgrade terminal equipments at Dickerson station "H" and Quince Orchard 230 kV substations		AEC (0.80%) / BGE (33.68%) / DPL (2.09%) / PECO (3.07%) / PEPCO (60.36%)
b1597	Reconductor the Oak Grove - Aquasco 230 kV '23062' circuit and upgrade terminal equipments at Oak Grove and Aquasco 230 kV substations		AEC (1.44%) / BGE (48.60%) / DPL (2.52%) / PECO (5.00%) / PEPCO (42.44%)
b2008	Reconductor feeder 23032 and 23034 to high temp. conductor (10 miles)		BGE (33.05%) / DPL (1.38%) / PECO (1.35%) / PEPCO (64.22%) /
b2136	Reconductor the Morgantown - V3-017 230 kV '23086' circuit and replace terminal equipments at Morgantown		PEPCO (100%)
b2137	Reconductor the Morgantown - Talbert 230 kV '23085' circuit and replace terminal equipment at Morgantown		PEPCO (100%)
b2138	Replace terminal equipments at Hawkins 230 kV substation		PEPCO (100%)

PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for PPL Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2013- May 2014 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 500 KV Susquehana-Roseland Line	b0487	$ 42,707,756.42	1.74%	3.85%	6.47%	0.26%	$743,115	$1,644,249	$2,763,192	$111,040	$5,261,596
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 17,165.78	1.74%	3.85%	6.47%	0.26%	$299	$661	$1,111	$45	$2,115
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$ 12,309.44	1.74%	3.85%	6.47%	0.26%	$214	$474	$796	$32	$1,517
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 24,890.75	1.74%	3.85%	6.47%	0.26%	$433	$958	$1,610	$65	$3,067
New S-R additions < 500kV[2]	b0487.1	$ 1,073,479.65	0.00%	0.00%	5.13%	0.19%	$0	$0	$55,070	$2,040	$57,109
New substation and transformers Middletown	b0468	$ 5,700,203.57	0.00%	4.56%	5.95%	0.22%	$0	$259,929	$339,162	$12,540	$611,632
Totals							**$744,061**	**$1,906,271**	**$3,160,941**	**$125,762**	**$5,937,034**
		$ 49,535,806									
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 12/13**	**2013 Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2013 Impact (7 months)**	**2014 Impact (5 months)**	**2013-2014 Impact (12 months)**
PSE&G	$ 263,411.74	10,469.8	$ 25.16	$ 1,843,882	$ 1,317,059	$ 3,160,941
JCP&L	$ 158,855.92	6,219.4	$ 25.54	$ 1,111,991	$ 794,280	$ 1,906,271
ACE	$ 62,005.08	2,809.0	$ 22.07	$ 434,036	$ 310,025	$ 744,061
RE	$ 10,480.13	429.5	$ 24.40	$ 73,361	$ 52,401	$ 125,762
Total Impact on NJ Zones	**$ 494,752.87**			**$ 3,463,270**	**$ 2,473,764**	**$ 5,937,034**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2013 allocation share percentages are from PJM OATT issued 5/9/2013
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2014, however resultant customer rates will not be changed.

Attachment 2E

SCHEDULE 12 – APPENDIX

(9) PPL Electric Utilities Corporation

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0074	Rebuild 12 miles of S. Akron – Berks 230 kV to double circuit, looping Met Ed's S. Lebanon – S. Reading line into Berks; replacement of S. Reading 230 kV breaker 107252		PPL (100%)
b0171.2	Replace wavetrap at Hosensack 500kV substation to increase rating of Elroy - Hosensack 500 kV		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0172.1	Replace wave trap at Alburtis 500kV substation		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.2	Replace two wave traps at Juniata 500 kV – on the two Juniata – Airydale 500 kV		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%)* / DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0284.4	Changes at Juniata 500 kV substation		PPL (100%)
b0293.1	Replace wavetrap at the Martins Creek 230 kV bus		PPL (100%)
b0293.2	Raise the operating temperature of the 2-1590 ACSR to 140C for the Martins Creek – Portland 230 kV circuit		PPL (100%)
b0440	Spare Juniata 500/230 kV transformer		PPL (100%)
b0468	Build a new substation with two 150 MVA transformers between Dauphin and Hummelstown 230/69 kV substations by sectionalizing the Middletown Junction – New Lebanon 230 kV line		JCPL (4.55%) / Neptune* (0.37%) / PECO (1.79%) / PENELEC (0.33%) / PPL (86.63%) / ECP** (0.18%) / PSEG (5.93%) / RE (0.22%)
b0469	Install 130 MVAR capacitor at West Shore 230 kV line		PPL (100%)

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PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0487	Build new 500 kV transmission facilities from Susquehanna to Pennsylvania – New Jersey border at Bushkill		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0487.1	Install Lackawanna 500/230 kV transformer and upgrade 230 kV substation and switchyard		PENELEC (16.90%) / PPL (77.59%) / ECP** (0.19%) / PSEG (5.13%) / RE (0.19%)
b0500.1	Conastone – Otter Creek 230 kV – Reconductor approximately 17.2 miles of 795 kcmil ACSR with new 795 kcmil ACSS operated at 160 deg C		AEC (6.27%) / DPL (8.65%) / JCPL (14.54%) / ME (10.59%) / Neptune* (1.37%) / PECO (15.66%) / PPL (21.02%) / ECP** (0.57%) / PSEG (20.56%) / RE (0.77%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0558	Install 250 MVAR capacitor at Juniata 500 kV substation		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0593	Eldred – Pine Grove 69 kV line Rebuild Part 2: 8 miles		PPL (100%)
b0595	Rebuild Lackawanna – Edella 69 kV line to double circuit		PPL (100%)
b0596	Reconductor and rebuild Stanton – Providence 69 kV #1 and #2 lines with 69 kV design; approximately 8 miles total		PPL (100%)
b0597	Reconductor Suburban – Providence 69 kV #1 and resectionalize the Suburban 69 kV lines		PPL (100%)
b0598	Reconductor Suburban Taps #1 and #2 for 69 kV line portions		PPL (100%)
b0600	Tripp Park Substation: 69 kV tap off Stanton – Providence 69 kV line #3 to new substation		PPL (100%)
b0601	Jessup Substation: New 138/69 kV tap off of Peckville – Jackson 138/69 kV line		PPL (100%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0604	Add 150 MVA, 230/138/69 transformer #6 to Harwood substation		PPL (100%)
b0605	Reconductor Stanton – Old Forge 69 kV line and resectionalize the Jenkins – Scranton 69 kV #1 and #2 lines		PPL (100%)
b0606	New 138 kV tap off Monroe – Jackson 138 kV #1 line to Bartonsville substation		PPL (100%)
b0607	New 138 kV taps off Monroe – Jackson 138 kV lines to Stroudsburg substation		PPL (100%)
b0608	New 138 kV tap off Siegfried – Jackson 138 kV #2 to transformer #2 at Gilbert substation		PPL (100%)
b0610	At South Farmersville substation, a new 69 kV tap off Nazareth – Quarry #2 to transformer #2		PPL (100%)
b0612	Rebuild Siegfried – North Bethlehem portion (6.7 miles) of Siegfried – Quarry 69 kV line		PPL (100%)
b0613	East Tannersville Substation: New 138 kV tap to new substation		PPL (100%)
b0614	Elroy substation expansion and new Elroy – Hatfield 138/69 kV double circuit lines (1.9 miles)		PPL (100%)
b0615	Reconductor and rebuild 12 miles of Seidersville – Quakerstown 138/69 kV and a new 75 MVA, 230/69 kV transformer #4		PPL (100%)
b0616	New Springfield 230/69 kV substation and transmission line connections		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0620	New 138 kV line and terminal at Monroe 230/138 substation		PPL (100%)
b0621	New 138 kV line and terminal at Siegfried 230/138 kV substation and add a second circuit to Siegfried – Jackson for 8.0 miles		PPL (100%)
b0622	138 kV yard upgrades and transmission line rearrangements at Jackson 138/69 kV substation		PPL (100%)
b0623	New West Shore – Whitehill Taps 138/69 kV double circuit line (1.3 miles)		PPL (100%)
b0624	Reconductor Cumberland – Wertzville 69 kV portion (3.7 miles) of Cumberland – West Shore 69 kV line		PPL (100%)
b0625	Reconductor Mt. Allen – Rossmoyne 69 kV portions (1.6 miles) of West Shore – Cumberland #3 and #4 lines		PPL (100%)
b0627	Replace UG cable from Walnut substation to Center City Harrisburg substation for higher ampacity (0.25 miles)		PPL (100%)
b0629	Lincoln substation: 69 kV tap to convert to modified Twin A		PPL (100%)
b0630	W. Hempfield – Donegal 69 kV line: Reconductor / rebuild from Landisville Tap – Mt. Joy (2 miles)		PPL (100%)
b0631	W. Hempfield – Donegal 69 kV line: Reconductor / rebuild to double circuit from Mt. Joy – Donegal (2 miles)		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0632	Terminate new S. Manheim – Donegal 69 kV circuit into S. Manheim 69 kV #3		PPL (100%)
b0634	Rebuild S. Manheim – Fuller 69 kV portion (1.0 mile) of S. Manheim – West Hempfield 69 kV #3 line into a 69 kV double circuit		PPL (100%)
b0635	Reconductor Fuller Tap – Landisville 69 kV (4.1 miles) into a 69 kV double circuit		PPL (100%)
b0703	Berks substation modification on Berks – South Akron 230 kV line. Modification will isolate the line fault on the South Akron line and will allow Berks transformer #2 to be energized by the South Lebanon 230 kV circuit		PPL (100%)
b0705	New Derry – Millville 69 kV line		PPL (100%)
b0707	Construct Bohemia – Twin Lakes 69 kV line, install a 10.9 MVAR capacitor bank near Bohemia 69 kV substation		PPL (100%)
b0708	New 69 kV double circuit from Jackson – Lake Naomi Tap		PPL (100%)
b0709	Install new 69 kV double circuit from Carlisle – West Carlisle		PPL (100%)
b0710	Install a third 69 kV line from Reese's Tap to Hershey substation		PPL (100%)
b0711	New 69 kV that taps West Shore – Cumberland 69 kV #1 to Whitehill 69 kV substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0712	Construct a new 69 kV line between Strassburg Tap and the Millwood – Engleside 69 kV #1 line		PPL (100%)
b0713	Construct a new 138 kV double circuit line between Dillersville Tap and the West Hempfield – Prince 138 kV line		PPL (100%)
b0714	Prepare Roseville Tap for 138 kV conversion		PPL (100%)
b0715	Transfer S. Akron – S. Manheim #1 and #2 lines from the S. Akron 69 kV Yard to the S. Akron 138 kV Yard; Install switches on S. Akron – S. Manheim 138 kV #1 and #2 lines		PPL (100%)
b0716	Add a second 69 kV line from Morgantown – Twin Valley		PPL (100%)
b0717	Rebuild existing Brunner Island – West Shore 230 kV line and add a second Brunner Island – West Shore 230 kV line		PPL (100%)
b0718	SPS scheme to drop 190 MVA of 69 kV radial load at West Shore and 56 MVA of 69 kV radial load at Cumberland		PPL (100%)
b0719	SPS scheme at Jenkins substation to open the Stanton #1 and Stanton #2 230 kV circuit breakers after the second contingency		PPL (100%)
b0791	Add a fourth 230/69 kV transformer at Stanton		PENELEC (9.55%) / PPL (90.45%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements   Annual Revenue Requirement   Responsible Customer(s)

b1074	Install motor operators on the Jenkins 230 kV ‘2W’ disconnect switch and build out Jenkins Bay 3 and have MOD ‘3W’ operated as normally open		PPL (100%)
b0881	Install motor operators on Susquehanna T21 - Susquehanna 230 kV line East CB at Susquehanna 230 kV switching station		PPL (100%)
b0908	Install motor operators at South Akron 230 kV		PPL (100%)
b0909	Convert Jenkins 230 kV yard into a 3-breaker ring bus		PPL (100%)
b0910	Install a second 230 kV line between Jenkins and Stanton		PPL (100%)
b0911	Install motor operators at Frackville 230 kV		PPL (100%)
b0912	Install 2, 10.8 MVAR capacitor banks at Scranton 69 kV		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0913	Extend Cando Tap to the Harwood-Jenkins #2 69 kV line		PPL (100%)
b0914	Build a 3rd 69 kV line from Harwood to Valmont Taps		PPL (100%)
b0915	Replace Walnut-Center City 69 kV cable		PPL (100%)
b0916	Reconductor Sunbury-Dalmatia 69 kV line		PPL (100%)
b1021	Install a new (#4) 138/69 kV transformer at Wescosville		PPL (100%)
b1196	Remove the Siegfried bus tie breaker and install a new breaker on the Martins Creek 230 kV line west bay to maintain two ties between the 230 kV buses		PPL (100%)
b1201	Rebuild the Hercules Tap to Double Circuit 69 kV		PPL (100%)
b1202	Mack-Macungie Double Tap, Single Feed Arrangement		PPL (100%)
b1203	Add the 2nd Circuit to the East Palmerton-Wagners-Lake Naomi 138/69 kV Tap		PPL (100%)
b1204	New Breinigsville 230-69 kV Substation		PPL (100%)
b1205	Siegfried-East Palmerton #1 69 kV Line- Install new 69 kV LSAB, Sectionalize, and Transfer Treichlers Substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1206	Siegfried-Quarry #1 & #2 69 kV Lines- Rebuild 3.3 mi from Quarry Substation to Macada Taps		PPL (100%)
b1209	Convert Neffsville Taps from 69 kV to 138 kV Operation		PPL (100%)
b1210	Convert Roseville Taps from 69 kV to 138 kV Operation (Part 1 – operate on the 69 kV system)		PPL (100%)
b1211	Convert Roseville Taps from 69 kV to 138 kV Operation (Part 2 – operate on the 138 kV system)		PPL (100%)
b1212	New 138 kV Taps to Flory Mill 138/69 kV Substation		PPL (100%)
b1213	Convert East Petersburg Taps from 69 kV to 138 kV operation, install two 10.8 MVAR capacitor banks		PPL (100%)
b1214	Terminate South Manheim-Donegal #2 at South Manheim, Reduce South Manheim 69 kV Capacitor Bank, Resectionalize 69 kV		PPL (100%)
b1215	Reconductor and rebuild 16 miles of Peckville-Varden 69 kV line and 4 miles of Blooming Grove-Honesdale 69 kV line		PPL (100%)
b1216	Build approximately 2.5 miles of new 69 kV transmission line to provide a "double tap – single feed" connection to Kimbles 69/12 kV substation		PPL (100%)
b1217	Provide a "double tap – single feed" connection to Tafton 69/12 kV substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1524	Build a new Pocono 230/69 kV substation		PPL (100%)
b1524.1	Build approximately 14 miles new 230 kV South Pocono – North Pocono line		PPL (100%)
b1524.2	Install MOLSABs at Mt. Pocono substation		PPL (100%)
b1525	Build new West Pocono 230/69 kV Substation		PPL (100%)
b1525.1	Build approximately 14 miles new 230 kV Jenkins-West Pocono 230 kV Line		PPL (100%)
b1525.2	Install Jenkins 3E 230 kV circuit breaker		PPL (100%)
b1526	Install a new Honeybrook – Twin Valley 69/138 kV tie		PPL (100%)
b1527	Construct a new 230/69 kV North Lancaster substation. The sub will be supplied from the SAKR-BERK 230kV Line		PPL (100%)
b1527.1	Construct new 69/138 kV transmission from North Lancaster 230/69 kV sub to Brecknock and Honeybrook areas		PPL (100%)
b1528	Install Motor-Operated switches on the Wescosville-Trexlertown #1 & #2 69 kV lines at East Texas Substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1529	Add a double breaker 230 kV bay 3 at Hosensack		PPL (100%)
b1530	Replace Lock Haven 69kV ring bus with standard breaker and half design		PPL (100%)
b1532	Install new 32.4 MVAR capacitor bank at Sunbury		PPL (100%)
b1533	Rebuild Lycoming-Lock Haven #1 and Lycoming-Lock Haven #2 69kV lines		PPL (100%)
b1534	Rebuild 1.4 miles of the Sunbury-Milton 69kV		PPL (100%)
b1601	Re-configure the Breinigsville 500 kV substation with addition two 500 kV circuit breakers		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)†
b1602	Re-configure the Elimsport 230 kV substation to breaker and half scheme and install 80 MVAR capacitor		PPL (100%)
b1740	Install a 90 MVAR cap bank on the Frackville 230 kV bus #207973		PPL (100%)
b1756	Install a 3rd West Shore 230/69 kV transformer		PPL (100%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements   Annual Revenue Requirement   Responsible Customer(s)

b1757	Install a 230 kV motor-operated air-break switch on the Clinton - Elimsport 230 kV line		PPL (100%)
b1758	Rebuild 1.65 miles of Columbia - Danville 69 kV line		PPL (100%)
b1759	Install a 69 kV 16.2 MVAR Cap at Milton substation		PPL (100%)
b1760	Install motor operated devices on the existing disconnect switches that are located on each side of all four 230 kV CBs at Stanton		PPL (100%)
b1761	Build a new Paupack - North 230 kV line (Approximately 21 miles)		PPL (100%)
b1762	Replace 3.7 miles of the existing 230 kV Blooming Grove - Peckville line by building 8.4 miles of new 230 kV circuit onto the Lackawanna - Hopatcong tower-line		PPL (100%)
b1763	Re-terminate the Peckville - Jackson and the Peckville - Varden 69 kV lines from Peckville into Lackawanna		PPL (100%)
b1764	Build a new 230-69 kV substations (Paupack)		PPL (100%)
b1765	Install a 16.2 MVAR capacitor bank at Bohemia 69-12 kV substation		PPL (100%)
b1766	Reconductor/rebuild 3.3 miles of the Siegfried - Quarry #1 and #2 lines		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1767	Install 6 motor-operated disconnect switches at Quarry substation		PPL (100%)
b1788	Install a new 500 kV circuit breaker at Wescosville		PPL (100%)
b1890	Add a second 230/69 kV transformer at North Pocono (NE/Pocono Reliability Project)		PPL (100%)
b1891	Build a new 230/138 kV Yard at Lackawanna (138 kV conversion from Lackawanna to Jenkins)		PPL (100%)
b1892	Rebuild the Throop Taps for 138 kV operation (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1893	Swap the Staton - Old Forge and Stanton - Brookside 69 kV circuits at Stanton (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1894	Rebuild and re-conductor 2.5 miles of the Stanton - Avoca 69 kV line		PPL (100%)
b1895	Rebuild and re-conductor 4.9 miles of the Stanton - Providence #1 69 kV line		PPL (100%)
b1896	Install a second 230/138 kV transformer and expand the 138 kV yard at Monroe		PPL (100%)
b1897	Build a new 230/138 kV substation at Jenkins (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1898	Install a 69 kV Tie Line between Richfield and Dalmatia substations		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2004	Replace the CTs and switch in South Akron Bay 4 to increase the rating		PPL (100%)
b2005	Replace the CTs and switch in SAKR Bay 3 to increase the rating of the Millwood-South Akron 230 kV Line and of the rating in Bay 3		PPL (100%)
b2006	Install North Lancaster 500/230 kV substation (below 500 kV portion)		AEC (1.10%) / ECP** (0.37%) / HTP (0.37%) / JCPL (9.61%) / ME (19.42%) / Neptune* (0.75%) / PECO (6.01%) / PPL (50.57%) / PSEG (11.35%) / RE (0.45%)
b2006.1	Install North Lancaster 500/230 kV substation (500 kV portion)		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b2007	Install a 90 MVAR capacitor bank at the Frackville 230 kV Substation		PPL (100%)
b2158	Install 10.8 MVAR capacitor at West Carlisle 69/12 kV substation		PPL (100%)

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

PJM Schedule 12 - Transmission Enhancement Charges for July 2013 - June 2014
Calculation of costs and monthly PJM charges for AEP -East Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) July 2013 - June 2014 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix ACE Zone Share[1] *per PJM Open Access Transmission Tariff*	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1]	(f) Estimated New Jersey EDC Zone Charges by Project ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 1,014,540.00	1.74%	3.85%	6.47%	0.26%	$17,653	$39,060	$65,641	$2,638	$124,991
Rockport Reactor Bank	b1465.2	$ 1,623,168.00	1.74%	3.85%	6.47%	0.26%	$28,243	$62,492	$105,019	$4,220	$199,974
Transpose Rockport-Sullivan 765KV line	b1465.3	$ 1,301,059.00	1.74%	3.85%	6.47%	0.26%	$22,638	$50,091	$84,179	$3,383	$160,290
Switching changes Sullivan 765KV station	b1465.4	$ 1,438,660.00	1.74%	3.85%	6.47%	0.26%	$25,033	$55,388	$93,081	$3,741	$177,243
Totals							**$93,567**	**$207,031**	**$347,920**	**$13,981**	**$324,966**

Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 12/13	(l) 2013TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2013 Impact (7 months)	(o) 2014 Impact (5 months)	(p) 2013-2014 Impact (12 months)
PSE&G	$ 28,993.29	10,469.8	$ 2.77	$ 202,953	$ 144,966	$ 347,920
JCP&L	$ 17,252.58	6,219.4	$ 2.77	$ 120,768	$ 86,263	$ 207,031
ACE	$ 7,797.27	2,809.0	$ 2.78	$ 54,581	$ 38,986	$ 93,567
RE	$ 1,165.11	429.5	$ 2.71	$ 8,156	$ 5,826	$ 13,981
Total Impact on NJ Zones	**$ 55,208.25**			**$ 386,458**	**$ 276,041**	**$ 662,499**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:

1) 2013 allocation share percentages are from PJM OATT isssued 5/9/2013
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2014, however resultant customer rates will not be changed.

Attachment 2F

SCHEDULE 12 – APPENDIX

(17) AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.2	Replace Amos 138 kV breaker 'B'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0490.3	Replace Amos 138 kV breaker 'B1'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0490.4	Replace Amos 138 kV breaker 'C'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0490.5	Replace Amos 138 kV breaker 'C1'		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.6	Replace Amos 138 kV breaker ‘D’		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0490.7	Replace Amos 138 kV breaker ‘D2’		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0490.8	Replace Amos 138 kV breaker ‘E’		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b0490.9	Replace Amos 138 kV breaker ‘E2’		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0504	Add two advanced technology circuit breakers at Hanging Rock 765 kV to improve operational performance		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
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%)
b0840	String a second 138 kV circuit on the open tower position between Twin Branch and East Elkhart		AEP (100%)

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

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)
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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1034.3	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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)
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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)
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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)
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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

b1418	Perform a sag study on the Rockhill – East Lima 138 kV line to increase the emergency rating		AEP (100%)
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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

b1462	Replace relays at both South Cadiz 138 kV and Tidd 138 kV		AEP (100%)
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 (75.06%) / APS (1.25%) / BGE (1.81%) / ComEd (5.91%) / Dayton (0.86%) / DL (1.23%) / DPL (0.95%) / Dominion (3.89%) / JCPL (1.58%) / NEPTUNE (0.15%) / HTP (0.07%) / PECO (2.08%) / PEPCO (1.66%) / ECP (0.07%)** / PSEG (2.62%) / RE (0.10%)
b1465.2	Replace the 100 MVAR 765 kV shunt reactor bank on Rockport – Jefferson 765 kV line with a 300 MVAR bank at Rockport Station		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1465.3	Transpose the Rockport – Sullivan 765 kV line and the Rockport – Jefferson 765 kV line		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%)* / DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
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%)
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%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
b1495	Add an additional 765/345 kV transformer at Baker Station		AEC (0.41%) / AEP (87.22%) / BGE (1.03%) / ComEd (3.38%) / Dayton (1.23%) / DL (1.46%) / DPL (0.54%) / JCPL (0.90%) / NEPTUNE (0.09%) / HTP (0.04%) / PECO (1.18%) / PEPCO (0.94%) / ECP** (0.04%) / 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%)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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 (93.61%) / ATSI (2.99%) / ComEd (2.07%) / HTP (0.03%) / PENELEC (0.31%) / ECP** (0.03%) / PSEG (0.92%) / RE (0.04%)
b1659.1	Replace Sorenson 138 kV breaker 'L1'		AEP (100%)
b1659.2	Replace Sorenson 138 kV breaker 'L2' breaker		AEP (100%)
b1659.3	Replace Sorenson 138 kV breaker 'M1'		AEP (100%)
b1659.4	Replace Sorenson 138 kV breaker 'M2'		AEP (100%)
b1659.5	Replace Sorenson 138 kV breaker 'N1'		AEP (100%)
b1659.6	Replace Sorenson 138 kV breaker 'N2'		AEP (100%)
b1659.7	Replace Sorenson 138 kV breaker 'O1'		AEP (100%)
b1659.8	Replace Sorenson 138 kV breaker 'O2'		AEP (100%)
b1659.9	Replace Sorenson 138 kV breaker 'M'		AEP (100%)
b1659.10	Replace Sorenson 138 kV breaker 'N'		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1659.11	Replace Sorenson 138 kV breaker 'O'		AEP (100%)
b1659.12	Replace McKinley 138 kV breaker 'L1'		AEP (100%)
b1659.13	Establish 765 kV yard at Sorenson and install four 765 kV breakers		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville line		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1660	Install a 765/500 kV transformer at Cloverdale		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1661	Install a 765 kV circuit breaker at Wyoming station		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
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%)
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%)

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AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)
b1663	Install a new 765/138 kV transformer at Jackson Ferry substation		AEP (100%)
b1663.1	Establish a new 10 mile double circuit 138 kV line between Jackson Ferry and Wythe		AEP (100%)
b1663.2	Install 2 765 kV circuit breakers, breaker disconnect switches and associated bus work for the new 765 kV breakers, and new relays for the 765 kV breakers at Jackson's Ferry		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
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%)
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%)

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
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%)
b1782	Install a 46kV Moab at Montgomery Station facing Carbondale (on the London - Carbondale 46 kV circuit)		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)
b1874	Install two 138 kV circuit breakers and one 138 kV circuit switcher at Magely 138 kV station in Indiana		AEP (100%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

b1955	Perform a sag study of the R-049 - Tillman 138 kV line may improve the emergency rating to 245 MVA		AEP (100%)
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 (69.41%) / ATSI (23.11%) / ECP** (0.17%) / HTP (0.19%) / PENELEC (2.42%) / PSEG (4.52%) / 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%)
b1962	Add four 765 kV breakers at Kammer		AEC (*1.74*%) / AEP (*14.42*%) / APS (*5.27*%) / ATSI (*8.36*%) / BGE (*4.33*%) / ComEd (*14.59*%) / ConEd (*0.56*%) / Dayton (*2.16*%) / *DEOK (3.37%) /* DL (*1.89*%) / DPL (*2.54*%) / Dominion (*11.90*%) / JCPL (*3.85*%) / ME (*1.88*%) / NEPTUNE* (0.41%) / PECO (*5.29*%) / PENELEC (*1.80*%) / PEPCO (*4.16*%) / PPL (*4.56*%) / PSEG (*6.47*%) / RE (*0.26*%) / ECP** (0.19%)
b1963	Build approximately 1 mile of circuit comprising of 2-954 ACSR to get the rating of Waterford-Muskinum 345 kV higher		AEP (100%)

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

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

b1970	Reconductor 13 miles of the Kammer – West Bellaire 345kV circuit		APS (33.51%) / ATSI (32.21%) / DL (18.64%) / Dominion (6.01%) / ECP** (0.10%) / HTP (0.11%) / JCPL (1.68%) / Neptune* (0.18%) / PENELEC (4.58%) / PSEG (2.87%) / 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%)
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 (37.04%) / AEP (34.35%) / DL (10.41%) / Dominion (6.19%) / APS (3.94%) / PENELEC (3.09%) / JCPL (1.39%) / Dayton (1.20%) / Neptune* (0.14%) / HTP (0.09%) / ECP** (0.08%) / 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%)

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

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

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

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

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%)
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%)

AEP East Operating Companies (Appalachian Power Company, Columbus Southern 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)

b2160	Add a fourth circuit breaker to the station being built for the U4-038 project (Conelley), rebuild U4-038 - Grant Tap line as double circuit tower line		AEP (100%)
b2161	Rebuild approximately 20 miles of the Allen - S073 double circuit 138 kV line (with one circuit from Allen - Tillman - Timber Switch - S073 and the other circuit from Allen - T-131 - S073) utilizing 1033 ACSR		AEP (100%)
b2162	Perform a sag study to improve the emergency rating of the Belpre - Degussa 138 kV line		AEP (100%)
b2163	Replace breaker and wavetrap at Jay 138 kV station		AEP (100%)

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

Attachment 3A

Translation of 2010/2011 Schedule 12 Charges into Rates – JCP&L

Attachment 3B

Translation of 2010/2011 Schedule 12 Charges into Rates – PSE&G

Attachment 3C

Translation of 2010/2011 Schedule 12 Charges into Rates - RECO

Attachment 3a

Jersey Central Power & Light Company
Proposed PPL Project Transmission Enhancement Charge (PPL2-TEC Surcharge) effective September 1, 2013
To reflect FERC-approved PPL Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2013 - May 2014

2013/2014 Average Monthly PPL2-TEC Costs Allocated to JCP&L Zone	$	158,855.92	(1)
2013 JCP&L Zone Transmission Peak Load (MW)		6219.4	
PPL2-Transmission Enhancement Rate ($/MW-month)	$	25.54	

				Effective September 1, 2013:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PPL2-TEC Surcharge ($/kWh)	PPL2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5495.7	1,684,454	16,483,640,522	$ 0.000102	$ 0.000109
Primary	380.2	116,533	1,808,699,133	$ 0.000064	$ 0.000068
Transmission @ 34.5 kV	330.1	101,177	1,794,607,833	$ 0.000056	$ 0.000060
Transmission @ 230 kV	13.4	4,107	360,889,247	$ 0.000011	$ 0.000012
Total	6219.4	1,906,271	20,447,836,735		

(1) Cost Allocation of PPL Project Schedule 12 Charges to JCP&L Zone for 2013/2014
(2) Based on 12 months PPL Project costs from June 2013 through May 2014
(3) September 2013 through August 2014

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,675,327	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		17,316,063	MWH
3	BGS-FP Eligible Transmission Obligation		5,828	MW
4	PPL2-Transmission Enhancement Costs to FP Suppliers	$	1,786,305	= Line 3 x $25.54 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.10	= Line 4 / Line 2

Attachment 3A

Attachment 3a

Jersey Central Power & Light Company
Proposed AEP-East Project Transmission Enhancement Charge (AEP-East2-TEC Surcharge) effective September 1, 2013
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective July 2013 - June 2014

2013/2014 Average Monthly AEP-East2-TEC Costs Allocated to JCP&L Zone	$	17,252.58	(1)
2013 JCP&L Zone Transmission Peak Load (MW)		6219.4	
AEP-East2-Transmission Enhancement Rate ($/MW-month)	$	2.77	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective September 1, 2013: AEP-East2-TEC Surcharge ($/kWh)	AEP-East2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5495.7	182,940	16,483,640,522	$ 0.000011	$ 0.000012
Primary	380.2	12,656	1,808,699,133	$ 0.000007	$ 0.000007
Transmission @ 34.5 kV	330.1	10,988	1,794,607,833	$ 0.000006	$ 0.000006
Transmission @ 230 kV	13.4	446	360,889,247	$ 0.000001	$ 0.000001
Total	6219.4	207,031	20,447,836,735		

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2013/2014
(2) Based on 12 months AEP-East Project costs from July 2013 through June 2014
(3) September 2013 through August 2014

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,675,327	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		17,316,063	MWH
3	BGS-FP Eligible Transmission Obligation		5,828	MW
4	AEP-East2-Transmission Enhancement Costs to FP Suppliers	$	194,002	= Line 3 x $2.77 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.01	= Line 4 / Line 2

Attachment 3A

Attachment 3a

Jersey Central Power & Light Company
Proposed Delmarva Project Transmission Enhancement Charge (Delmarva2-TEC Surcharge) effective September 1, 2013
To reflect FERC-approved Delmarva Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2013 - May 2014

2013/2014 Average Monthly Delmarva2-TEC Costs Allocated to JCP&L Zone	$	35,812.34	(1)
2013 JCP&L Zone Transmission Peak Load (MW)		6219.4	
Delmarva2-Transmission Enhancement Rate ($/MW-month)	$	5.76	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective September 1, 2013:** Delmarva2-TEC Surcharge ($/kWh)	Delmarva2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5495.7	379,742	16,483,640,522	$ 0.000023	$ 0.000025
Primary	380.2	26,271	1,808,699,133	$ 0.000015	$ 0.000016
Transmission @ 34.5 kV	330.1	22,809	1,794,607,833	$ 0.000013	$ 0.000014
Transmission @ 230 kV	13.4	926	360,889,247	$ 0.000003	$ 0.000003
Total	6219.4	429,748	20,447,836,735		

(1) Cost Allocation of Delmarva Project Schedule 12 Charges to JCP&L Zone for 2013/2014
(2) Based on 12 months Delmarva Project costs from June 2013 through May 2014
(3) September 2013 through August 2014

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

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,675,327	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		17,316,063	MWH
3	BGS-FP Eligible Transmission Obligation		5,828	MW
4	Delmarva2-Transmission Enhancement Costs to FP Suppliers	$	402,703	= Line 3 x $5.76 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.02	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed ACE Project Transmission Enhancement Charge (ACE2-TEC Surcharge) effective September 1, 2013
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2013 - May 2014

2013/2014 Average Monthly ACE-TEC Costs Allocated to JCP&L Zone	$	115,633.04	(1)
2013 JCP&L Zone Transmission Peak Load (MW)		6219.4	
ACE2-Transmission Enhancement Rate ($/MW-month)	$	18.59	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective September 1, 2013: ACE2-TEC Surcharge ($/kWh)	ACE2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5495.7	1,226,133	16,483,640,522	$ 0.000074	$ 0.000079
Primary	380.2	84,826	1,808,699,133	$ 0.000047	$ 0.000050
Transmission @ 34.5 kV	330.1	73,648	1,794,607,833	$ 0.000041	$ 0.000044
Transmission @ 230 kV	13.4	2,990	360,889,247	$ 0.000008	$ 0.000009
Total	6219.4	1,387,596	20,447,836,735		

(1) Cost Allocation of ACE Project Schedule 12 Charges to JCP&L Zone for 2013/2014
(2) Based on 12 months ACE Project costs from June 2013 through May 2014
(3) September 2013 through August 2014

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

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,675,327	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		17,316,063	MWH
3	BGS-FP Eligible Transmission Obligation		5,828	MW
4	ACE2-Transmission Enhancement Costs to FP Suppliers	$	1,300,272	= Line 3 x $18.59 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.08	= Line 4 / Line 2

Attachment 3a

Jersey Central Power & Light Company
Proposed PEPCO Project Transmission Enhancement Charge (PEPCO2-TEC Surcharge) effective September 1, 2013
To reflect FERC-approved PEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2013 - May 2014

2013/2014 Average Monthly PEPCO2-TEC Costs Allocated to JCP&L Zone	$	78,032.54	(1)
2013 JCP&L Zone Transmission Peak Load (MW)		6219.4	
PEPCO2-Transmission Enhancement Rate ($/MW-month)	$	12.55	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective September 1, 2013: PEPCO2-TEC Surcharge ($/kWh)	PEPCO2-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5495.7	827,430	16,483,640,522	$ 0.000050	$ 0.000054
Primary	380.2	57,243	1,808,699,133	$ 0.000032	$ 0.000034
Transmission @ 34.5 kV	330.1	49,700	1,794,607,833	$ 0.000028	$ 0.000030
Transmission @ 230 kV	13.4	2,017	360,889,247	$ 0.000006	$ 0.000006
Total	6219.4	936,390	20,447,836,735		

(1) Cost Allocation of PEPCO Project Schedule 12 Charges to JCP&L Zone for 2013/2014
(2) Based on 12 months PEPCO Project costs from June 2013 through May 2014
(3) September 2013 through August 2014

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,675,327	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		17,316,063	MWH
3	BGS-FP Eligible Transmission Obligation		5,828	MW
4	PEPCO2-Transmission Enhancement Costs to FP Suppliers	$	877,461	= Line 3 x $12.55 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.05	= Line 4 / Line 2

Attachment 3A

Attachment 3a

Jersey Central Power & Light Company
Proposed TRAILCO Project Transmission Enhancement Charge (TRAILCO4-TEC Surcharge) effective September 1, 2013
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2013 - May 2014

2013/2014 Average Monthly TRAILCO4-TEC Costs Allocated to JCP&L Zone	$	613,684.63	(1)
2013 JCP&L Zone Transmission Peak Load (MW)		6219.4	
TRAILCO4-Transmission Enhancement Rate ($/MW-month)	$	98.67	

				Effective September 1, 2013:			
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)		TRAILCO4-TEC Surcharge ($/kWh)		TRAILCO4-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5495.7	6,507,303	16,483,640,522	$	0.000395	$	0.000423
Primary	380.2	450,184	1,808,699,133	$	0.000249	$	0.000266
Transmission @ 34.5 kV	330.1	390,862	1,794,607,833	$	0.000218	$	0.000233
Transmission @ 230 kV	13.4	15,867	360,889,247	$	0.000044	$	0.000047
Total	6219.4	7,364,216	20,447,836,735				

(1) Cost Allocation of TRAILCO Project Schedule 12 Charges to JCP&L Zone for 2013/2014
(2) Based on 12 months TRAILCO Project costs from June 2013 through May 2014
(3) September 2013 through August 2014

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales June through May @ Customer		15,675,327	MWH
2	BGS-FP Eligible Sales June through May @ Transmission Node		17,316,063	MWH
3	BGS-FP Eligible Transmission Obligation		5,828	MW
4	TRAILCO4-Transmission Enhancement Costs to FP Suppliers	$	6,900,770	= Line 3 x $98.67 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.40	= Line 4 / Line 2

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Project

TEC Charges for June 2013 - May 2014		$11,552,421	
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/13)		10,469.80	
Term (Months)		12	
OATT rate	$	91.95	/MW/month
Resulting Increase in Transmission Rate	$	1,103.40	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,284.7	31.6	85.0	0.0	0.0	4.6	0.0	0.0
Total Annual Energy - MWh	13,062,967	156,836	263,095	1,903	37	21,681	165,772	337,465
Change in energy charge								
in $/MWh	$ 0.3619	$ 0.2223	$ 0.3565	$ -	$ -	$ 0.2341	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000362**	**$ 0.000222**	**$ 0.000356**	**$ -**	**$ -**	**$ 0.000234**	**$ -**	**$ -**

Line #					
1	Total BGS-FP eligbile Trans Obl		8,419.6 MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		30,067,790 MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		32,218,479 MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	9,290,187	unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2883 /MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.29 /MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	9,343,359	unrounded	= (6) * (3)
8	Difference due to rounding	$	53,172	unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for ACE Project

TEC Charges for June 2013 - May 2014	$	624,215	
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/13)		10,469.80	
Term (Months)		12	
OATT rate	$	4.97	/MW/month
Resulting Increase in Transmission Rate	$	59.64	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,284.7	31.6	85.0	0.0	0.0	4.6	0.0	0.0
Total Annual Energy - MWh	13,062,967	156,836	263,095	1,903	37	21,681	165,772	337,465
Change in energy charge								
in $/MWh	$ 0.0196	$ 0.0120	$ 0.0193	$ -	$ -	$ 0.0127	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000020**	**$ 0.000012**	**$ 0.000019**	**$ -**	**$ -**	**$ 0.000013**	**$ -**	**$ -**

Line #					
1	Total BGS-FP eligbile Trans Obl		8,419.6 MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		30,067,790 MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		32,218,479 MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	502,145	unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0156 /MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.02 /MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	644,370	unrounded	= (6) * (3)
8	Difference due to rounding	$	142,225	unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for PEPCO Project

TEC Charges for June 2013 - May 2014	$	1,515,032	
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/13)		10,469.80	
Term (Months)		12	
OATT rate	$	12.06	/MW/month
Resulting Increase in Transmission Rate	$	144.72	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,284.7	31.6	85.0	0.0	0.0	4.6	0.0	0.0
Total Annual Energy - MWh	13,062,967	156,836	263,095	1,903	37	21,681	165,772	337,465
Change in energy charge								
in $/MWh	$ 0.0475	$ 0.0292	$ 0.0468	$ -	$ -	$ 0.0307	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000047**	**$ 0.000029**	**$ 0.000047**	**$ -**	**$ -**	**$ 0.000031**	**$ -**	**$ -**

Line #					
1	Total BGS-FP eligbile Trans Obl	8,419.6 MW			= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	30,067,790 MWh			= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	32,218,479 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 1,218,485		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0378	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.04	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,288,739		unrounded	= (6) * (3)
8	Difference due to rounding	$ 70,255		unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for Delmarva Project

TEC Charges for June 2013 - May 2014	$	722,200	
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/13)		10,469.80	
Term (Months)		12	
OATT rate	$	5.75	/MW/month
Resulting Increase in Transmission Rate	$	69.00	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,284.7	31.6	85.0	0.0	0.0	4.6	0.0	0.0
Total Annual Energy - MWh	13,062,967	156,836	263,095	1,903	37	21,681	165,772	337,465
Change in energy charge								
in $/MWh	$ 0.0226	$ 0.0139	$ 0.0223	$ -	$ -	$ 0.0146	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000023**	**$ 0.000014**	**$ 0.000022**	**$ -**	**$ -**	**$ 0.000015**	**$ -**	**$ -**

Line #						
1	Total BGS-FP eligbile Trans Obl		8,419.6	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		30,067,790	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		32,218,479	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	580,952		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0180	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.02	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	644,370		unrounded	= (6) * (3)
8	Difference due to rounding	$	63,417		unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2013 - May 2014
Calculation of costs and monthly PJM charges for PPL Project

TEC Charges for June 2013 - May 2014	$	3,160,941		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/13)		10,469.80		
Term (Months)		12		
OATT rate	$	25.16	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	301.92	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,284.7	31.6	85.0	0.0	0.0	4.6	0.0	0.0
Total Annual Energy - MWh	13,062,967	156,836	263,095	1,903	37	21,681	165,772	337,465
Change in energy charge								
in $/MWh	$ 0.0990	$ 0.0608	$ 0.0975	$ -	$ -	$ 0.0641	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000099**	**$ 0.000061**	**$ 0.000098**	**$ -**	**$ -**	**$ 0.000064**	**$ -**	**$ -**

Line #						
1	Total BGS-FP eligbile Trans Obl		8,419.6	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		30,067,790	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		32,218,479	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	2,542,046		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0789	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.08	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	2,577,478		unrounded	= (6) * (3)
8	Difference due to rounding	$	35,433		unrounded	= (7) - (4)

Attachment 3B

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for July 2013 - June 2014
Calculation of costs and monthly PJM charges for AEP Project

TEC Charges for July 2013 - June 2014	$	347,920	
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/13)		10,469.80	
Term (Months)		12	
OATT rate	$	2.77	/MW/month
Resulting Increase in Transmission Rate	$	33.24	/MW/yr

all values show w/o NJ SUT

		RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW		4,284.7	31.6	85.0	0.0	0.0	4.6	0.0	0.0
Total Annual Energy - MWh		13,062,967	156,836	263,095	1,903	37	21,681	165,772	337,465
Change in energy charge									
in $/MWh	$	0.0109	$ 0.0067	$ 0.0107	$ -	$ -	$ 0.0071	$ -	$ -
in $/kWh - rounded to 6 places	**$**	**0.000011**	**$ 0.000007**	**$ 0.000011**	**$ -**	**$ -**	**$ 0.000007**	**$ -**	**$ -**

Line #						
1	Total BGS-FP eligbile Trans Obl		8,419.6	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		30,067,790	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		32,218,479	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	279,868		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0087	/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	$	322,185		unrounded	= (6) * (3)
8	Difference due to rounding	$	42,317		unrounded	= (7) - (4)

Attachment 3B

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2013
To reflect FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2013 to May 2014

2013/2014 Average Monthly ACE-TEC Costs Allocated to RECO	$	1,037	(1)
2012 RECO Zone Transmission Peak Load (MW)		463.9	(2)
Transmission Enhancement Rate ($/MW-month)	$	2.23	

	Col. 1	Col. 2	Col.3=Col.2 x $1,037 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2013- Aug 2014 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	258.5	55.73%	$ 6,933	720,765,000	$ 0.00001	$ 0.00001
SC2 Secondary	124.5	26.83%	$ 3,338	546,050,000	$ 0.00001	$ 0.00001
SC2 Primary	14.1	3.03%	$ 377	86,277,000	$ -	$ -
SC3	0.1	0.01%	$ 2	268,000	$ 0.00001	$ 0.00001
SC4	0.0	0.00%	$ -	6,299,000	$ -	$ -
SC5	4.0	0.86%	$ 106	15,792,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	5,533,000	$ -	$ -
SC7	62.8	13.53%	$ 1,683	252,829,000	$ 0.00001	$ 0.00001
Total	463.9 (2)	100.00%	$ 12,439	1,633,813,000		

(1) Attachment 2 - Cost Allocation of ACE Schedule 12 Charges to RECO Zone for June 2013 through May 2014
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep - Aug @ cust (RECO Eastern Division)		1,318,386	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,231,405	MWH
3	BGS-FP Eligible Transmission Obligation		401	MW
4	Transmission Enhancement Costs to FP Suppliers	$	10,734.17	= Line 3 x $2.23 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Attachment 3C

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2013
To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2013 to June 2014

2013/2014 Average Monthly AEP-East-TEC Costs Allocated to RECO	$ 1,165	(1)
2012 RECO Zone Transmission Peak Load (MW)	463.9	(2)
Transmission Enhancement Rate ($/MW-month)	$ 2.51	

	Col. 1	Col. 2	Col.3=Col.2 x $1,165 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2013- Aug 2014 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	258.5	55.73%	$ 7,792	720,765,000	$ 0.00001	$ 0.00001
SC2 Secondary	124.5	26.83%	$ 3,752	546,050,000	$ 0.00001	$ 0.00001
SC2 Primary	14.1	3.03%	$ 424	86,277,000	$ -	$ -
SC3	0.1	0.01%	$ 2	268,000	$ 0.00001	$ 0.00001
SC4	0.0	0.00%	$ -	6,299,000	$ -	$ -
SC5	4.0	0.86%	$ 120	15,792,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	5,533,000	$ -	$ -
SC7	62.8	13.53%	$ 1,892	252,829,000	$ 0.00001	$ 0.00001
Total	463.9 (2)	100.00%	$ 13,982	1,633,813,000		

(1) Attachment 2 - Cost Allocation of AEP Schedule 12 Charges to RECO Zone for June 2013 through May 2014
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep - Aug @ cust (RECO Eastern Division)		1,318,386	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,231,405	MWH
3	BGS-FP Eligible Transmission Obligation		401	MW
4	Transmission Enhancement Costs to FP Suppliers	$	12,081.96	= Line 3 x $2.51 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Attachment 3C

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2013
To reflect FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2013 to May 2014

2013/2014 Average Monthly Delmarva-TEC Costs Allocated to RECO	$	2,418	(1)
2012 RECO Zone Transmission Peak Load (MW)		463.9	(2)
Transmission Enhancement Rate ($/MW-month)	$	5.21	

	Col. 1	Col. 2	Col.3=Col.2 x $2,418 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2013- Aug 2014 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	258.5	55.73%	$ 16,175	720,765,000	$ 0.00002	$ 0.00002
SC2 Secondary	124.5	26.83%	$ 7,788	546,050,000	$ 0.00001	$ 0.00001
SC2 Primary	14.1	3.03%	$ 880	86,277,000	$ 0.00001	$ 0.00001
SC3	0.1	0.01%	$ 4	268,000	$ 0.00001	$ 0.00001
SC4	0.0	0.00%	$ -	6,299,000	$ -	$ -
SC5	4.0	0.86%	$ 248	15,792,000	$ 0.00002	$ 0.00002
SC6	0.0	0.00%	$ -	5,533,000	$ -	$ -
SC7	62.8	13.53%	$ 3,926	252,829,000	$ 0.00002	$ 0.00002
Total	463.9 (2)	100.00%	$ 29,021	1,633,813,000		

(1) Attachment 2 - Cost Allocation of Delmarva Schedule 12 Charges to RECO Zone for June 2013 through May 2014
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep - Aug @ cust (RECO Eastern Division)		1,318,386	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,231,405	MWH
3	BGS-FP Eligible Transmission Obligation		401	MW
4	Transmission Enhancement Costs to FP Suppliers	$	25,078.50	= Line 3 x $5.21 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.02	= Line 4/Line 2

Attachment 3C

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2013
To reflect FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2013 to May 2014

2013/2014 Average Monthly PEPCO-TEC Costs Allocated to RECO	$	4,462	(1)
2012 RECO Zone Transmission Peak Load (MW)		463.9	(2)
Transmission Enhancement Rate ($/MW-month)	$	9.62	

	Col. 1	Col. 2		Col.3=Col.2 x $4,462 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2013- Aug 2014 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	258.5	55.73%	$	29,840	720,765,000	$	0.00004	$	0.00004
SC2 Secondary	124.5	26.83%	$	14,367	546,050,000	$	0.00003	$	0.00003
SC2 Primary	14.1	3.03%	$	1,624	86,277,000	$	0.00002	$	0.00002
SC3	0.1	0.01%	$	8	268,000	$	0.00003	$	0.00003
SC4	0.0	0.00%	$	-	6,299,000	$	-	$	-
SC5	4.0	0.86%	$	458	15,792,000	$	0.00003	$	0.00003
SC6	0.0	0.00%	$	-	5,533,000	$	-	$	-
SC7	62.8	13.53%	$	7,244	252,829,000	$	0.00003	$	0.00003
Total	463.9 (2)	100.00%	$	53,541	1,633,813,000				

(1) Attachment 2 - Cost Allocation of PEPCO Schedule 12 Charges to RECO Zone for June 2012 through May 2013
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep - Aug @ cust (RECO Eastern Division)		1,318,386	MWH
2	BGS-FP Eligible Sales Sep - Aug @ trans node (RECO Eastern Division)		1,231,405	MWH
3	BGS-FP Eligible Transmission Obligation		401	MW
4	Transmission Enhancement Costs to FP Suppliers	$	46,306.17	= Line 3 x $9.62 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.04	= Line 4/Line 2

Attachment 3C

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2013
To reflect FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2013 to May 2014

2013/2014 Average Monthly PPL-TEC Costs Allocated to RECO	$	10,480	(1)
2012 RECO Zone Transmission Peak Load (MW)		463.9	(2)
Transmission Enhancement Rate ($/MW-month)	$	22.59	

	Col. 1	Col. 2	Col.3=Col.2 x $10,480 x 12		Col. 4	Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07	
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)		BGS Eligible Sales Sep 2013- Aug 2014 (kWh)	Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)	
SC1	258.5	55.73%	$	70,092	720,765,000	$	0.00010	$	0.00011
SC2 Secondary	124.5	26.83%	$	33,746	546,050,000	$	0.00006	$	0.00006
SC2 Primary	14.1	3.03%	$	3,815	86,277,000	$	0.00004	$	0.00004
SC3	0.1	0.01%	$	18	268,000	$	0.00007	$	0.00007
SC4	0.0	0.00%	$	-	6,299,000	$	-	$	-
SC5	4.0	0.86%	$	1,075	15,792,000	$	0.00007	$	0.00007
SC6	0.0	0.00%	$	-	5,533,000	$	-	$	-
SC7	62.8	13.53%	$	17,015	252,829,000	$	0.00007	$	0.00007
Total	463.9 (2)	100.00%	$	125,761	1,633,813,000				

(1) Attachment 2 - Cost Allocation of PPL Schedule 12 Charges to RECO Zone for June 2012 through May 2013
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.					
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,318,386	MWH	
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,231,405	MWH	
3	BGS-FP Eligible Transmission Obligation		401	MW	
4	Transmission Enhancement Costs to FP Suppliers	$	108,737.67	= Line 3 x $22.59 * 12	
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.09	= Line 4/Line 2	

Attachment 3C

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective September 1, 2013
To reflect FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 2013 to May 2014

2013/2014 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	38,674	(1)
2012 RECO Zone Transmission Peak Load (MW)		463.9	(2)
Transmission Enhancement Rate ($/MW-month)	$	83.37	

	Col. 1	Col. 2		Col.3=Col.2 x $38,674 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales Sep 2013- Aug 2014 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	258.5	55.73%	$	258,653	720,765,000	$	0.00036	$	0.00039
SC2 Secondary	124.5	26.83%	$	124,529	546,050,000	$	0.00023	$	0.00025
SC2 Primary	14.1	3.03%	$	14,079	86,277,000	$	0.00016	$	0.00017
SC3	0.1	0.01%	$	66	268,000	$	0.00025	$	0.00027
SC4	0.0	0.00%	$	-	6,299,000	$	-	$	-
SC5	4.0	0.86%	$	3,968	15,792,000	$	0.00025	$	0.00027
SC6	0.0	0.00%	$	-	5,533,000	$	-	$	-
SC7	62.8	13.53%	$	62,787	252,829,000	$	0.00025	$	0.00027
Total	463.9 (2)	100.00%	$	464,082	1,633,813,000				

(1) Attachment 2 - Cost Allocation of TrailCo Schedule 12 Charges to RECO Zone for June 2012 through May 2013
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.					
1	BGS-FP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,318,386	MWH	
2	BGS-FP Eligible Sales Jun - May @ trans node (RECO Eastern Division)		1,231,405	MWH	
3	BGS-FP Eligible Transmission Obligation		401	MW	
4	Transmission Enhancement Costs to FP Suppliers	$	401,304.10	= Line 3 x $83.37 * 12	
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.33	= Line 4/Line 2	

Attachment 3C

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective January 1, 2013
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved 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) for 2013
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) for currently in RECO's rates
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2013
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) for 2013

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
AEP-East - TEC	(3)	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(4)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00002	0.00000	0.00002
PATH - TEC	(5)	0.00004	0.00003	0.00003	0.00003	0.00000	0.00003	0.00000	0.00002
PEPCO - TEC	(6)	0.00004	0.00003	0.00002	0.00003	0.00000	0.00003	0.00000	0.00003
PPL - TEC	(7)	0.00010	0.00006	0.00004	0.00007	0.00000	0.00007	0.00000	0.00007
PSE&G - TEC	(8)	0.00374	0.00252	0.00268	0.00267	0.00000	0.00271	0.00000	0.00169
TrAILCo - TEC	(9)	0.00036	0.00023	0.00016	0.00025	0.00000	0.00025	0.00000	0.00025
VEPCo - TEC	(10)	0.00018	0.00012	0.00013	0.00012	0.00000	0.00013	0.00000	0.00008
Total ($/kWh and excl SUT)		$0.00450	$0.00302	$0.00307	$0.00320	$0.00000	$0.00326	$0.00000	$0.00218
Total (¢/kWh and excl SUT)		0.450 ¢	0.302 ¢	0.307 ¢	0.320 ¢	0.000 ¢	0.326 ¢	0.000 ¢	0.218 ¢

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
AEP-East - TEC	(3)	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(4)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00002	0.00000	0.00002
PATH - TEC	(5)	0.00004	0.00003	0.00003	0.00003	0.00000	0.00003	0.00000	0.00002
PEPCO - TEC	(6)	0.00004	0.00003	0.00002	0.00003	0.00000	0.00003	0.00000	0.00003
PPL - TEC	(7)	0.00011	0.00006	0.00004	0.00007	0.00000	0.00007	0.00000	0.00007
PSE&G - TEC	(8)	0.00400	0.00270	0.00287	0.00286	0.00000	0.00290	0.00000	0.00181
TrAILCo - TEC	(9)	0.00039	0.00025	0.00017	0.00027	0.00000	0.00027	0.00000	0.00027
VEPCo - TEC	(10)	0.00019	0.00013	0.00014	0.00013	0.00000	0.00014	0.00000	0.00009
Total ($/kWh and incl SUT)		$0.00481	$0.00323	$0.00328	$0.00342	$0.00000	$0.00348	$0.00000	$0.00233
Total (¢/kWh and incl SUT)		0.481 ¢	0.323 ¢	0.328 ¢	0.342 ¢	0.000 ¢	0.348 ¢	0.000 ¢	0.233 ¢

Notes:

(1) RMR rates based on allocations by transmission zone. For RECO, the estimated allocation is zero percent.
(2) ACE-TEC rates calculated in Attachment 3 of the joint filing.
(3) AEP-East-TEC rates calculated in Attachment 3 of the joint filing.
(4) Delmarva-TEC rates calculated in Attachment 3 of the joint filing.
(5) PATH-TEC rates pursuant to the Board's Order dated January 23, 2013 in Docket No. ER12121086.
(6) PEPCO-TEC rates calculated in Attachment 3 of the joint filing.
(7) PPL-TEC rates calculated in Attachment 3 of the joint filing.
(8) PSE&G-TEC rates pursuant to the Board's Order dated January 23, 2013 in Docket No. ER12121086.
(9) TrAILCo-TEC rates calculated in Attachment 3 of the joint filing.
(10) VEPCo-TEC rates pursuant to the Board's Order dated January 23, 2013 in Docket No. ER12121086.

Attachment 4A

TrAILCo Formula Rate Update Compliance Filing

Attachment 4B

Delmarva Formula Rate Update Compliance Filing

Attachment 4C

ACE Formula Rate Update Compliance Filing

Attachment 4D

PEPCo Formula Rate Update Compliance Filing

Attachment 4E

PPL Formula Rate Update Compliance Filing

Attachment 4F

AEP-East Formula Rate Update Compliance Filing

ATTACHMENT H-18A

Trans-Allegheny Interstate Line Company

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	TrAILCo
	Shaded cells are input cells			**2013 Forecast**
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	102,593
2	Total Wages Expense		p354.28.b	593,074
3	Less A&G Wages Expense		p354.27.b	490,481
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	102,593
5	**Wages & Salary Allocator**		(Line 1 / Line 4), if line 2 = 0, then 100%	**100.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	1,276,556,179
7	Total Plant In Service		(Line 6)	1,276,556,179
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	61,187,355
9	Total Accumulated Depreciation		(Line 8)	61,187,355
10	Net Plant		(Line 7 - Line 9)	1,215,368,824
11	Transmission Gross Plant		(Line 15 + Line 21)	1,276,556,179
12	**Gross Plant Allocator**		(Line 11 / Line 7, if Line 7=0, enter 100%)	**100.0000%**
13	Transmission Net Plant		(Line 11 - Line 29)	1,215,368,824
14	**Net Plant Allocator**		(Line 13 / Line 10, if line 10=0, enter 100%)	**100.0000%**
	Plant Calculations			
	Transmission Plant			
15	Transmission Plant In Service	(Note B)	Attachment 5	1,209,952,076
16	New Trans. Plant Adds. for Current Calendar Year (13 average balance)	(Note B)	Attachment 6	18,686,682
17	**Total Transmission Plant**		(Line 15 + Line 16)	**1,228,638,758**
18	General & Intangible		Attachment 5	66,604,103
19	Total General & Intangible		(Line 18)	66,604,103
20	Wage & Salary Allocator		(Line 5)	100.0000%
21	**Transmission Related General and Intangible Plant**		(Line 19 * Line 20)	**66,604,103**
22	**Transmission Related Plant**		**(Line 17 + Line 21)**	**1,295,242,861**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	55,471,672
24	Accumulated General Depreciation		Attachment 5	2,554,609
25	Accumulated Intangible Amortization		Attachment 5	3,161,074
26	Total Accumulated General and Intangible Depreciation		(Sum Lines 24 to 25)	5,715,683
27	Wage & Salary Allocator		(Line 5)	100.0000%
28	**Transmission Related General & Intangible Accumulated Depreciation**		(Line 26 * Line 27)	**5,715,683**
29	**Total Transmission Related Accumulated Depreciation**		**(Line 23 + Line 28)**	**61,187,355**
30	**Total Transmission Related Net Property, Plant & Equipment**		**(Line 22 - Line 29)**	**1,234,055,506**

Adjustment To Rate Base

	Accumulated Deferred Income Taxes			
31	ADIT net of FASB 106 and 109 Enter Negative		Attachment 1	-128,293,676
32	**Transmission Related Accumulated Deferred Income Taxes**		(Line 31)	**-128,293,676**
33	**Transmission Related CWIP (Current Year 13 Month weighted average balances)**	(Note B)	p216.b.43 as shown on Attachment 6	**1,843,384**
34	**Transmission Related Land Held for Future Use**	(Note C)	Attachment 5	**0**
	Transmission Related Pre-Commercial Costs Capitalized			
35	Unamortized Capitalized Pre-Commercial Costs		Attachment 5	**0**
	Prepayments			
36	**Transmission Related Prepayments**	(Note A)	Attachment 5	**84,814**
	Materials and Supplies			
37	Undistributed Stores Expense	(Note A)	Attachment 5	0
38	Wage & Salary Allocator		(Line 5)	100.0000%
39	Total Undistributed Stores Expense Allocated to Transmission		(Line 37 * Line 38)	0
40	Transmission Materials & Supplies		Attachment 5	0
41	**Transmission Related Materials & Supplies**		(Line 39 + Line 40)	**0**
	Cash Working Capital			
42	Operation & Maintenance Expense		(Line 74)	-4,793,942
43	1/8th Rule		1/8	12.5%
44	**Transmission Related Cash Working Capital**		(Line 42 * Line 43)	**-599,243**
45	**Total Adjustment to Rate Base**		(Lines 32 + 33 + 34 + 35+ 36 + 41 + 44)	**-126,964,721**
46	**Rate Base**		(Line 30 + Line 45)	**1,107,090,785**

O&M

	Transmission O&M			
47	Transmission O&M		p321.112.b	1,380,688
48	Less Account 566 Misc Trans Exp listed on line 73 below.)		(line 73)	706,234
49	Less Account 565		p321.96.b	0
50	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note M)	PJM Data	0
51	Plus Property Under Capital Leases		p200.4.c	0
52	**Transmission O&M**		(Lines 47 - 48 - 49 + 50 + 51)	**674,454**
	A&G Expenses			
53	Total A&G		p323.197.b	-6,286,629
54	Less Property Insurance Account 924		p323.185.b	36,356
55	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	0
56	Less General Advertising Exp Account 930.1		p323.191.b	9
57	Less PBOP Adjustment		Attachment 5	-112,008
58	Less EPRI Dues	(Note D)	p352 & 353	0
59	**A&G Expenses**		(Line 53) - Sum (Lines 54 to 58)	-6,210,986
60	Wage & Salary Allocator		(Line 5)	100.0000%
61	**Transmission Related A&G Expenses**		(Line 59 * Line 60)	**-6,210,986**
	Directly Assigned A&G			
62	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	0
63	General Advertising Exp Account 930.1	(Note J)	Attachment 5	0
64	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 62 + Line 63)	**0**
65	Property Insurance Account 924		p323.185.b	36,356
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 928 and 930.1 - General		(Line 65 + Line 66)	36,356
68	Net Plant Allocator		(Line 14)	100.0000%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**36,356**
	Account 566 Miscellaneous Transmission Expense			
70	Amortization Expense on Pre-Commercial Cost	Account 566	Attachment 5	0
71	Pre-Commercial Expense	Account 566	Attachment 5	0
72	Miscellaneous Transmission Expense	Account 566	Attachment 5	706,234
73	Total Account 566		Sum (Lines 70 to 72)	**706,234**
74	**Total Transmission O&M**		**(Lines 52 + 61 + 64 + 69 + 73)**	**-4,793,942**

Depreciation & Amortization Expense

	Depreciation Expense				
75	Transmission Depreciation Expense			Attachment 5	27,736,728
76	General Depreciation			Attachment 5	1,145,979
77	Intangible Amortization		(Note A)	Attachment 5	1,923,223
78	Total			(Line 76 + Line 77)	3,069,202
79	Wage & Salary Allocator			(Line 5)	100.0000%
80	**Transmission Related General Depreciation and Intangible Amortization**			(Line 78 * Line 79)	**3,069,202**
81	**Total Transmission Depreciation & Amortization**			**(Lines 75 + 80)**	**30,805,930**

Taxes Other than Income

82	**Transmission Related Taxes Other than Income**			Attachment 2	**7,230,515**
83	**Total Taxes Other than Income**			**(Line 82)**	**7,230,515**

Return / Capitalization Calculations

84	**Preferred Dividends**		enter positive	p118.29.c	0
	Common Stock				
85	Proprietary Capital			p112.16.c	665,442,241
86	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	0
87	Less Preferred Stock			(Line 95)	0
88	Less Account 216.1			p112.12.c	0
89	**Common Stock**			(Line 85 - 86 - 87 - 88)	665,442,241
	Capitalization				
90	Long Term Debt		(Note N)		450,000,000
91	Less Unamortized Loss on Reacquired Debt			p111.81.c	4,917,402
92	Plus Unamortized Gain on Reacquired Debt			p113.61.c	0
93	Less ADIT associated with Gain or Loss			Attachment 1	-1,940,464
94	Total Long Term Debt			(Line 90 - 91 + 92 - 93)	447,023,062
95	Preferred Stock			p112.3.c	0
96	Common Stock			(Line 89)	665,442,241
97	**Total Capitalization**			(Sum Lines 94 to 96)	1,112,465,303
98	Debt %	Total Long Term Debt	(Note N)	(Line 94 /Line 97)	40.1831%
99	Preferred %	Preferred Stock	(Note N)	(Line 95 /Line 97)	0.0000%
100	Common %	Common Stock	(Note N)	(Line 96 /Line 97)	59.8169%
101	Debt Cost	Total Long Term Debt			0.0489
102	Preferred Cost	Preferred Stock		(Line 84 / Line 95)	0.0000
103	Common Cost	Common Stock	(Note I)	The most recent FERC approved ROE	0.1170
104	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 98 * Line 101)	0.0196
105	Weighted Cost of Preferred	Preferred Stock		(Line 99 * Line 102)	0.0000
106	Weighted Cost of Common	Common Stock		(Line 100 * Line 103)	0.0700
107	**Rate of Return on Rate Base (ROR)**			(Sum Lines 104 to 106)	**0.0896**
108	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 107)**	**99,218,177**

Composite Income Taxes

	Income Tax Rates			
109	FIT=Federal Income Tax Rate	(Note H)		35.00%
110	SIT=State Income Tax Rate or Composite			7.64%
111	p	(percent of federal income tax deductible for state purp	Per State Tax Code	0.00%
112	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.97%
113	T/ (1-T)			66.57%
114	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 113 * Line 108 * (1- (Line 104 / Line 107))]	**51,581,299**
115	**Total Income Taxes**		**(Line 114)**	**51,581,299**

REVENUE REQUIREMENT

	Summary			
116	Net Property, Plant & Equipment		(Line 30)	1,234,055,506
117	Total Adjustment to Rate Base		(Line 45)	-126,964,721
118	**Rate Base**		(Line 46)	**1,107,090,785**
119	Total Transmission O&M		(Line 74)	-4,793,942
120	Total Transmission Depreciation & Amortization		(Line 81)	30,805,930
121	Taxes Other than Income		(Line 83)	7,230,515
122	Investment Return		(Line 108)	99,218,177
123	Income Taxes		(Line 115)	51,581,299
124	**Gross Revenue Requirement**		**(Sum Lines 119 to 123)**	**184,041,979**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
125	Transmission Plant In Service		(Line 22)	1,295,242,861
126	Excluded Transmission Facilities	(Note L)	Attachment 5	0
127	Included Transmission Facilities		(Line 125 - Line 126)	1,295,242,861
128	Inclusion Ratio		(Line 127 / Line 125)	100.00%
129	Gross Revenue Requirement		(Line 124)	184,041,979
130	**Adjusted Gross Revenue Requirement**		(Line 128 * Line 129)	**184,041,979**
	Revenue Credits			
131	**Revenue Credits**		Attachment 3	3,335,876
132	**Net Revenue Requirement**		**(Line 130 - Line 131)**	**180,706,103**
	Net Plant Carrying Charge			
133	Net Revenue Requirement		(Line 132)	**180,706,103**
134	Net Transmission Plant + CWIP		(Line 17 - Line 23 + Line 33)	**1,175,010,470**
135	FCR		(Line 133 / Line 134)	**15.3791%**
136	FCR without Depreciation		(Line 133 - Line 75) / Line 134	**13.0186%**
137	FCR without Depreciation and Pre-Commercial Costs		(Line 133 - Line 70 - Line 71 - Line 75) / Line 134	**13.0186%**
138	FCR without Depreciation, Return, nor Income Taxes		(Line 133 - Line 75 - Line 108 - Line 115) / Line 134	**0.1847%**
	Net Plant Carrying Charge Calculation with Incentive ROE			
139	Net Revenue Requirement Less Return and Taxes		(Line 132 - Line 122 - Line 123)	**29,906,627**
140	Increased Return and Taxes		Attachment 4	**161,830,407**
141	Net Revenue Requirement with Incentive ROE		(Line 139 + Line 140)	**191,737,035**
142	Net Transmission Plant + CWIP		(Line 17 - Line 23+ Line 33)	**1,175,010,470**
143	FCR with Incentive ROE		(Line 141 / Line 142)	**16.3179%**
144	FCR with Incentive ROE without Depreciation		(Line 141 - Line 75) / Line 142	**13.9573%**
145	FCR with Incentive ROE without Depreciation and Pre-Commercial		(Line 141 - Line 70 - Line 71 - Line 75) / Line 142	**13.9573%**
146	**Net Revenue Requirement**		(Line 132)	**180,706,103.06**
147	Reconciliation amount		Attachment 6	**-1,348,793.74**
148	Plus any increased ROE calculated on Attach 7 other than PJM Sch. 12 projects not paid by other PJM trans zones		Attachment 7	**9,895,166.08**
149	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**0.00**
150	**Net Zonal Revenue Requirement**		(Line 146 + 147 + 148 + 149)	**189,252,475.39**
	Network Zonal Service Rate			
151	1 CP Peak	(Note K)	PJM Data	**N/A**
152	Rate ($/MW-Year)		(Line 150 / 151)	**N/A**
153	**Network Service Rate ($/MW/Year)**		**(Line 152)**	**N/A**

Notes

A Electric portion only

B For both the estimate and the reconciliation, Construction Work In Progress ("CWIP") and leases that are expensed as O&M (rather than amortized) are excluded.
For the Estimate Process:
Transmission plant in service will show the end of year balance and is linked to Attachment 5 which shows detail support by project.
The transmission plant will agree to or be reconciled to the FERC Form 1 balance for the transmission plant.
New Transmission Plant expected to be placed in service in the current calendar year will be based on the average of 13 monthly investment costs and shown separately detailed by project on Attachment 6.
Accumulated depreciation will show the end of year balance and is linked to Attachment 5 which shows detail support by project.
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).
For the Reconciliation Process:
Transmission plant in service will be calculated using a 13 month average balance and will be detailed on Attachment 5. This includes new transmission plant added to plant-in-service
Accumulated depreciation will be calculated using a 13 month average balance and will be detailed on Attachment 5. This includes accumulated depreciation associated with current year transmission plant.
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

C Includes Transmission portion only and (i) only land that has an estimated in-service date within 10 years may be included and (ii) a plan for the land's use is required to be included in the filing whenever the cost of the land is proposed to be included in rates.

D Excludes all EPRI Annual Membership Dues

E Excludes 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 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.

I ROE will be established in the Commission order accepting the settlement in Docket No. ER07-562 and no change in ROE will be made absent a Section 205 or Section 206 filing at FERC.

J Education and outreach expenses relating to transmission, for example siting or billing

K 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.

L Amount of transmission plant excluded from rates per Attachment 5.

M 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 on Line 47. If they are booked to Acct 565, they are included on Line 50. Copies of PJM invoices will be provided upon request.

N The capital structure will remain 50% equity and 50% debt until construction of all of the segments of the TrAIL Project is completed and the entire TrAIL Project is placed in service. The first year that these projects are in service the formula will be run based on the 50/50 capital structure and on the actual year end capital structure. The two results will be weighted based on: the number of days the last project was in service and 365 day minus the numbers of days the last project was in service divided by 365 days.
This can be illustrated using the following example:

Example:

Assume Last Project goes into service on day 260.
Hypothetical Capital Structure until the last project goes into service is 50/50.
Assume Year End actual capital structure is 60% equity and 40% debt.

Therefore: Weighted Equity = [50%*260+60%*(365-260)]/365

Trans-Allegheny Interstate Line Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

		Trans-Allegheny Interstate Company								
Line		B1	B2	B3	C	D	E	F	G	
		Beg of Year Total	*End of Year Total*	End of Year for Est. Average for Final *Total*	Retail Related	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
1	**ADIT- 282 From Account Total Below**	266,474,684	394,680,133	330,577,408	[redacted]	394,680,133	-	-	394,680,133	
2	**ADIT-283 From Account Total Below**	42,877,660	41,190,814	42,034,237	[redacted]	41,190,814	-	-	41,190,814	
3	**ADIT-190 From Account Total Below**	(207,162,750)	(307,577,271)	(257,370,011)	[redacted]	(307,577,271)	-	-	(307,577,271)	Enter Negative
4	**Subtotal**					128,293,676	-	-	128,293,676	
5	**Wages & Salary Allocator**							100.0000%		
6	**Gross Plant Allocator**						100.0000%			
7	**ADIT**					128,293,676	-	-	128,293,676	

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 93.

Amount 1,940,464 < From Acct 283, below

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	
	Trans-Allegheny Interstate Company								
ADIT-190	Beg of Year Balance p234.18.b	End of Year Balance p234.18.c	End of Year for Est. Average for Final Total	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Tax Interest Capitalized	-	-	-			-			Actual amount of tax interest capitalized
Depreciation	-	-	-			-			Book depreciation
Taxes Intercompany Charges AESC	471,249	-	235,625			235,625			Intercompany charges from the service company
Worker's Compensation	115,163	107,796	111,480			111,480			Actual amount of reserve for workers' compensation
Long Term Disability Accrual	23,788	-	11,894			11,894			Long term disability accrual
Excess Over/Under Prior Service	-	-	-			-			Excess over under prior service cost
Amortization Expense	-	-	-			-			Amortization of intangible plant
WV Rate Change Consolidated Benefit	(111)	-	(56)			(56)			Temporary difference due to change in state tax rate in West Virginia
CIAC - Taxable	-	-	-			-			Taxable CIAC
Taxes Accrued State Other	-	-	-			-			PA Sales Tax
Miscellaneous Other Property Tax	(409,701)	-	(204,851)			(204,851)			WV Property Tax
Merger Costs Capitalized	-	-	-		-	-			Costs incurred as a result of Allegheny merging with First Energy which are not to be included within the revenue requirement
Reserve for EIB	-	-	-			-			Allocated portion of total liabilities relating to captive insurance
Power Tax Adjustment	79,364	79,377	79,371			79,371			System adjustment to reclass balances to correct FERC accounts
Operating Provision Enviro Accrual	-	-	-			-			Environmental clean-up expenses
State Income Taxes	1,387,436	1,684,577	1,536,007			1,536,007			Return/Accrual (catch up entry)
Merger Costs Licenses	95,603	98,248	96,926		96,926				Costs incurred as a result of Allegheny merging with First Energy which are not to be included within the revenue requirement
Merger Costs D&O Insurance	1,783	2,149	1,966		1,966				Costs incurred as a result of Allegheny merging with First Energy which are not to be included within the revenue requirement
Merger Costs - Indebtedness	36,879	82	18,481		18,481				Costs incurred as a result of Allegheny merging with First Energy which are not to be included within the revenue requirement
NOL	205,361,297	-	102,680,649			102,680,649			Result of bonus depreciation
Federal NOL	-	257,698,000	128,849,000			128,849,000			Result of bonus depreciation
State NOL	-	47,183,053	23,591,527			23,591,527			Result of bonus depreciation - PA, WV and MD
FASB 109 Gross-Up	-	658,656	329,328		-	329,328			Reclass of the tax portion (gross-up) for property items included in account 282
Reevaluation Adjustment	-	723,989	361,995		361,995				Temporary difference resulting from purchase accounting transations
Subtotal	207,162,750	308,235,927	257,699,339	-	479,367	257,219,972	-	-	
Less FASB 109 included above	-	658,656	329,328	-	-	329,328	-	-	
Less FASB 106 included above									
Total	207,162,750	307,577,271	257,370,011	-	479,367	256,890,644	-	-	

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.

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT- 282	**Beg of Year Balance p274.9.b**	**End of Year Balance p275.9.k**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related Related**	**Only Transmission Related Related**	**Plant Related Related**	**Labor Related Related**	**JUSTIFICATION**
Property Related - ABFUDC	1,385,924	1,471,989	1,428,957			1,428,957			Allowance for borrowed funds used during construction (ABFUDC)
Property Related - Tax Depreciation	59,177,794	52,132,953	55,655,374			55,655,374			Tax depreciation
FASB 109 Fixed Asset Adjustment	2,874,719	2,875,185	2,874,952			2,874,952			Increase in AOFDC
FASB 109 Gross-Up	-	658,656	329,328			329,328			Reclass of the tax portion (gross-up) for property items included in account 282
Book Depreciation Expense	(11,494,570)	(23,043,665)	(17,269,118)			(17,269,118)			Book depreciation
Amortization Expense - Intangible Plant	(391,037)	(1,158,152)	(774,595)			(774,595)			Book depreciation / amortization
Bonus Depreciation	248,177,294	403,045,379	325,611,337			325,611,337			Tax depreciation
CIACS Taxable	(396,922)	(1,381,132)	(889,027)			(889,027)			Taxable CIAC
Tax Interest Capitalized	(31,119,116)	(31,447,541)	(31,283,329)			(31,283,329)			Actual amount of tax interest capitalized
Power Tax Adjustment	149,056	149,080	149,068			149,068			System adjustment to reclass balances to correct FERC accounts
A&G Expenses Capitalized	(354,946)	(279,682)	(317,314)			(317,314)			Accounting change relating to A&G expense
Estimated Property Regulatory Asset Adjustment	1,341,207	1,341,207	1,341,207			1,341,207			Property True-Up
Book Profit/Loss on Retirement	-	958	479			479			Result of gain or loss on asset retirements
Repair & Maintenance 481 a Adjustment	-	2,728,409	1,364,205			1,364,205			Portion of Repairs & Maintenance 481a Adjustment offset in Account 182
Repair & Maintenance Deduction	-	240,234	120,117			120,117			Portion of Repairs & Maintenance deduction offset in Account 182
Additional State Depreciation VA	-	(1,966,541)	(983,271)			(983,271)			Temporary difference for additional state depreciation allowed for VA tax return
Additional State Depreciation MD	-	(7,188,355)	(3,594,178)			(3,594,178)			Temporary difference for additional state depreciation allowed for MD tax return
AFUDC Equity Flow Through	-	238,513	119,257			119,257			Portion of AFUDC Equity that relates to property and booked to account 282
Cost of Removal	-	(312,253)	(156,127)			(156,127)			Temporary difference arising for removal of plant/property
MACRS/ACRS Property Retired Retail	-	107,599	53,800			53,800			Result of gain or loss on asset retirements
Pension Expense - Capital Portion	-	1,133	567			567			Temporary difference from Pension Expense that is Capitalized as property and booked to account 282 (instead of account 283)
Subtotal	269,349,403	398,213,974	333,781,688			333,781,688			
Less FASB 109 included above	2,874,719	3,533,841	3,204,280			3,204,280			
Less FASB 106 included above	-	-	-			-			
Total	266,474,684	394,680,133	330,577,408			330,577,408			

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.

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT-283	**Beg of Year Balance p276.19.b**	**End of Year Balance p277.19.k**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Deferred Tax Reclassification	-	-	-			-			ADIT balance sheet reclassification
Regulated Asset Prexy LT	-	-	-			-			Regulatory asset for Prexy reclassification
WV Rate Change Consol Benefit	-	-	-			-			Temporary difference due to change in state tax rate in West Virginia
Reg Asset PJM Receivable -ST	39,282,708	34,434,127	36,858,418			36,858,418			Comparison of actual to forecast revenues - non-property related
Reg Asset PJM Receivable - LT	-	-	-			-			Comparison of actual to forecast revenues - non-property related
WV State Property Tax	344,853	1,062,586	703,720			703,720			West Virginia property tax payment
Intercompany Charge AESC	-	1,414,001	707,001			707,001			Intercompany charges from the service company
Deferred Charge EIB	-	-	-			-			Allocated portion of total liabilities relating to captive insurance
Unamortized Loss on Reacquired Debt	2,912,061	1,940,464	2,426,263			2,426,263			Unamortized debt expenses for existing debt that is refinanced and amortized over the life of the new debt
Power Tax Adjustment	43,613	43,628	43,621			43,621			System adjustment to reclass balances to correct FERC accounts
Pension Manual Company Allocation	33,833	-	16,917			16,917			Result of a change in pension methodology
Purchase Accounting Adj. Amortization	115,793	-	57,897		57,897				The merger has been accounted for under the purchase method of accounting and being eliminated for FERC accounting purposes.
State Income Taxes	144,799	-	72,400			72,400			Return/Accrual (catch up entry)
Energy Insurance Service Cell	-	2,478	1,239			1,239			Temporary difference resulting from deferred charges for Energy Insurance services
AFUDC Equity Flow Through	-	142,415	71,208			71,208			The tax portion (gross-up) of the AFUDC Equity booked in account 282
PA Apportionment Change Impact	-	254,152	127,076			127,076			Result of the impact of the PA Apportionment Change from a 90% sales factor to a 100% sales factor. This rate change will later be assigned on an M item basis
State Income Tax - Federal Deferred Only	-	1,896,963	948,482			948,482			Temporary difference resulting from the timing between when state income taxes are paid and when thery are deductible on the federal tax return
Subtotal	42,877,660	41,190,814	42,034,237		57,897	41,976,341	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	42,877,660	41,190,814	42,034,237		57,897	41,976,341	-	-	

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.

Trans-Allegheny Interstate Line Company

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	FERC Form No.1 page, line & Col	Amount	Allocator	Allocated Amount
	Plant Related			**Gross Plant Allocator**	
1.1	2011 State Property WV	p263.1.2(i)	613,134	100.0000%	$ 613,134
1.2	2012 State Property WV	p263.1.3(i)	2,391,738	100.0000%	2,391,738
1.3	2011 State Property PA (PURTA)	p263.25(i)	21,929	100.0000%	21,929
1.4	2012 State Property PA (PURTA)	p263.26(i)	20,770	100.0000%	20,770
1.5	2010 Local Property WV	p263.1.13(i)	75,950	100.0000%	75,950
1.6	2011 Local Property WV	p263.1.14(i)	617,858	100.0000%	617,858
1.7	2012 Local Property WV	p263.1.15(i)	296,043	200.0000%	296,043
1.8	2012 Local Property VA	p263.1.18(i)	1,342,105	100.0000%	1,342,105
1.9	2012 Local Property PA	p263.1.21(i)	2,904	100.0000%	2,904
2.1	2011 Local Property MD	p263.1.24(i)	695,101	100.0000%	695,101
2.2	2012 Local Property MD	p263.1.25(i)	676,158	100.0000%	676,158
2.3	2012 Capital Stock Tax/Franchise MD	p263.10(i)	300	100.0000%	300
2.4	2011 Capital Stock Tax/Franchise PA	p263.23(i)	-37,122	100.0000%	-37,122
2.5	2012 Capital Stock Tax/Franchise PA	p263.24(i)	188,961	100.0000%	188,961
2.6					
2.7	2011 WV Franchise Tax	p263.39(i)	10,291	100.0000%	10,291
3.1	2012 WV Franchise Tax	p263.40(i)	86,086	100.0000%	86,086
3.2	Capital Stock Tax/Franchise All States			100.0000%	0
3.3	Gross Premium MD			100.0000%	0
4.1	Gross Premium PA			100.0000%	0
4.2				100.0000%	0
4.3	State Sales Tax PA	p263.22(i)	1,712	100.0000%	1,712
6.1	State License WV			100.0000%	0
6.5	Federal Excise Tax	p263.5(i)	832	100.0000%	832
8	**Total Plant Related**		7,004,750	100.0000%	7,004,750
	Labor Related			**Wages & Salary Allocator**	
9	Accrued Federal FICA	p263.3(i)	171,526		
10	Accrued Federal Unemployment	p263.4(i)	7,094		
11	State Unemployment	p263.1.10(i)	32,076		
12					
13					
14	**Total Labor Related**		210,696	100.0000%	210,696
	Other Included			**Gross Plant Allocator**	
15	2011 MD GRT	p263.13(i)	6,447		6,447
16	2012 MD GRT	p263.14(i)	8,622		8,622
17					0
18					
19	**Total Other Included**		15,069	100.0000%	15,069
20	**Total Included (Lines 8 + 14 + 19)**		7,230,515		**7,230,515** Input to Appendix A, Line 82
	Retail Related Other Taxes to be Excluded				
21	Federal Income Tax	p263.2(i)	8,914,424		
22	Corporate Net Income Tax MD	p263.9(i)	2,653,117		
23	Corporate Net Income Tax PA	p263.19(i)	7,571,612		
24	Corporate Net Income Tax VA	p263.31(i)	8,490,541		
25	Corporate Net Income Tax WV	p263.37(i)	31,672,736		
26					
27					
28					
29					
30					
31	**Subtotal, Excluded**		59,302,430		
32	**Total, Included and Excluded (Line 20 + Line 28)**		66,532,945		
33	**Total Other Taxes from p114.14.c**		7,230,515		
34	**Difference (Line 32 - Line 33)**		59,302,430		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they shall 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 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 Gross 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.

Trans-Allegheny Interstate Line Company

Attachment 3 - Revenue Credit Workpaper

			Amount	FERC Form No.1 page, line & Col
	Account 454 - Rent from Electric Property			
1	Rent from Electric Property - Transmission Related (Note 3)		-	Page 300 Line: 19 Column: b
2	Total Rent Revenues	(Line 1)	-	
	Account 456 - Other Electric Revenues (Note 1)			
3	Schedule 1A		-	
4	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) (Note 4)		-	
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		3,335,876	p328-330 Footnote Data Schedule Page: 328 Line: 1 Column: m
6	PJM Transitional Revenue Neutrality (Note 1)			
7	PJM Transitional Market Expansion (Note 1)			
8	Professional Services (Note 3)		-	
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)			
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-	
11	Gross Revenue Credits	(Sum Lines 2-10)	3,335,876	
12	Less line 14g		-	
13	Total Revenue Credits	(Line 11 - Line 12)	3,335,876	Input to Appendix A, Line 131
	<u>Revenue Adjustment to determine Revenue Credit</u>			
14a	Revenues associated with lines 14b-g are to be included in lines 2-10 and total of those revenues entered here		-	
14b	Costs associated with revenues in line 14a		-	
14c	Net Revenues (14a - 14b)		-	
14d	50% Share of Net Revenues (14c / 2)		-	
14e	Costs associated with revenues in line 14a 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)		-	
14g	Line 14a less line 14f		-	
15	Amount offset in line 4 above		-	
16	Total Account 454 and 456		3,335,876	

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 line 178 of Appendix A.

18 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.

19 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). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: 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).

20 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 of the PJM OATT are not included in the total above to the extent they are credited under Schedule 12 of the PJM OATT.

Trans-Allegheny Interstate Line Company

Attachment 4 - Calculation with Incentive ROE

	Return and Taxes at High End of the range of Reasonableness				
A	Return and Taxes at High End of the range of Reasonableness	(Sum Lines 26 and 33 from below)		161,830,407	Input to Appendix A, Line 140
B	Difference between Base ROE and Incentive ROE			100	

Return Calculation

			Source Reference		
1	Rate Base		Appendix A, Line 46		1,107,090,785
2	Preferred Dividends	enter positive	Appendix A, Line 84		0
	Common Stock				
3	Proprietary Capital		Appendix A, Line 85		665,442,241
4	Less Accumulated Other Comprehensive Income Account 219		Appendix A, Line 86		0
5	Less Preferred Stock		Appendix A, Line 87		0
6	Less Account 216.1		Appendix A, Line 88		0
7	Common Stock		Appendix A, Line 89		665,442,241
	Capitalization				
8	Long Term Debt		Appendix A, Line 90		450,000,000
9	Less Unamortized Loss on Reacquired Debt		Appendix A, Line 91		4,917,402
10	Plus Unamortized Gain on Reacquired Debt		Appendix A, Line 92		0
11	Less ADIT associated with Gain or Loss		Appendix A, Line 93		-1,940,464
12	Total Long Term Debt		Appendix A, Line 94		447,023,062
13	Preferred Stock		Appendix A, Line 95		0
14	Common Stock		Appendix A, Line 96		665,442,241
15	Total Capitalization		Appendix A, Line 97		1,112,465,303
16	Debt %	Total Long Term Debt	Appendix A, Line 98		40.1831%
17	Preferred %	Preferred Stock	Appendix A, Line 99		0.0000%
18	Common %	Common Stock	Appendix A, Line 100		59.8169%
19	Debt Cost	Total Long Term Debt	Appendix A, Line 101		0.0489
20	Preferred Cost	Preferred Stock	Appendix A, Line 102		0.0000
21	Common Cost	Common Stock		12.70%	0.1270
22	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 16 * 19)		0.0196
23	Weighted Cost of Preferred	Preferred Stock	(Line 17 * 20)		0.0000
24	Weighted Cost of Common	Common Stock	(Line 18 * 21)		0.0760
25	Rate of Return on Rate Base (ROR)		(Sum Lines 22 to 24)		**0.0956**
26	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 25)**		**105,840,450**

Composite Income Taxes

	Income Tax Rates			
27	FIT=Federal Income Tax Rate		Appendix A, Line 109	35.00%
28	SIT=State Income Tax Rate or Composite		Appendix A, Line 110	7.64%
29	p = percent of federal income tax deductible for state purposes		Appendix A, Line 111	0.00%
30	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	Appendix A, Line 112	39.97%
31	T/ (1-T)		Appendix A, Line 113	66.57%
32	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		55,989,957
33	**Total Income Taxes**		**(Line 32)**	**55,989,957**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Plant in Service Worksheet

	A	C	D	E	F	G
5		Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				
6					13 Month Balance for Reconciliation	EOY Balance for Estimate
7		**Calculation of Transmission Plant In Service**	Source		Total	Total
8		December	p206.58.b	For 2011	1,205,050,414	
9		January	company records	For 2012	1,208,767,205	
10		February	company records	For 2012	1,209,390,815	
11		March	company records	For 2012	1,214,526,363	
12		April	company records	For 2012	1,214,199,264	
13		May	company records	For 2012	1,214,199,264	
14		June	company records	For 2012	1,214,199,264	
15		July	company records	For 2012	1,204,355,656	
16		August	company records	For 2012	1,205,186,761	
17		September	company records	For 2012	1,205,828,402	
18		October	company records	For 2012	1,206,505,853	
19		November	company records	For 2012	1,207,150,462	
20		December	p207.58.g	For 2012	1,209,952,076	1,209,952,076
21	15	**Transmission Plant In Service**			**1,209,177,831**	**1,209,952,076**
22					**Link to Appendix A, line 15**	**Link to Appendix A, line 15**
23		**Calculation of Distribution Plant In Service**	Source			
24		December	p206.75.b	For 2011	-	
25		January	company records	For 2012	-	
26		February	company records	For 2012	-	
27		March	company records	For 2012	-	
28		April	company records	For 2012	-	
29		May	company records	For 2012	-	
30		June	company records	For 2012	-	
31		July	company records	For 2012	-	
32		August	company records	For 2012	-	
33		September	company records	For 2012	-	
34		October	company records	For 2012	-	
35		November	company records	For 2012	-	
36		December	p207.75.g	For 2012	-	-
37		**Distribution Plant In Service**			-	-
38						
39		**Calculation of Intangible Plant In Service**	Source			
40		December	p204.5.b	For 2011	13,258,079	
41		December	p205.5.g	For 2012	13,472,726	13,472,726
42	18	**Intangible Plant In Service**			**13,365,403**	**13,472,726**
43					Link to Appendix A, line 18	**Link to Appendix A, line 18**
44		**Calculation of General Plant In Service**	Source			
45		December	p206.99.b	For 2011	53,085,367	-
46		December	p207.99.g	For 2012	53,131,377	**53,131,377**
47	18	**General Plant In Service**			**53,108,372**	**53,131,377**
48					**Link to Appendix A, line 18**	**Link to Appendix A, line 18**
49		**Calculation of Production Plant In Service**	Source			
50		December	p204.46b	For 2011	-	
51		January	company records	For 2012	-	
52		February	company records	For 2012	-	
53		March	company records	For 2012	-	
54		April	company records	For 2012	-	
55		May	company records	For 2012	-	
56		June	company records	For 2012	-	
57		July	company records	For 2012	-	
58		August	company records	For 2012	-	
59		September	company records	For 2012	-	
60		October	company records	For 2012	-	
61		November	company records	For 2012	-	
62		December	p205.46.g	For 2012	-	-
63		**Production Plant In Service**			-	-
64						
65						
66	6	**Total Plant In Service**	Sum of averages above		**1,275,651,605**	**1,276,556,179**
67					**Link to Appendix A, line 6**	**Link to Appendix A, line 6**

Details

13 Month Plant Balance For reconciliation

	Black Oak	Wylie Ridge	502 Junction - Territorial Line	Meadowbrook Transformer	North Shenandoah	Bedington Transformer	Meadow Brook SS Capacitor	Kammer Transformers	Doubs Replacement Transformer #2	Doubs Replacement Transformer #3	Doubs Replacement Transformer #4	Cabot Substation	Total
8	46,608,218	18,117,703	1,054,465,680.39	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,472,610	5,700,321	6,656,922.91	1,205,050,414
9	46,608,218	18,268,428	1,057,475,919.24	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,678,399	5,700,321	7,006,960.42	1,208,767,205
10	46,608,153	18,277,186	1,057,976,431.63	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,241	5,700,321	7,111,523.39	1,209,390,815
11	46,608,153	22,852,073	1,058,522,761.33	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,214,526,363
12	46,608,153	22,852,073	1,058,195,662.33	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,214,199,264
13	46,608,153	22,852,073	1,058,195,662.33	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,214,199,264
14	46,608,153	22,852,073	1,058,195,662.33	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,214,199,264
15	46,608,153	22,852,073	1,048,352,054.25	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,204,355,656
16	46,608,153	22,852,073	1,049,183,159.70	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,205,186,761
17	46,608,153	22,852,073	1,049,824,800.71	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,205,828,402
18	46,608,153	22,852,073	1,050,502,251.98	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,206,505,853
19	46,608,153	22,852,073	1,051,146,861	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,207,150,462
20	46,608,153	22,852,073	1,053,948,475	8,202,934	1,923,902	7,723,539	6,496,239	39,532,735	5,149,610	4,688,959	5,700,321	7,125,136	1,209,952,076
21	**46,608,163**	**21,783,388**	**1,054,306,568**	**8,202,934**	**1,923,902**	**7,723,539**	**6,496,239**	**39,532,735**	**5,149,610**	**4,671,449**	**5,700,321**	**7,078,982**	**1,209,177,831**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Accumulated Depreciation Worksheet

	A	C	D	E	F: 13 Month Balance for Reconciliation	G: EOY Balance for Estimate
70		Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				
72		**Calculation of Transmission Accumulated Depreciation**	Source			
73		December	Prior year FERC Form 1 p219.25.b	For 2011	27,450,386	
74		January	company records	For 2012	29,802,711	
75		February	company records	For 2012	32,172,069	
76		March	company records	For 2012	34,545,580	
77		April	company records	For 2012	36,723,842	
78		May	company records	For 2012	39,101,976	
79		June	company records	For 2012	41,480,110	
80		July	company records	For 2012	43,858,245	
81		August	company records	For 2012	46,237,101	
82		September	company records	For 2012	48,615,957	
83		October	company records	For 2012	50,994,091	
84		November	company records	For 2012	53,372,225	
85		December	p219.25.b	For 2012	55,471,672	55,471,672
86	23	**Transmission Accumulated Depreciation**			**41,525,074**	**55,471,672**
87					**Link to Appendix A, line 23**	**Link to Appendix A, line 23**
88		**Calculation of Distribution Accumulated Depreciation**	Source			
89		December	Prior year FERC Form 1 p219.26.b	For 2011	-	
90		January	company records	For 2012	-	
91		February	company records	For 2012	-	
92		March	company records	For 2012	-	
93		April	company records	For 2012	-	
94		May	company records	For 2012	-	
95		June	company records	For 2012	-	
96		July	company records	For 2012	-	
97		August	company records	For 2012	-	
98		September	company records	For 2012	-	
99		October	company records	For 2012	-	
100		November	company records	For 2012	-	
101		December	p219.26.b	For 2012	-	-
102		**Distribution Accumulated Depreciation**			-	-
103						
104		**Calculation of Intangible Accumulated Depreciation**	Source			
105		December	Prior year FERC Form 1 p200.21.b	For 2011	1,237,850	
106		December	p200.21b	For 2012	3,161,074	3,161,074
107	25	**Accumulated Intangible Depreciation**			**2,199,462**	**3,161,074**
108					**Link to Appendix A, line 25**	**Link to Appendix A, line 25**
109		**Calculation of General Accumulated Depreciation**	Source			
110		December	Prior year FERC Form 1 p219.28b	For 2011	1,408,629	
111		December	p219.28.b	For 2012	2,554,609	2,554,609
112	24	**Accumulated General Depreciation**			**1,981,619**	**2,554,609**
113					**Link to Appendix A, line 24**	**Link to Appendix A, line 24**
114		**Calculation of Production Accumulated Depreciation**	Source			
115		December	Prior year FERC Form 1 p219.20.b-24.b	For 2011	-	
116		January	company records	For 2012	-	
117		February	company records	For 2012	-	
118		March	company records	For 2012	-	
119		April	company records	For 2012	-	
120		May	company records	For 2012	-	
121		June	company records	For 2012	-	
122		July	company records	For 2012	-	
123		August	company records	For 2012	-	
124		September	company records	For 2012	-	
125		October	company records	For 2012	-	
126		November	company records	For 2012	-	
127		December	p219.20.b thru 219.24.b	For 2012	-	-
128		**Production Accumulated Depreciation**			-	-
129						
130						
131	8	**Total Accumulated Depreciation**	Sum of averages above		**45,706,155**	**61,187,355**
132					**Link to Appendix A, line 8**	**Link to Appendix A, line 8**
133						

Details

13 Month Balance For Reconciliation

	Black Oak	Wylie Ridge	502 Junction - Territorial Line	Meadowbrook Transformer	North Shenandoah	Bedington Transformer	Meadow Brook SS Capacitor	Kammer Transformers	Doubs Replacement Transformer #2	Doubs Replacement Transformer #3	Doubs Replacement Transformer #4	Cabot Substation	Total
73	5,422,052	1,366,929	16,991,756	599,546	137,442	429,741	303,488	1,843,590	114,400	50,598	190,843	-	27,450,386
74	5,536,195	1,398,711	19,059,373	613,901	140,808	443,257	314,857	1,912,773	123,412	58,602	200,822	-	29,802,711
75	5,650,339	1,430,688	21,131,370	628,256	144,175	456,780	326,225	1,981,955	132,423	66,795	210,800	12,262	32,172,069
76	5,764,482	1,466,619	23,203,380	642,611	147,542	470,296	337,594	2,051,137	141,435	74,997	220,779	24,707	34,545,580
77	5,878,626	1,311,169	25,275,929	656,967	150,909	483,812	348,962	2,120,319	150,409	78,767	230,795	37,176	36,723,842
78	5,992,770	1,351,160	27,348,478	671,322	154,276	497,328	360,331	2,189,502	159,345	86,970	240,850	49,645	39,101,976
79	6,106,913	1,391,152	29,421,027	685,677	157,643	510,844	371,699	2,258,684	168,282	95,172	250,904	62,114	41,480,110
80	6,221,056	1,431,143	31,493,576	700,032	161,009	524,361	383,067	2,327,866	177,218	103,375	260,958	74,583	43,858,245
81	6,335,200	1,471,134	33,566,846	714,387	164,376	537,877	394,436	2,397,049	186,154	111,578	271,013	87,052	46,237,101
82	6,449,343	1,511,125	35,640,117	728,742	167,743	551,393	405,804	2,466,231	195,090	119,780	281,067	99,521	48,615,957
83	6,563,486	1,551,116	37,712,666	743,097	171,110	564,909	417,173	2,535,413	204,027	127,983	291,121	111,990	50,994,091
84	6,677,629	1,591,107	39,785,215	757,452	174,477	578,425	428,541	2,604,596	212,963	136,185	301,175	124,459	53,372,225
85	6,791,773	1,631,098	41,579,077	771,808	177,844	591,942	439,909	2,673,778	221,899	144,388	311,230	136,928	55,471,672
86	**6,106,913**	**1,454,089**	**29,400,678**	**685,677**	**157,643**	**510,843**	**371,699**	**2,258,684**	**168,235**	**96,553**	**250,950**	**63,111**	**41,525,074**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Row	Line	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Reference	Form 1 Amount	Electric Portion		Non-electric Portion	Details
136		**Materials and Supplies**			Beg of year	End of Year (for estimate)		Average of Beginning and Ending Balances	
137	40	Transmission Materials & Supplies		p227.8	-	-		-	
138	37	Undistributed Stores Expense		p227.16	-	-		-	
139		**Allocated General Expenses**							
140	51	Plus Property Under Capital Leases	0	p200.4.c	-	-		-	

Transmission / Non-transmission Cost Support

Row	Line	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Reference	Beg of year	End of Year (for estimate)	Average of Beginning and Ending Balances	Details
145	34	**Transmission Related Land Held for Future Use**	Total	-	-	-	Enter Details Here
146			Non-transmission Related	-	-	-	
147			Transmission Related	-	-	-	

CWIP & Expensed Lease Worksheet

Row	Line	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Reference	Beg of year	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
152		**Plant Allocation Factors**						
153	6	Electric Plant in Service	(Note B)	Attachment 5	1,271,393,860	-	-	
154		**Plant In Service**						
155	15	Transmission Plant In Service	(Note B)	Attachment 5	1,205,050,414	-	-	
156		**Accumulated Depreciation**						
157	23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	27,450,386	-	-	

Pre-Commercial Costs Capitalized

Row	Line	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	EOY for Estimate and BOY for Final	Amortization Amount (Over 4 Years)	Calculated End of Year Balance	Average of Beginning and Ending Balances (for estimate and reconciliation)
162	35	**Unamortized Capitalized Pre-Commercial Costs**	$ -	$ -	$ -	$ -

EPRI Dues Cost Support

		Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	EPRI Dues	Details
167		**Allocated General & Common Expenses**					
168	58	Less EPRI Dues	(Note D)	p352 & 353			Enter Details Here

Regulatory Expense Related to Transmission Cost Support

Row	Line	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Reference	Form 1 Amount	Transmission Related	Non-transmission Related		Details
172		**Directly Assigned A&G**							
173	62	Regulatory Commission Exp Account 928	(Note G)	p323.189.b	-	-	-	Link to Appendix A, line 62	Enter Details Here

Safety Related Advertising Cost Support

Row	Line	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Reference	Form 1 Amount	Safety Related	Non-safety Related		Details
177		**Directly Assigned A&G**							
178	66	General Advertising Exp Account 930.1	(Note F)	p323.191.b	9	-	-	Link to Appendix A, line 66	Enter Details Here

MultiState Workpaper

Row	Line	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	State 1	State 2	State 3	State 4	State 5	Details
182		**Income Tax Rates**		MD 8.25%	WV 7.75%	PA 9.99%	VA 6.0%		
183				Composite	Composite is calculated based on sales, payroll and property for each jurisdiction				
184	110	SIT=State Income Tax Rate or Composite	(Note H)	7.6405%					

Education and Out Reach Cost Support

Row	Line	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Reference	Form 1 Amount	Education & Outreach	Other	Details
188		**Directly Assigned A&G**						
189	63	General Advertising Exp Account 930.1	(Note J)	p323.191.b	9	-	9	Enter Details Here

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Excluded Plant Cost Support

Link to Appendix 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			
126	Excluded Transmission Facilities	(Note L)		General Description of the Facilities
	Step-Up Facilities		-	
	Instructions:		Enter $	
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,		Or	
	the following formula will be used:	**Example**	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

Prepayments

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	Average of Beginning and Ending Balances	Allocation	Transmission Related	Details
36	**Prepayments**				Enter $		Amount	
	Prepayments	Prepaid Insurance	92,352	77,275	84,814	100%	84,814	
	Prepaid Pensions if not included in Prepayments		-	0	0	100%	0	
	Total Prepayments		**92,352**	**77,275**	84,814		84,814	

Detail of Account 566 Miscellaneous Transmission Expenses

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Total	Details
70	Amortization Expense on Pre-Commercial Cost		$ -	
71	Pre-Commercial Expense		-	
72	Miscellaneous Transmission Expense		706,234	
	Total Account 566 Miscellaneous Transmission Expenses	p.321	$ 706,234	

Summary of Pre-Commercial Expenses

Cost Element Name	Total
Labor & Overhead (1)	-
Miscellaneous (2)	-
Outside Services Legal (3)	-
Outside Services Other (4)	-
Outside Services Rates (5)	-
Advertising (6)	-
Travel, Lodging and Meals (7)	-
Total	-

(1) Labor & overhead amount includes costs allocated to preparation of the preliminary survey and investigation.
(2) Miscellaneous amount includes rental of volunteer fire department facilities for open houses, Fed EX fees for various mailings from Legal, Procurement, Transmission & Finance, fees for various conference calls and PJM application fee.
(3) Outside legal services includes the cost for research and preparation of the filing to determine incentive rate availability.
(4) Other services other includes fees for website development, media relations services, campaign management, open houses and research services.
(5) Outside services rates includes the advice of a rate consultant regarding rate design.
(6) Advertising includes newspaper and other media announcements of public scoping meetings related to the proposed project.
(7) Travel, lodging and meals are the direct expenses for Allegheny staff to attend the scoping meetings.

	Net Revenue Requirement	
149	Facility Credits under Section 30.9 of the PJM OATT	-

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Depreciation Rates

		Life		Survivor Curve	Net Salvage Percent	Accrual Rate (Annual) Percent
TRANSMISSION PLANT						
350.2	Land & Land Rights - Easements	70	-	R4	0	1.43
352	Structures & Improvements	50	-	R3	(10)	2.20
	SVC	35	-			2.86
353	Station Equipment					
	Other	50	-	R2	(5)	2.10
	SVC	Note 1	-	80 R2 - 35-yr truncation		2.96
	SCADA	15	-	S3	0	6.67
354	Towers & Fixtures	65	-	R4	(25)	1.92
355	Poles & Fixtures	55	-	R2.5	(20)	2.18
356	Overhead Conductors & Devices					
	Other	55	-	R2.5	(40)	2.80
	Clearing	70	-	R4	0	1.43
357	Underground conduit	55	-	S3	(5)	1.91
358	Underground conductor and devices	45	-	R3	(5)	2.33
	SVC	35				2.86
Total Transmission Plant Depreciation						

Annual Depreciation Expense

		Black Oak	Wylie Ridge	502 Junction - Territorial Line	Meadowbrook Transformer	North Shenandoah	Bedington Transformer	Meadow Brook SS Capacitor	Kammer Transformers	Doubs Replacement Transformer #2	Doubs Replacement Transformer #3	Doubs Replacement Transformer #4	Cabot SS	Total
350.2	Land & Land Rights - Easements	-	-	675,495	-	-	-	-	-	-	-	-	-	675,495
352	Structures & Improvements	-	-	55,163	-	-	-	-	-	-	-	-	-	55,163
	SVC	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-
353	Station Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other	15,999	459,724	1,944,861	172,262	40,402	162,194	123,782	830,187	107,499	98,222	120,387	136,928	4,212,446
	SVC	1,353,720	-	-	-	-	-	-	-				-	1,353,720
	SCADA	-	-	-				12,639	-	-	-	-	-	12,639
		-	-	-	-	-	-	-	-	-	-	-	-	-
354	Towers & Fixtures	-	-	1,706,577	-	-	-	-	-	-	-	-	-	1,706,577
355	Poles & Fixtures	-	-	6,800,203	-	-	-	-	-	-	-	-	-	6,800,203
		-	-	-	-	-	-	-	-	-	-	-	-	-
356	Overhead Conductors & Devices	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other	-	-	12,920,484	-	-	-	-	-	-	-	-	-	12,920,484
	Clearing	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-
357	Underground conduit	-	-	-	-	-	-	-	-	-	-	-	-	-
358	Underground conductor and devices	-	-	-	-	-	-	-	-	-	-	-	-	-
	SVC	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Transmission Plant Depreciation		1,369,720	459,724	24,102,783	172,262	40,402	162,194	136,421	830,187	107,499	98,222	120,387	136,928	27,736,728

Total Transmission Depreciation Expense (must tie to p336.7.f) 27,736,728

Note 1: Depreciation rate is based on an 80 R2 survivor curve with a 35-year truncation.

GENERAL PLANT		**Life**	**Survivor Curve**	Net Salvage Percent	Accrual Rate (Annual) Percent	**Total**
390	Structures & Improvements	50	R1	0	2.00	916,084
391	Office Furniture & Equipment	20	SQ	0	5.00	78,112
	Information Systems	10	SQ	0	10.00	16,518
	Data Handling	10	SQ	0	10.00	-
392	Transportation Equipment					
	Other	15	SQ	20	5.33	-
	Autos	7	S3	20	11.43	-
	Light Trucks	11.5	L4	20	6.96	5,428
	Medium Truck	11.5	L4	20	6.96	-
	Trailers	18	L1	20	4.44	-
	ATV	15	SQ	20	5.33	-
393	Stores Equipment	20	SQ	0	5.00	-
394	Tools, Shop & Garage Equipment	20	SQ	0	5.00	-
396	Power Operated Equipment	18	L1	25	4.17	-
397	Communication Equipment	15	SQ	0	6.67	129,837
398	Miscellaneous Equipment	15	SQ	0	6.67	-
Total General Plant						1,145,979

Total General Plant Depreciation Expense (must tie to p336.10.b & c) 1,145,979

INTANGIBLE PLANT		**Life**	**Survivor Curve**	Net Salvage Percent	Accrual Rate (Annual) Percent	**Total**
303	Miscellaneous Intangible Plant	5	SQ	0	20.00	1,923,223
Total Intangible Plant						1,923,223

Total Intangible Plant Amortization (must tie to p336.1 d & e) 1,923,223

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

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

PBOP Expenses

	1	Total PBOP expenses	22,856,433
	2	Amount relating to retired personnel	8,786,372
	3	Amount allocated on FTEs	14,070,061
	4	Number of FTEs for Allegheny	4,408
	5	Cost per FTE	3,192
	6	TrAILCo FTEs (labor not capitalized) current year	51.700
	7	TrAILCo PBOP Expense for base year	165,023
	8	TrAILCo PBOP Expense in Account 926 for current year	53,015
57	9	PBOP Adjustment for Appendix A, Line 57	112,008
		Lines 1-5 cannot change absent approval or acceptance by FERC in a separate proceeding.	

Trans-Allegheny Interstate Line Company

Attachment 5a - Pre-Commercial Costs and CWIP

Step 1 Totals reported below are by project with the amounts to be expensed reported separately from those to be deferred and amortized (note, deferred costs related to 2006 include AFUDC).

For Forecasting purposes, Pre-Commercial expenses will be estimated. Total deferred and amortized Pre-commercial costs will be the actual amount agreeing to FERC Form 1 and Attachment 5.

Step 2 For each project, where CWIP is to be recovered in rate base, CWIP will be estimated and the totals reported below by project. For the Reconciliation, for each project where CWIP is to be recovered in rate base the CWIP will be itemized by project below. Additionally, the amount of AFUDC that would have been capitalized for projects where CWIP is included in rate base will be reported in the FERC Form No. 1.

Step 3 For the Reconciliation, the total additions to plant in service for that year will be summarized by project to demonstrate no Pre-Commercial costs expensed were included in the additions to plant in service and AFUDC on projects where CWIP was recovered in rate base was included in the additions to plant in service. The Pre-commercial expenses are actual expenses incurred for the reconciliation year. Total deferred and amortized Pre-commercial costs will be the actual amount agreeing to FERC Form 1 and Attachment 5.

	Column A	Column B	Column C	Column D		Column E	Column F	Column G
			Pre-Commercial Costs			CWIP		
Step 1	**For Estimate:**	Expensed (Estimated)	Deferred	Amount of Deferred Amortized in Year	**Estimate Step 2**	Average of 13 Monthly Balances		
	Prexy - 502 Junction 138 kV (CWIP)	-		-		-		
	Prexy - 502 Junction 500 kV (CWIP)	-		-		-		
	502 Junction - Territorial Line (CWIP)	-		-		-		
	Total	-	-	-		-		
Step 3	**For Reconciliation:**		Pre-Commercial Costs		**For Reconciliation Step 2**	CWIP	AFUDC In CWIP	AFUDC (If CWIP was not in Rate Base)
	Prexy - 502 Junction 138 kV (CWIP)	Expensed (Actual)	Deferred	Amount of Deferred Amortized in Year				
	1	-	-	-		-	-	
	2	-	-	-		-	-	
	3	-	-	-		-	-	
	4	-	-	-		-	-	
	...							
	Total	-	-	-		-	-	
	Prexy - 502 Junction 500 kV (CWIP)							
	1	-	-	-		-	-	
	2	-	-	-		-	-	
	3	-	-	-		-	-	
	4	-	-	-		-	-	
	...							
	Total	-	-	-		-	-	
	502 Junction - Territorial Line (CWIP)							
	1	-	-	-		-	-	-
	2	-	-	-		-	-	-
	3	-	-	-		-	-	-
	4	-	-	-		-	-	-
	...							
	Total	-	-	-		-	-	-

Total Additions to Plant In Service (sum of the above for each project)	Refer to Attachment 5 - Cost Support Plant in Service Worksheet	-
Total Additions to Plant in Service reported on pages 204-207 of the Form No. 1	Refer to Attachment 5 - Cost Support Plant in Service Worksheet	
Difference (must be zero)		

Notes:

1 Small projects may be combined into larger projects where rate treatment is consistent. Pre-Commercial costs benefiting multiple projects will be allocated to projects based on the estimated plant in service of each project.

Allocation of Pre-Commercial Costs	Plant in Service (Estimated 2/12/2008)	Allocation
Prexy - 502 Junction 138 kV (CWIP)	94,140,000	0.10734
Prexy - 502 Junction 500 Kv (CWIP)	121,260,000	0.13827
502 Junction - Territorial Line (CWIP)	661,600,000	0.75439
Total	877,000,000	1.00000

2 Column D is the total CWIP balance including any AFUDC, Column E is the AFUDC if any in Column D, and Column F is the AFUDC that would have been in Column E if CWIP were not recovered in rate base.

Trans-Allegheny Interstate Line Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 based on each project's cost using the average of 13 monthly balances. Cap Adds are the projects expected to be in service in Year 2.
3	April	Year 2	TO adds Cap Adds and CWIP to plant in service in Formula (Appendix A, Lines 16 and 33)
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect
6	April	Year 3	TO estimates all transmission Cap Adds and CWIP during Year 3 based each project's cost using the average of 13 monthly balances. Cap Adds are expected be in service in Year 3.
7	April	Year 3	Reconciliation - TO calculates Reconciliation by populating the 13 monthly plant balances and beginning and end of year balances for the other rate base items and the 13 monthly averages for CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year).
8	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Step 5 with interest to the result of Step 7 (this difference is also added to Step 7 in the subsequent year)
9	May	Year 3	Post results of Step 8 on PJM web site
10	June	Year 3	Results of Step 8 go into effect

Reconciliation Details

1 April Year 2 TO populates the formula with Year 1 data

Rev Req based on Year 1 data — Must run Appendix A to get this number (without any cap adds in Appendix A line 16 and without CWIP in Appendix A line 33)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 based on each project's cost using the average of 13 monthly balances. Cap Adds are the projects expected to be in service in Year 2.

	(A)	(B) Potter SS (in service)	(C) Cabot SS Transformer (in service)	(D) Wylie Ridge Replace Transformer (in service)	(E) Doubs Transformer #3 (in service)	(F) (in service)	(G) 502 Junction - Territorial Line (monthly additions) CWIP	(H) CWIP	(I) CWIP
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-		1,958,927		
Jan 2012	Actual	-	350,038	150,725	205,790		3,117,148		
Feb	Actual	-	104,563	8,758	9,841		485,326		
Mar	Actual	-	13,613	4,574,887	718		545,391		
Apr	Budget	-	-	-	-		3,458,527		
May	Budget	-	-	-	-		1,677,292		
Jun	Budget	-	-	-	-		(10,700,836)		
Jul	Budget	2,100,000	-	-	-		261,732		
Aug	Budget	50,000	-	-	-		187,432		
Sep	Budget	-	-	-	-		424,260		
Oct	Budget	-	-	-	-		256,760		
Nov	Budget	-	-	-	-		248,310		
Dec	Budget	-	-	-	-		2,223,860		
Total		2,150,000	468,213	4,734,369	216,349	-	4,144,128	-	-

Month End Balances

	Other Projects PIS (Monthly additions)	Potter SS	Cabot SS Transformer	Wylie Ridge Replace Transformer	Doubs Transformer #3 (in service)	(in service)	502 Junction - Territorial Line (monthly additions) CWIP		
Dec (Prior Year CWIP) p216.b.43	[redacted]	-	-	-	-	-	1,958,927	-	-
Jan 2012		-	350,038	150,725	205,790	-	5,076,074	-	-
Feb		-	454,600	159,483	215,631	-	5,561,400	-	-
Mar		-	468,213	4,734,369	216,349	-	6,106,791	-	-
Apr		-	468,213	4,734,369	216,349	-	9,565,318	-	-
May		-	468,213	4,734,369	216,349	-	11,242,610	-	-
Jun		-	468,213	4,734,369	216,349	-	541,774	-	-
Jul		2,100,000	468,213	4,734,369	216,349	-	803,506	-	-
Aug		2,150,000	468,213	4,734,369	216,349	-	990,938	-	-
Sep		2,150,000	468,213	4,734,369	216,349	-	1,415,198	-	-
Oct		2,150,000	468,213	4,734,369	216,349	-	1,671,958	-	-
Nov		2,150,000	468,213	4,734,369	216,349	-	1,920,268	-	-
Dec		2,150,000	468,213	4,734,369	216,349	-	4,144,128	-	-
Total		**12,850,000**	**5,486,770**	**47,653,903**	**2,584,906**	**-**	**50,998,887**	**-**	**-**
		988,462	422,059	3,665,685	198,839	-	3,922,991	-	-
	(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 16)			(Appendix A, Line 33)		

3 April Year 2 TO adds Cap Adds and CWIP to plant in service in Formula (Appendix A, Lines 16 and 33)

4 May Year 2 Post results of Step 3 on PJM web site

Total Revenue Requirement	Potter SS	Cabot SS Transformer	Doubs Transformer #4 (Monthly additions)	Doubs Transformer #3 (Monthly additions)	Doubs Transformer #2 (Monthly additions)	Kammer Transformers (Monthly additions)	Meadow Brook SS Capacitor (Monthly additions)	Bedington Transformer (Monthly additions)	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)
$ 193,707,398	136,566	978,031	880,499	689,015	801,041	6,092,715	1,000,671	1,169,874	1,222,745	287,219	7,459,861	3,154,502	169,834,660

5 June Year 2 Results of Step 3 go into effect

6 April Year 3 TO estimates all transmission Cap Adds and CWIP during Year 3 based each project's cost using the average of 13 monthly balances. Cap Adds are expected be in service in Year 3.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Potter SS	Pleasureville Capacitor	Farmers Valley Capacitor	Harvey Run Capacitor	Osage Whitely SS WP	Osage Whitely SS MP	Buffalo Road Capacitor	502 Junction - Territorial Line (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	-	267,486
Jan 2013	Actual	2,665,904	-	-	-	-	-	-	(1,577,481)
Feb	Actual	3,614	-	-	-	-	-	-	1,197,338
Mar	Actual	2,036	-	-	-	-	-	-	485,502
Apr	Actual	300,912	-	-	-	-	-	-	367,955
May	Budget	-	-	959,961	-	-	-	-	568,482
Jun	Budget	-	1,319,617	-	499,205	13,191,570	6,487,910	-	1,072,808
Jul	Budget	-	-	-	-	-	-	-	197,279
Aug	Budget	-	-	-	-	-	-	-	301,835
Sep	Budget	-	-	-	-	-	-	-	91,790
Oct	Budget	-	-	-	-	-	-	922,010	601,374
Nov	Budget	-	-	-	-	-	-	-	1,374
Dec	Budget	-	-	-	-	-	-	-	1,154,713
Total		2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	922,010	4,730,456
New Transmission Plant Additions for Year 3 (13 month average balance)									

Month End Balances								
Other Projects PIS (Monthly additions)	Potter SS	Pleasureville Capacitor	Farmers Valley Capacitor	Harvey Run Capacitor	Osage Whitely SS WP	Osage Whitely SS MP	Buffalo Road Capacitor	502 Junction - Territorial Line (monthly additions)
				(in service)	(in service)	(in service)	(in service)	CWIP
	-	-	-	-	-	-	-	267,486
	2,665,904	-	-	-	-	-	-	(1,309,995)
	2,669,519	-	-	-	-	-	-	(112,657)
	2,671,555	-	-	-	-	-	-	372,845
	2,972,467	-	-	-	-	-	-	740,801
	2,972,467	-	959,961	-	-	-	-	1,309,282
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	-	2,382,090
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	-	2,579,369
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	-	2,881,205
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	-	2,972,995
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	922,010	3,574,369
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	922,010	3,575,743
	2,972,467	1,319,617	959,961	499,205	13,191,570	6,487,910	922,010	4,730,456
	34,759,177	**9,237,316**	**7,679,691**	**3,494,438**	**92,340,988**	**45,415,373**	**2,766,031**	**23,963,991**
	2,673,783	710,563	590,745	268,803	7,103,153	3,493,490	212,772	1,843,384

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Shawville Capacitors	Grover Sub	Conemaugh Transformer	502 Junction Substation	
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)		(in service)
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-	-	-	-	-
Jan 2013	Actual	-	-	-	-	-	-	-	-
Feb	Actual	-	-	-	-	-	-	-	-
Mar	Actual	-	-	-	-	-	-	-	-
Apr	Actual	-	-	-	-	-	-	-	-
May	Budget	-	-	-	-	-	-	-	-
Jun	Budget	-	-	-	-	-	-	3,025,907	-
Jul	Budget	-	-	-	-	-	-	-	-
Aug	Budget	-	-	-	-	-	-	-	-
Sep	Budget	-	-	-	-	-	-	-	-
Oct	Budget	1,048,348	672,714	1,338,361	837,559	-	-	-	-
Nov	Budget	-	-	-	-	-	6,571,112	-	-
Dec	Budget	-	-	-	-	1,219,340	-	-	-
Total		1,048,348	672,714	1,338,361	837,559	1,219,340	6,571,112	3,025,907	-
New Transmission Plant Additions for Year 3 (13 month average balance)									

Month End Balances								
Other Projects PIS (Monthly additions)	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Shawville Capacitors	Grover Sub	Conemaugh Transformer	502 Junction Substation	
				(in service)	(in service)	(in service)	(in service)	(in service)
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	3,025,907	-
	-	-	-	-	-	-	3,025,907	-
	-	-	-	-	-	-	3,025,907	-
	-	-	-	-	-	-	3,025,907	-
	1,048,348	672,714	1,338,361	837,559	-	-	3,025,907	-
	1,048,348	672,714	1,338,361	837,559	-	6,571,112	3,025,907	-
	1,048,348	672,714	1,338,361	837,559	1,219,340	6,571,112	3,025,907	-
	3,145,043	**2,018,142**	**4,015,083**	**2,512,676**	**1,219,340**	**13,142,225**	**21,181,347**	**-**
	241,926	155,242	308,853	193,283	93,795	1,010,940	1,629,334	-

Buffalo Road Capacitor	Osage Whitely SS MP	Osage Whitely SS WP	Harvey Run Capacitor	Farmers Valley Capacitor	Pleasureville Capacitor	Pottet SS	Cabot SS Transformer	Doubs Transformer #4 (Monthly additions)	Doubs Transformer #3 (Monthly additions)	Doubs Transformer #2 (Monthly additions)	Kammer Transformers (Monthly additions)	Meadow Brook SS Capacitor (Monthly additions)	Bedington Transformer (Monthly additions)	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)
$ 27,700	454,801.92	924,727.81	34,994.25	76,906.51	92,504.99	348,088	1,046,692	821,969	689,859	749,016	5,628,691	924,868	1,090,625	1,139,687	267,713	6,927,031	3,222,388	165,659,996

Total Revenue Requirement	Grandview Capacitor	Luxor Capacitor	Grand Point & Guilford SS	Shawville Capacitors	Grover Sub	Conemaugh Transformer	502 Junction Substation			
$ 190,601,269.13	31,495.32	20,210.23	40,208.13	25,162.63	12,210.80	131,610	212,116			

7 April Year 3 Reconciliation - TO calculates Reconciliation by populating the 13 monthly plant balances and beginning and end of year balances for the other rate base items and the 13 monthly averages for CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year).

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Potter SS	Cabot SS Transformer	Transformer	Doubs Transformer #3	Line (monthly additions)			
		(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual	-	-	-	-		1,958,927		
Jan 2012	Actual	-	-	-	-		106,909		
Feb	Actual	-	-	-	-		(15,187)		
Mar	Actual	-	-	-	-		(939)		
Apr	Actual	-	-	-	-		2,423,718		
May	Actual	-	-	-	-		1,440,102		
Jun	Actual	-	-	-	-		(10,139,258)		
Jul	Actual	-	-	-	-		10,989,877		
Aug	Actual	-	-	-	-		437,364		
Sep	Actual	-	-	-	-		204,207		
Oct	Actual	-	-	-	-		132,916		
Nov	Actual	-	-	-	-		165,103		
Dec	Actual	-	-	-	-		267,486		
Total		-	-	-	-	-	7,971,225	-	-

Month End Balances

(Monthly additions)	Potter SS	Cabot SS Transformer	Transformer	Doubs Transformer #3		(monthly additions)		
				(in service)	(in service)	CWIP		
[redacted]	-	-	-	-	-	1,958,927	-	-
	-	-	-	-	-	2,065,836	-	-
	-	-	-	-	-	2,050,649	-	-
	-	-	-	-	-	2,049,710	-	-
	-	-	-	-	-	4,473,428	-	-
	-	-	-	-	-	5,913,530	-	-
	-	-	-	-	-	(4,225,728)	-	-
	-	-	-	-	-	6,764,149	-	-
	-	-	-	-	-	7,201,513	-	-
	-	-	-	-	-	7,405,720	-	-
	-	-	-	-	-	7,538,636	-	-
	-	-	-	-	-	7,703,739	-	-
	-	-	-	-	-	7,971,225	-	-
	-	**-**	**-**	**-**	**-**	**58,871,331**	**-**	**-**
	-	-	-	-	-	4,528,564	-	-

Result of Formula for Reconciliation

Total Revenue Requirement	Pottet SS	Cabot SS Transformer	Doubs Transformer #4 (Monthly additions)	Doubs Transformer #3 (Monthly additions)	Doubs Transformer #2 (Monthly additions)	Kammer Transformers (Monthly additions)	Meadow Brook SS Capacitor (Monthly additions)	Bedington Transformer (Monthly additions)	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)
$ 192,403,109.66	$ -	$ 1,061,633.46	$ 838,624.20	$ 701,201.66	$ 764,053.98	$ 5,742,978.36	$ 943,647.12	$ 1,112,841.33	$ 1,163,050.36	$ 273,198.28	$ 7,092,860.52	$ 3,139,163.92	$ 169,569,856.47

8 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Step 5 with interest to the result of Step 7 (this difference is also added to Step 7 in the subsequent year)

The Reconciliation in Step 8 — The forecast in Prior Year

192,403,110 - 193,707,398 = (1,304,288) <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.

Interest on Amount of Refunds or Surcharges

Interest 35.19a for March Current Yr 0.2700%

Month	Yr	1/12 of Step 9	Interest 35.19a for		Interest	Surcharge (Refund) Owed
Jun	Year 2	(1,325,418)	0.2700%	(112,399)	(1,216,597)	
Jul	Year 2	(1,216,597)	0.2700%	(112,399)	(1,107,482)	
Aug	Year 2	(1,107,482)	0.2700%	(112,399)	(998,073)	
Sep	Year 2	(998,073)	0.2700%	(112,399)	(888,368)	
Oct	Year 2	(888,368)	0.2700%	(112,399)	(778,367)	
Nov	Year 2	(778,367)	0.2700%	(112,399)	(668,069)	
Dec	Year 2	(668,069)	0.2700%	(112,399)	(557,474)	
Jan	Year 3	(557,474)	0.2700%	(112,399)	(446,579)	
Feb	Year 3	(446,579)	0.2700%	(112,399)	(335,386)	
Mar	Year 3	(335,386)	0.2700%	(112,399)	(223,892)	
Apr	Year 3	(223,892)	0.2700%	(112,399)	(112,097)	
May	Year 3	(112,097)	0.2700%	(112,399)	-	
Total with interest				(1,348,794)		

The difference between the Reconciliation in Step 8 and the forecast in Prior Year with interest (1,348,794) **Input to Appendix A, Line 143**

Rev Req based on Year 2 data with estimated Cap Adds for Year 3 (Step 8) $ 190,601,269

Revenue Requirement for Year 3 189,252,475

Reconciliation Amount by Project

Total Revenue Requirement	Pottet SS	Cabot SS Transformer	Doubs Transformer #4 (Monthly additions)	Doubs Transformer #3 (Monthly additions)	Doubs Transformer #2 (Monthly additions)	Kammer Transformers (Monthly additions)	Meadow Brook SS Capacitor (Monthly additions)	Bedington Transformer (Monthly additions)	Meadowbrook Transformer (Monthly additions)	North Shenandoah (Monthly additions)	Black Oak (Monthly additions)	Wylie Ridge (Monthly additions)	502 Junction - Territorial Line (Monthly additions)
$ **(1,348,794)**	(141,226)	$ 86,455	$ (43,304)	$ 12,603	$ (38,249)	$ (361,671)	$ (58,969)	$ (58,979)	$ (61,731)	$ (14,499)	$ (379,523)	$ (15,862)	$ (273,839)

9 May Year 3 Post results of Step 8 on PJM web site

$ 189,252,475

10 June Year 3 Results of Step 8 go into effect

$ 189,252,475

Trans-Allegheny Interstate Line Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 **Revenue Requirement By Project**

		Formula Line		
2	**Fixed Charge Rate (FCR) if not a CIAC**			
3	A	137	FCR without Depreciation and Pre-Commercial Costs	13.0186%
4	B	145	FCR with Incentive ROE without Depreciation and Pre-Commercial	13.9573%
5	C		Line B less Line A	0.9388%
6	**FCR if a CIAC**			
7	D	138	FCR without Depreciation, Return, nor Income Taxes	0.1847%

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**

Line				PJM Upgrade ID: b0328.1 b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	PJM Upgrade ID: b0218	PJM Upgrade ID: b0216
10		Details		502 Junction - Territorial Line (CWIP + Plant In Service)	Wylie Ridge Transformer (Plant In Service)	Black Oak (SVC) Dynamic Reactive Device (Plant In Service)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No
13	Input the allowed ROE	Allowed ROE		12.70%	11.70%	12.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	FCR without Incentive ROE		13.0186%	13.0186%	13.0186%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	FCR for This Project		13.9573%	13.0186%	13.9573%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	Investment		1,014,212,782	21,220,974	39,816,381
17	Annual Depreciation Exp from Attachment 5			24,102,783	459,724	1,369,720

Line			Invest Yr	Return	Depreciation	Pre-Commercial Exp.	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
18																
19	See Calculations for each item below	Wo Incentive ROE	2011	132,035,840.68	24,102,782.69	0.00	(273,839.21)	155,864,784.16	2,762,664.03	459,723.58	(15,861.91)	3,206,525.70	5,183,517.08	1,369,719.64	(379,523.11)	6,173,713.60
20	See Calculations for each item below	W Incentive ROE	2011	141,557,212.83	24,102,782.69	0.00	(273,839.21)	165,386,156.31	2,762,664.03	459,723.58	(15,861.91)	3,206,525.70	5,557,311.00	1,369,719.64	(379,523.11)	6,547,507.53

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commercial expense on Attachment 5a for each project expensed in year and amortized in year.
Revenue is equal to the "Return" ("Investment" times FCR) plus "Depreciation" plus "Pre-Commercial Exp" plus prior year "Reconciliation amount"
"Reconciliation Amount" is created in the reconciliation in Attachment 6 and included in the forecasted revenue requirement.

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Line		PJM Upgrade ID: b0323				PJM Upgrade ID: b0230				PJM Upgrade ID: b0229				PJM Upgrade ID: b0559			
10		North Shenandoah Transformer (Plant In Service)				Meadowbrook Transformer (Plant In Service)				Bedington Transformer (Plant In Service)				Meadowbrook Capacitor (Plant In Service)			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%				13.0186%				13.0186%				13.0186%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%				13.0186%				13.0186%				13.0186%			
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	1,746,058				7,431,126				7,131,597				6,056,330			
17	Annual Depreciation Exp from Attachment 5	40,402				172,262				162,194				136,421			
18		Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	227,311.53	40,401.96	(14,499.22)	253,214.27	967,425.22	172,261.56	(61,731.27)	1,077,955.51	928,430.83	162,194.37	(58,978.61)	1,031,646.59	788,446.58	136,421.04	(58,969.31)	865,898.31
20	See Calculations for each item below	227,311.53	40,401.96	(14,499.22)	253,214.27	967,425.22	172,261.56	(61,731.27)	1,077,955.51	928,430.83	162,194.37	(58,978.61)	1,031,646.59	788,446.58	136,421.04	(58,969.31)	865,898.31

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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Line	Description	PJM Upgrade ID: b0495				PJM Upgrade ID: b0343				PJM Upgrade ID: b0344				PJM Upgrade ID: b0345			
10		Kammer Transformers (Plant In Service)				Doubs Replace Transformer #2				Doubs Replace Transformer #3				Doubs Replace Transformer #4			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes				Yes				Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No				No				No			
13	Input the allowed ROE	11.70%				11.70%				11.70%				11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%				13.0186%				13.0186%				13.0186%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%				13.0186%				13.0186%				13.0186%			
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	36,858,958				4,927,711				4,544,571				5,389,092			
17	Annual Depreciation Exp from Attachment 5	830,187				107,499				98,222				120,387			
18		Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue	Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	4,798,503.36	830,187.46	(361,670.89)	5,267,019.93	641,516.78	107,499.24	(38,248.83)	710,767.19	591,637.44	98,221.67	12,602.96	702,462.08	701,581.81	120,386.76	(43,303.53)	778,665.04
20	See Calculations for each item below	4,798,503.36	830,187.46	(361,670.89)	5,267,019.93	641,516.78	107,499.24	(38,248.83)	710,767.19	591,637.44	98,221.67	12,602.96	702,462.08	701,581.81	120,386.76	(43,303.53)	778,665.04

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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Line		PJM Upgrade ID: b0704	PJM Upgrade ID: b1243	PJM Upgrade ID: b2148	PJM Upgrade ID: b0563	PJM Upgrade ID: b0564
10		Cabot SS - Install Autotransformer	Potter Substation	Pleasureville Capacitor	Farmers Valley Capacitor	Harvey Run Capacitor
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes	Yes	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No	No	No	No	No
13	Input the allowed ROE	11.70%	11.70%	11.70%	11.70%	11.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%	13.0186%	13.0186%	13.0186%	13.0186%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%	13.0186%	13.0186%	13.0186%	13.0186%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	6,988,208	2,673,783	710,563	590,745	268,803
17	Annual Depreciation Exp from Attachment 5	136,928	0	0	0	0

Line		b0704 Return	b0704 Depreciation	b0704 Reconciliation Amount	b0704 Revenue	b1243 Return	b1243 Depreciation	b1243 Reconciliation Amount	b1243 Revenue	b2148 Return	b2148 Depreciation	b2148 Reconciliation Amount	b2148 Revenue
19	See Calculations for each item below	909,763.63	136,928.26	86,454.86	1,133,146.75	348,087.87	0.00	(141,225.69)	206,862.19	92,504.99	0.00	0.00	92,504.99
20	See Calculations for each item below	909,763.63	136,928.26	86,454.86	1,133,146.75	348,087.87	0.00	(141,225.69)	206,862.19	92,504.99	0.00	0.00	92,504.99

Line		b0563 Return	b0563 Depreciation	b0563 Reconciliation Amount	b0563 Revenue	b0564 Return	b0564 Depreciation	b0564 Reconciliation Amount	b0564 Revenue
19	See Calculations for each item below	76,906.51	0.00	0.00	76,906.51	34,994.25	0.00	0.00	34,994.25
20	See Calculations for each item below	76,906.51	0.00	0.00	76,906.51	34,994.25	0.00	0.00	34,994.25

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

Line	Description	PJM Upgrade ID: b0674, and b1023.3	PJM Upgrade ID: b1023.2	PJM Upgrade ID: b1770	PJM Upgrade ID: b1990
1					
2					
3					
4					
5					
6					
7					
8					
9					
10		Osage Whiteley (WP)	Osage Whiteley (MP)	Buffalo Road Capacitor	Grandview Capacitor
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No	No	No	No
13	Input the allowed ROE	11.70%	11.70%	11.70%	11.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%	13.0186%	13.0186%	13.0186%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%	13.0186%	13.0186%	13.0186%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	7,103,153	3,493,490	212,772	241,926
17	Annual Depreciation Exp from Attachment 5	0	0	0	0

Line	Description	Osage Whiteley (WP) Return	Depreciation	Reconciliation Amount	Revenue	Osage Whiteley (MP) Return	Depreciation	Reconciliation Amount	Revenue	Buffalo Road Capacitor Return	Depreciation	Reconciliation Amount	Revenue	Grandview Capacitor Return	Depreciation	Reconciliation Amount	Revenue
18																	
19	See Calculations for each item below	924,727.81	0.00	0.00	924,727.81	454,801.92	0.00	0.00	454,801.92	27,699.78	0.00	0.00	27,699.78	31,495.32	0.00	0.00	31,495.32
20	See Calculations for each item below	924,727.81	0.00	0.00	924,727.81	454,801.92	0.00	0.00	454,801.92	27,699.78	0.00	0.00	27,699.78	31,495.32	0.00	0.00	31,495.32

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

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Line	Description	PJM Upgrade ID: b1965 — Luxor Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%			
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	155,242			
17	Annual Depreciation Exp from Attachment 5	0			
18		Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	20,210.23	0.00	0.00	20,210.23
20	See Calculations for each item below	20,210.23	0.00	0.00	20,210.23

Line	Description	PJM Upgrade ID: b1839 — Grand Point & Guildford SS			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%			
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	308,853			
17	Annual Depreciation Exp from Attachment 5	0			
18		Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	40,208.13	0.00	0.00	40,208.13
20	See Calculations for each item below	40,208.13	0.00	0.00	40,208.13

Line	Description	PJM Upgrade ID: b1998 — Shawville Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%			
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	193,283			
17	Annual Depreciation Exp from Attachment 5	0			
18		Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	25,162.63	0.00	0.00	25,162.63
20	See Calculations for each item below	25,162.63	0.00	0.00	25,162.63

Line	Description	PJM Upgrade ID: b0556 — Grover SS Capacitor			
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes			
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No			
13	Input the allowed ROE	11.70%			
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%			
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%			
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	93,795			
17	Annual Depreciation Exp from Attachment 5	0			
18		Return	Depreciation	Reconciliation Amount	Revenue
19	See Calculations for each item below	12,210.80	0.00	0.00	12,210.80
20	See Calculations for each item below	12,210.80	0.00	0.00	12,210.80

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

Line	Description	PJM Upgrade ID: b1153				PJM Upgrade ID: b0674 & b1023.1				PJM Upgrade ID: bxxx							
1																	
2																	
3																	
4																	
5																	
6																	
7																	
8																	
9																	
10		Conemaugh Transformer				502 Junction Substation											
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes											
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No											
13	Input the allowed ROE	11.70%				11.70%											
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	13.0186%				13.0186%											
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	13.0186%				13.0186%											
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	1,010,940				1,629,334											
17	Annual Depreciation Exp from Attachment 5	0				0											
18		**Return**	**Depreciation**	**Reconciliation Amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation Amount**	**Revenue**	**Return**	**Depreciation**	**Reconciliation Amount**	**Revenue**	**Total**	**Incentive Charged**	**Revenue Credit**	$9,895,166.08
19	See Calculations for each item below	131,609.82	0.00	0.00	131,609.82	212,115.78	0.00	0.00	212,115.78	0.00	0.00	0.00	0.00	179,357,309.32		179,357,309.32	**Ax A Line 148**
20	See Calculations for each item below	131,609.82	0.00	0.00	131,609.82	212,115.78	0.00	0.00	212,115.78	0.00	0.00	0.00	0.00	189,252,475.39	189,252,475.39		

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commer
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in Att

Template for Annual Information Filings with Formula Rate Debt Cost Disclosure and True-Up
Attachment 8, page 1, Table 1 and 2
Template for Annual Information Filings with Formula Rate Debt Cost Disclosure and True-Up

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT/Hypothetical Example

YEAR ENDED 12/31/2014

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	t=N	Issue Date	Maturity Date	ORIGINAL ISSUANCE	Net Proceeds At Issuance	Net Amount Outstanding at t=N	Months Outstanding at t=N	Average Net Outstanding in Year* z*	Weighted Outstanding Ratios	Effective Cost Rate (Tables 2 and 3)	Weighted Debt Cost at t = N (h) * (i)	
	Long Term Debt 12/31/2014											
	First Mortgage Bonds:											
(1)	7.09%, Debenture Description, Series, Name of	1/1/2014	8/31/2030	$ 300,000,000	$ 294,600,000	$ 295,000,000	12	$ 295,156,250	66.23%	7.324%	4.8506%	
(2)	Coupon rate, Debenture Description, Series, N	1/1/2014	6/30/2025									
	Other Long Term Debt:											
(3)	6.6%, Medium Term Notes, Series, Name of I	04/01/2014	06/30/2024	$ 200,000,000	$ 198,000,000	$ 150,000,000	9	$ 150,200,000	33.70%	6.735%	2.2697%	
(4)	$1,000,000 variable rate LT Credit Line Dr	xx/xx/xxx	xx/xx/xxx	na	na	$ 359,000	12	$ 320,000	0.07%	6.590%	0.0047%	
	Series, Name of Issuer											
	Total			$ 500,000,000		$ 445,359,000		$ 445,676,250	100.000%		7.13%	**

t = time
The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.
The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.
* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).
Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).
** This Total Weighted Average Debt Cost will be shown on Line 101 of formula rate Appendix A.

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

YEAR ENDED 12/31/2014

		(aa)	(bb)	(cc)	(dd)	14	(ee)	(ff)	(gg)	(hh)	(ii)	(jj)	(kk)	(ll)
	Long Term Debt Affiliate	Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance		Issuance Expense	Loss/Gain on Reacquired Debt	Less Related ADIT (Attachment 1)	Net Proceeds	Net Proceeds Ratio	Coupon Rate	Annual Interest	Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
	First Mortgage Bonds													
(1)	7.09%, Debenture Des No	1/1/2014	6/30/2025	$ 300,000,000	$ (2,400,000)		$ 3,000,000	-	xxx	$ 294,600,000	98.2000	0.07090	$ 21,270,000	7.324%
(2)	Coupon rate, Debenture Description, Series, N	xxx	xxx	xxx	xxx		xxx	xxx	xxx	xxx	xxxx	xxx	xxxx	xx.xxxx
	Other Long Term Debt:												-	
(3)	6.6%, Medium Term N No	4/1/2014	06/30/2024	200,000,000			2,000,000		xxx	$ 198,000,000	99.0000	0.06600	13,200,000	6.735%
	TOTALS			$ 500,000,000	(2,400,000)		$ 5,000,000	-	xxx	$ 492,600,000			$ 34,470,000	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation
Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_o equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Trans-Allegheny Interstate Line Company

Attachment 9 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology

TrAILCo anticipates its financing will be a 7 year loan, where by TrAILCo pays Origination Fees of $5.2 million and a Commitments Fee of 0.3% on the undrawn principle.
Consistent with GAAP, TrAILCo will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return formula below.
Each year, TrAILCo will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$**	**900,000,000**

Internal Rate of Return[1] **4.886348%**

Based on following Financial Formula[2]:

$$\textbf{NPV = 0 =} \sum_{t=1}^{N} Ct/(1+IRR)pwr(t)$$

Origination Fees		
Origination Fees		7,780,954
Addition Origination Fees		15,125
Total Issuance Expense		**7,796,079**

	New Borrowing	Old Borrowing	
Revolving Credit Commitment Fee	0.005	0.0050	
Revolving Credit Commitment Fee		0.0037	After borrowing is at the midpoint ($275,000)

	2008	2008	2008	2008	2009	2010	2011	2012	2013	2014	2015
LIBOR Rate	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Spread	.	.	.	.	.	.	.	.	.	.	.
Interest Rate	6.13%	3.86%	4.05%	4.34%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%
Bond $450M Interest Rate	$ 450,000,000					4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Revolver Interest Rate	$ 350,000,000	Draw 1	DONE			3.249%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 2, 3, 4	DONE			3.247%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 5	DONE			3.251%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 6	DONE - Roll over Draw 1 and 4			3.316%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 7	DONE			3.361%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 8	DONE - Roll over Draw 2, 3 and 5			3.422%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 9	DONE			3.417%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 10	DONE			3.348%	4.50%	6.21%			
Revolver Interest Rate	$ 350,000,000	Draw 11	DONE - Roll over Draw 6 and 9			3.498%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 12	DONE - Roll over Draw 10			3.418%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 13	DONE - Roll over Draw 7 and 8			3.398%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 14	DONE			3.275%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 15	DONE			3.275%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 16	DONE - Roll over Draw 11			3.289%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 17	DONE			3.248%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 17A	DONE - Roll over Draw 12, 14 and 15			3.286%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 18	DONE - Roll over Draw 13 and 17			3.286%	4.50%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 19	DONE				3.283%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 20	DONE - Roll over Draw 16				3.304%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 21	DONE - Roll over Draw 17A and 19				3.312%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 22	DONE - Roll over Draw 18				3.312%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 23	DONE				3.222%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 24	DONE Roll over Draw 20				3.213%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 25	DONE Roll over Draw 21, 22 and 23				3.174%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 26	DONE Roll over Draw 25				3.169%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 27	DONE - Pay off Draw 26				3.196%	6.21%			
Revolver Interest Rate	$ 450,000,000	Draw 28	DONE				1.936%	6.21%			

				GL '224100		GL '820204	GL '181100/654106	GL '820202			
(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)	(I)		
Year		**Capital Expenditures**	**Principle Drawn In Quarter ($000's)**	**Principle Drawn To Date**	**Outstanding Debt Balance**	**Interest Expense**	**Origination Fees**	**Commitment**	**Net Cash Flows (D-F-G-H)**	**Interest at effective rate**	**Amortization of origination fees and commitment fees**
2008											
12/24/2007	Q4	68,183,000	10,000,000	10,000,000	10,000,000		734,955.02		9,265,045	-	-
01/31/2008	Q1			10,000,000	9,265,045		31,013.00		(31,013)	46,132	46,132
02/4/2008	Q1			10,000,000	9,280,164		69,578.45		(69,578)	4,853	4,853
02/6/2008	Q1			10,000,000	9,215,438		137.50		(138)	2,409	2,409
02/29/2008	Q1			10,000,000	9,217,710		2,960.00		(2,960)	27,752	27,752
03/5/2008	Q1			10,000,000	9,242,502		125,384.16		(125,384)	6,042	6,042
3/24/2008	Q1	25,543,000		10,000,000	9,123,160	155,047.57			(155,048)	22,684	(132,363)
03/31/2008	Q1			10,000,000	8,990,797		17,011.00		(17,011)	8,230	8,230
04/30/2008	Q2			10,000,000	8,982,016		197,269.56		(197,270)	35,289	35,289
05/19/2008	Q2			10,000,000	8,820,035		109,824.88		(109,825)	21,931	21,931
6/23/2008	Q2	20,509,000		10,000,000	8,732,141	97,477.43			(97,477)	40,038	(57,439)
06/26/2008	Q2			10,000,000	8,674,702		43,098.82		(43,099)	3,402	3,402
06/30/2008	Q2			10,000,000	8,635,005		13,267.50		(13,268)	4,516	4,516
08/8/2008	Q3			10,000,000	8,626,253		1,577.79		(1,578)	44,084	44,084
08/13/2008	Q3			10,000,000	8,668,760		62,776.98		(62,777)	5,667	5,667
8/15/2008	Q3		55,000,000	65,000,000	8,611,650	59,689.48	7,780,953.85		47,159,357	2,251	(57,438)
8/20/2008	Q3			65,000,000	55,773,258		530.00		(530)	36,461	36,461
8/25/2008	Q3			65,000,000	55,809,189		15,125.00		(15,125)	36,485	36,485
9/3/2008	Q3			65,000,000	55,830,549		82,654.66		(82,655)	65,714	65,714
9/8/2008	Q3			65,000,000	55,813,609		1,957.50		(1,958)	36,487	36,487
9/11/2008	Q3			65,000,000	55,848,138		41,845.84		(41,846)	21,903	21,903
9/15/2008	Q3		(20,000,000)	45,000,000	55,828,196	243,199.31			(20,243,199)	29,196	(214,004)
9/25/2008	Q3			45,000,000	35,614,192		7,525.25		(7,525)	46,580	46,580
9/29/2008	Q3			45,000,000	35,653,247		98,058.08		(98,058)	18,645	18,645
9/30/2008	Q3	24,995,000		45,000,000	35,573,834		18,136.90	235,520.83	(253,658)	4,650	4,650
10/2/2008	Q4		20,000,000	65,000,000	35,324,826			78,506.96	19,921,493	9,235	9,235
10/17/2008	Q4			65,000,000	55,255,554		2,030.03		(2,030)	108,439	108,439

Trans-Allegheny Interstate Line Company

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Total Loan Amount	**$**	**900,000,000**

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Based on following Financial Formula[2]**:**

$$NPV = 0 = \sum_{t=1}^{N} C_t/(1+IRR)pwr(t)$$

Origination Fees	
Origination Fees	7,780,954
Addition Origination Fees	15,125
Total Issuance Expense	7,796,079

	New Borrowing	Old Borrowing	
Revolving Credit Commitment Fee	0.005	0.0050	
Revolving Credit Commitment Fee		0.0037	After borrowing is at the midpoint ($275,000)

	10/29/2008	Q4			65,000,000	55,361,963		266.90		(267)	86,901	86,901
	11/19/2008	Q4			65,000,000	55,448,597		96,048.71		(96,049)	152,404	152,404
	11/21/2008	Q4			65,000,000	55,504,952		730.00		(730)	14,511	14,511
	12/15/2008	Q4		25,000,000	90,000,000	55,518,734	718,999.31			24,281,001	174,431	(544,569)
(1)	1/6/2009	Q1	42,068,000	-	90,000,000	79,974,165	-		618,333.53	(618,334)	230,297	230,297
	2/17/2009	Q1		30,000,000	120,000,000	79,586,128	-		-	30,000,000	438,097	438,097
	3/16/2009	Q1	75,475,000	40,000,000	160,000,000	110,024,225	933,987.50			39,066,013	388,964	(545,023)
	3/25/2009	Q1		-	160,000,000	149,479,202			1,100,000.00	(1,100,000)	175,942	175,942
	4/8/2009	Q2		-	160,000,000	148,555,144			549,166.67	(549,167)	272,085	272,085
	5/15/2009	Q2		50,000,000	210,000,000	148,278,062				50,000,000	718,820	718,820
	6/16/2009	Q2		40,000,000	250,000,000	198,996,882	1,405,039.11			38,594,961	834,057	(570,982)
	6/30/2009	Q2		-	250,000,000	238,425,899				-	436,686	436,686
	7/31/2009	Q3		-	250,000,000	238,862,586			453,194.44	(453,194)	969,797	969,797
	8/3/2009	Q3		30,000,000	280,000,000	239,379,188				30,000,000	93,882	93,882
	9/4/2009	Q3		50,000,000	330,000,000	269,473,071				50,000,000	1,129,444	1,129,444
	9/16/2009	Q3		-	330,000,000	320,602,515	1,596,826.11			(1,596,826)	503,245	(1,093,581)
	10/5/2009	Q4		45,000,000	375,000,000	319,508,934	207,916.06			44,792,084	794,450	586,534
	10/16/2009	Q4			375,000,000	365,095,468			321,250.00	(321,250)	525,294	525,294
	11/5/2009	Q4		30,000,000	405,000,000	365,299,512	-			30,000,000	956,176	956,176
	12/4/2009	Q4		50,000,000	455,000,000	396,255,688				50,000,000	1,504,831	1,504,831
	12/16/2009	Q4	73,715,000	-	455,000,000	447,760,519	1,374,479.16			(1,374,479)	702,843	(671,636)
	1/4/2010	Q1			455,000,000	447,088,883			138,489.58	(138,490)	1,111,675	1,111,675
	1/5/2010	Q1		30,000,000	485,000,000	448,062,068	892,331.11			29,107,669	58,568	(833,764)
	1/15/2010	Q1		-	485,000,000	477,228,304	440,625.00			(440,625)	624,167	183,542
	1/25/2010	Q1		(485,000,000)	-	477,411,847	423,000.00		18,489.58	(485,441,490)	624,407	201,407
	1/25/2010	Q1		450,000,000	450,000,000	(7,405,236)		4,533,000.00		445,467,000	-	-
	1/25/2010	Q1		45,000,000	495,000,000	438,061,764		5,852,578.67		39,147,421	-	-
	1/27/2010	Q1			495,000,000	477,209,186		6,979.59		(6,980)	124,763	124,763
	2/3/2010	Q1			495,000,000	477,326,969		58,000.00		(58,000)	436,922	436,922
	2/3/2010	Q1			495,000,000	477,705,891		5,500.00		(5,500)	-	-
	2/5/2010	Q1			495,000,000	477,700,391		82,116.73	2,934.74	(85,051)	124,892	124,892
	2/12/2010	Q1		20,000,000	515,000,000	477,740,231				20,000,000	437,300	437,300
	2/24/2010	Q1			515,000,000	498,177,531		23,770.00		(23,770)	781,982	781,982
	3/10/2010	Q1		30,000,000	545,000,000	498,935,743		90,000.00		29,910,000	913,821	913,821
	3/17/2010	Q1		-	545,000,000	529,759,564		195,720.20		(195,720)	484,916	484,916
	3/26/2010	Q1		20,000,000	565,000,000	530,048,759		17,821.04		19,982,179	623,885	623,885
	4/1/2010	Q2			565,000,000	550,654,823			255,416.67	(255,417)	432,008	432,008
	4/5/2010	Q2			565,000,000	550,831,415		123,660.90		(123,661)	288,060	288,060
	4/7/2010	Q2			565,000,000	550,995,814		201,250.00		(201,250)	144,054	144,054
	4/8/2010	Q2			565,000,000	550,938,618		224,587.75		(224,588)	72,015	72,015
	4/12/2010	Q1		30,000,000	595,000,000	550,786,045				30,000,000	288,036	288,036
	4/14/2010	Q2			595,000,000	581,074,082		194,134.74		(194,135)	151,918	151,918
	4/21/2010	Q2			595,000,000	581,031,865		18,977.41		(18,977)	531,848	531,848
	4/26/2010	Q2		(65,000,000)	530,000,000	581,544,735	369,573.75			(65,369,574)	380,177	10,603
	4/26/2010	Q2		65,000,000	595,000,000	516,555,339	55,920.56			64,944,079	-	(55,921)
	4/28/2010	Q2			595,000,000	581,499,418	-	2,300.79		(2,301)	152,029	152,029
	4/30/2010	Q2			595,000,000	581,649,147		2,156.70		(2,157)	152,068	152,068
	5/7/2010	Q2		30,000,000	625,000,000	581,799,058				30,000,000	532,550	532,550
	5/12/2010	Q2		(80,000,000)	545,000,000	612,331,608				(80,000,000)	400,304	400,304
	5/12/2010	Q2		80,000,000	625,000,000	532,731,912	160,694.44			79,839,306	-	(160,694)
	5/12/2010	Q2			625,000,000	612,571,218	81,275.00			(81,275)	-	(81,275)
	5/12/2010	Q2			625,000,000	612,489,943	170,100.00			(170,100)	-	(170,100)
	5/20/2010	Q2			625,000,000	612,319,843		182,500.00		(182,500)	640,599	640,599
	5/26/2010	Q2		20,000,000	645,000,000	612,777,942				20,000,000	480,746	480,746
	6/14/2010	Q2			645,000,000	633,258,687		150,071.58		(150,072)	1,574,581	1,574,581
	7/1/2010	Q3			645,000,000	634,683,197			230,764	(230,764)	1,411,820	1,411,820
	7/2/2010	Q3			645,000,000	635,864,253		1,168.50	-	(1,169)	83,116	83,116
	7/7/2010	Q3		35,000,000	680,000,000	635,946,200				35,000,000	415,741	415,741
	7/15/2010	Q3			680,000,000	671,361,942	8,500,000.00			(8,500,000)	702,368	(7,797,632)
	7/26/2010	Q3		(65,000,000)	615,000,000	663,564,309				(65,000,000)	954,726	954,726
	7/26/2010	Q3		(20,000,000)	595,000,000	599,519,036				(20,000,000)	-	-
	7/26/2010	Q3		115,000,000	710,000,000	579,519,036				115,000,000	-	-
	7/26/2010	Q3			710,000,000	694,519,036	115,798.33			(115,798)	-	(115,798)
	7/26/2010	Q2			710,000,000	694,403,237	544,837.22		-	(544,837)	-	(544,837)
	8/9/2010	Q3		(35,000,000)	675,000,000	693,858,400	107,415.00			(35,107,415)	1,270,829	1,163,414
	8/9/2010	Q3		35,000,000	710,000,000	660,021,814	-			35,000,000	-	-
	8/12/2010	Q3		(30,000,000)	680,000,000	695,021,814	271,680.83			(30,271,681)	272,581	900
	8/12/2010	Q3		(80,000,000)	600,000,000	665,022,714	699,608.89			(80,699,609)	-	(699,609)
	8/12/2010	Q3		110,000,000	710,000,000	584,323,106	-			110,000,000	-	-
	8/30/2010	Q3			710,000,000	694,323,106	-	407,816.09		(407,816)	1,635,445	1,635,445
	9/7/2010	Q3		30,000,000	740,000,000	695,550,735	-			30,000,000	727,674	727,674
	9/26/2010	Q3		-	740,000,000	726,278,408	-			-	1,805,872	1,805,872
	10/1/2010	Q4			740,000,000	728,084,280			**162,778**	(162,778)	475,975	475,975
	10/8/2010	Q4		30,000,000	770,000,000	728,397,478	-			30,000,000	666,739	666,739
	10/26/2010	Q4		(115,000,000)	655,000,000	759,064,217	1,028,023.33			(116,028,023)	1,787,940	759,916
	10/26/2010	Q4		115,000,000	770,000,000	644,824,133	-			115,000,000	-	-
	11/5/2010	Q4		30,000,000	800,000,000	759,824,133	-			30,000,000	993,774	993,774
	11/9/2010	Q4		(35,000,000)	765,000,000	790,817,908	305,721.11			(35,305,721)	413,562	107,841
	11/9/2010	Q4		(30,000,000)	735,000,000	755,925,749	171,937.50			(30,171,938)	-	(171,938)
	11/9/2010	Q4		(30,000,000)	705,000,000	725,753,811	86,853.33			(30,086,853)	-	(86,853)
	11/9/2010	Q4		95,000,000	800,000,000	695,666,958				95,000,000	-	-
	11/12/2010	Q4		(110,000,000)	690,000,000	790,666,958	955,215.56			(110,955,216)	310,092	(645,123)
	11/12/2010	Q4		(30,000,000)	660,000,000	680,021,835	18,946.67			(30,018,947)	-	(18,947)
	11/12/2010	Q4		140,000,000	800,000,000	650,002,888	5.83			139,999,994	-	(6)
	12/6/2010	Q4		20,000,000	820,000,000	790,002,882				20,000,000	2,482,059	2,482,059
	12/23/2010	Q4			820,000,000	812,484,941		8,281.46		(8,281)	1,807,331	1,807,331

Trans-Allegheny Interstate Line Company

Attachment 9 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology

TrAILCo anticipates its financing will be a 7 year loan, where by TrAILCo pays Origination Fees of $5.2 million and a Commitments Fee of 0.3% on the undrawn principle.
Consistent with GAAP, TrAILCo will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return formula below.
Each year, TrAILCo will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$**	**900,000,000**

Internal Rate of Return[1] **4.886348%**

Based on following Financial Formula[2]:

$$\text{NPV} = 0 = \sum_{t=1}^{N} C_t / (1+IRR)pwr(t)$$

Origination Fees	
Origination Fees	7,780,954
Addition Origination Fees	15,125
Total Issuance Expense	**7,796,079**

	New Borrowing	Old Borrowing	
Revolving Credit Commitment Fee	0.005	0.0050	
Revolving Credit Commitment Fee		0.0037	After borrowing is at the midpoint ($275,000)

1/3/2011	Q1			820,000,000	814,283,991			140,277.78	(140,278)	1,171,579	1,171,579
1/18/2011	Q1		-	820,000,000	815,315,292	9,000,000			(9,000,000)	1,600,050	(7,399,950)
1/26/2011	Q1		(115,000,000)	705,000,000	807,915,342	966,600.56			(115,966,601)	845,228	(121,373)
1/26/2011	Q1		115,000,000	820,000,000	692,793,969				115,000,000	-	-
2/9/2011	Q1		(20,000,000)	800,000,000	807,793,969	118,552.78			(20,118,553)	1,479,507	1,360,954
2/9/2011	Q1		(95,000,000)	705,000,000	789,154,923	797,767.78			(95,797,768)	-	(797,768)
2/9/2011	Q1		115,000,000	820,000,000	693,357,156				115,000,000	-	-
2/14/2011	Q1		(140,000,000)	680,000,000	808,357,156	1,201,215.56			(141,201,216)	528,453	(672,763)
2/14/2011	Q1		140,000,000	820,000,000	667,684,393				140,000,000	-	-
2/16/2011	Q1			820,000,000	807,684,393		3,098.63		(3,099)	211,164	211,164
4/1/2011	Q2		-	820,000,000	807,892,458			97,777.78	(97,778)	4,659,577	4,659,577
4/14/2011	Q2		10,000,000	830,000,000	812,454,257			-	10,000,000	1,381,663	1,381,663
4/26/2011	Q2		(115,000,000)	715,000,000	823,835,920	949,900.00			(115,949,900)	1,293,164	343,264
4/26/2011	Q2		115,000,000	830,000,000	709,179,184	-			115,000,000	-	-
5/9/2011	Q2		(115,000,000)	715,000,000	824,179,184	941,620.00			(115,941,620)	1,401,603	459,983
5/9/2011	Q2		(140,000,000)	575,000,000	709,639,166	1,081,920.00			(141,081,920)	-	(1,081,920)
5/9/2011	Q2		(10,000,000)	565,000,000	568,557,246	22,375.00			(10,022,375)	-	(22,375)
5/9/2011	Q2		235,000,000	800,000,000	558,534,871	-			235,000,000	-	-
5/16/2011	Q2		(235,000,000)	565,000,000	793,534,871	145,034.17			(235,145,034)	726,363	581,329
5/16/2011	Q2		235,000,000	800,000,000	559,116,200	-			235,000,000	-	-
5/23/2011	Q2		(235,000,000)	565,000,000	794,116,200	144,805.69			(235,144,806)	726,895	582,089
5/23/2011	Q2		50,000,000	615,000,000	559,698,289				50,000,000	-	-
5/26/2011	Q2		(115,000,000)	500,000,000	609,698,289	307,912.50	233,657		(115,541,569)	239,118	(68,795)
6/23/2011	Q2		(50,000,000)	450,000,000	494,395,838	88,994.45		-	(50,088,994)	1,812,670	1,723,675
6/23/2011	Q2		20,000,000	470,000,000	446,119,513	-		-	20,000,000	-	-
7/6/2011	Q3			470,000,000	466,119,513			171,736.11	(171,736)	792,685	792,685
7/15/2011	Q3			470,000,000	466,740,462	9,000,000			(9,000,000)	549,369	(8,450,631)
7/25/2011	Q3		(20,000,000)	450,000,000	458,289,831	34,417.78		-	(20,034,418)	599,398	564,980
10/18/2011	Q4			450,000,000	438,854,811			290,416.67	(290,417)	4,902,813	4,902,813
1/17/2012	Q1			450,000,000	443,467,207	9,000,000			(9,000,000)	5,306,145	(3,693,855)
3/2/2012	Q1			450,000,000	439,773,352		3,070.00		(3,070)	2,594,240	2,594,240
7/15/2012	Q3			450,000,000	442,364,522	9,000,000			(9,000,000)	7,874,847	(1,125,153)
1/15/2013	Q1			450,000,000	441,239,369	9,000,000			(9,000,000)	10,740,283	1,740,283
7/15/2013	Q3			450,000,000	442,979,652	9,000,000			(9,000,000)	10,604,752	1,604,752
1/15/2014	Q1			450,000,000	444,584,404	9,000,000			(9,000,000)	10,821,705	1,821,705
7/15/2014	Q3			450,000,000	446,406,108	9,000,000			(9,000,000)	10,686,780	1,686,780
1/15/2015	Q1		(450,000,000)	-	448,092,888	9,000,000			(459,000,000)	10,907,105	1,907,105
										-	-

Commitment fees for 4th quarter 2008

Attachment 4B-Delmarva Formula Rate Update

Pepco Holdings, Inc

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May 15, 2013

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, D.C. 20426

Re: Delmarva Power & Light Company ("Delmarva")
Informational Filing of 2013 Formula Rate Annual Update in
Docket No. ER09-1158 and Pursuant to Approved Settlement Agreement
in Docket Nos. ER05-515-000, *et al.*

Dear Ms. Bose,

Delmarva hereby submits electronically, for informational purposes, its 2013 Annual Formula Rate Update. On April 19, 2006, the Commission approved an uncontested settlement agreement ("Settlement") filed in Docket Nos. ER05-515-000, *et al*., (115 FERC ¶ 61,066). Formula rate implementation protocols contained in the Settlement provide that:

> [o]n or before May 15 of each year, Delmarva [Delmarva Power & Light Company] shall recalculate its Annual Transmission Revenue Requirements, producing an "Annual Update" for the upcoming Rate year, and:

(i) post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page; and

(ii) file such Annual Update with FERC as an informational filing.[1]

The same information has been transmitted to PJM for posting on its website as required by the formula rate implementation protocols. Thus, all interested parties should have ample notice of and access to the Annual Update. The protocols provide specific procedures for notice, review, exchanges of information and potential challenges to

[1] *See* Settlement Agreement, Exhibit B-1 containing PJM Tariff Attachment H3-E, Section 1.b.

aspects of the Annual Update. Consequently, and as the Commission has concluded, there is no need for the Commission to notice this informational filing for comment.[2]

Delmarva's 2013 Annual Update contains no expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices, as defined in 18 C.F.R. § 35.13(b)(7).

In 2012, Delmarva adopted revised general plant depreciation rates in its Maryland service territory, by order of the Maryland Public Service Commission.[3] Delmarva has made no additional Material Accounting Changes as defined in the Settlement.[4] Delmarva has made no change to Other Post-Employment Benefits ("OPEB") charges that exceed the filing threshold set forth in the Settlement.[5] Additionally, Delmarva has not recorded any extraordinary property losses in FERC Account 182.1. Therefore, no amortization is required over the periods described in the Settlement.[6]

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Very truly yours,

/s/ Amy L. Blauman

Amy L. Blauman
Associate General Counsel
Delmarva Power & Light Company

Enclosures

[2] *See* Letter Order Re: Annual Update to Formula Rate in Docket No. ER09-1158 (February 17, 2010).
[3] *See* MD PSC Order No. 85029 at 55-56.
[4] *See* Settlement Agreement, Exhibit B-3 containing PJM Tariff Attachment H-3E, Section 1 f.(iii).
[5] *See* Settlement Agreement, Exhibit B-3 containing PJM Tariff Attachment H-3E, Section 1.g.
[6] *See* Settlement Agreement, Exhibit B-3 containing PJM Tariff Attachment H-3E, Section 1 h.

ATTACHMENT H-3D

Delmarva Power & Light Company

Formula Rate - Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	2012
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	$ 1,884,202
2	Total Wages Expense		p354.28b	$ 34,752,202
3	Less A&G Wages Expense		p354.27b	$ 2,882,851
4	Total		(Line 2 - 3)	31,869,351
5	**Wages & Salary Allocator**		(Line 1 / 4)	**5.9123%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	$ 2,654,621,607
7	Common Plant In Service - Electric		(Line 24)	79,028,855
8	Total Plant In Service		(Sum Lines 6 & 7)	2,733,650,462
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	$ 912,945,741
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 23,288,342
11	Accumulated Common Amortization - Electric	(Note A)	p356	17,196,214
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	$ 45,575,480
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	999,005,777
14	Net Plant		(Line 8 - 13)	1,734,644,685
15	Transmission Gross Plant		(Line 29 - Line 28)	925,592,703
16	**Gross Plant Allocator**		(Line 15 / 8)	**33.8592%**
17	Transmission Net Plant		(Line 39 - Line 28)	621,286,161
18	**Net Plant Allocator**		(Line 17 / 14)	**35.8163%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 876,609,001
20	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year	For Reconciliation Only	Attachment 6 - Enter Negative	
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	37,626,069
22	**Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**914,235,070**
23	General & Intangible		p205.5.g & p207.99.g	113,073,907
24	Common Plant (Electric Only)	(Notes A & B)	p356	79,028,855
25	Total General & Common		(Line 23 + 24)	192,102,762
26	Wage & Salary Allocation Factor		(Line 5)	5.91227%
27	**General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**11,357,633**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	**0**
29	**TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**925,592,703**
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 297,345,764
31	Accumulated General Depreciation		p219.28.c	$ 31,674,420
32	Accumulated Intangible Amortization		(Line 10)	23,288,342
33	Accumulated Common Amortization - Electric		(Line 11)	17,196,214
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	45,575,480
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	117,734,456
36	Wage & Salary Allocation Factor		(Line 5)	5.91227%
37	**General & Common Allocated to Transmission**		(Line 35 * 36)	**6,960,779**
38	**TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**304,306,543**
39	**TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**621,286,161**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
40	ADIT net of FASB 106 and 109		Attachment 1	-179,727,377
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative (Notes A & I)	p266.h	-4,081,414
42	Net Plant Allocation Factor		(Line 18)	35.82%
43	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 41 * 42) + Line 40	**-181,189,190**
43a	**Transmission Related CWIP (Current Year 12 Month weighted average balances)**	(Note B)	p216.43.b as Shown on Attachment 6	6,023,318
43b	**Unamortized Abandoned Transmission Plant**		Attachment 5	30,704,751
	Transmission O&M Reserves			
44	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**-2,847,158**
	Prepayments			
45	Prepayments	(Note A)	Attachment 5	12,467,374
46	**Total Prepayments Allocated to Transmission**		(Line 45)	**12,467,374**
	Materials and Supplies			
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 2,350,979
48	Wage & Salary Allocation Factor		(Line 5)	5.912%
49	Total Transmission Allocated		(Line 47 * 48)	138,996
50	Transmission Materials & Supplies		p227.8c	1,791,003
51	**Total Materials & Supplies Allocated to Transmission**		(Line 49 + 50)	**1,929,999**
	Cash Working Capital			
52	Operation & Maintenance Expense		(Line 85)	15,749,540
53	1/8th Rule		x 1/8	12.5%
54	**Total Cash Working Capital Allocated to Transmission**		(Line 52 * 53)	**1,968,692**
	Network Credits			
55	Outstanding Network Credits	(Note N)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0
57	Net Outstanding Credits		(Line 55 - 56)	**0**
58	**TOTAL Adjustment to Rate Base**		(Line 43 + 43a + 44 + 46 + 51 + 54 - 57)	**-130,942,214**
59	**Rate Base**		(Line 39 + 58)	**490,343,947**

	O&M				
	Transmission O&M				
60	Transmission O&M			p321.112.b	$ 12,089,879
61	Less extraordinary property loss			Attachment 5	$ -
62	Plus amortized extraordinary property loss			Attachment 5	$ -
63	Less Account 565			p321.96.b	$ -
64	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565		(Note O)	PJM Data	$ -
65	Plus Transmission Lease Payments		(Note A)	p200.3.c	$ -
66	**Transmission O&M**			(Lines 60 - 63 + 64 + 65)	**12,089,879**
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	0
68	Total A&G			p323.197.b	$ 70,650,299
69	Less Property Insurance Account 924			p323.185b	326,399
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	3,327,076
71	Less General Advertising Exp Account 930.1			p323.191b	263,968
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	6,810,752
73	Less EPRI Dues		(Note D)	p352-353	0
74	**General & Common Expenses**			(Lines 67 + 68) - Sum (69 to 73)	59,922,104
75	Wage & Salary Allocation Factor			(Line 5)	5.9123%
76	**General & Common Expenses Allocated to Transmission**			(Line 74 * 75)	**3,542,756**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b	0
78	General Advertising Exp Account 930.1		(Note K)	p323.191b	0
79	Subtotal - Transmission Related			(Line 77 + 78)	**0**
80	Property Insurance Account 924			p323.185b	326,399
81	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
82	Total			(Line 80 + 81)	326,399
83	Net Plant Allocation Factor			(Line 18)	35.82%
84	**A&G Directly Assigned to Transmission**			(Line 82 * 83)	**116,904**
85	**Total Transmission O&M**			**(Line 66 + 76 + 79 + 84)**	**15,749,540**
	Depreciation & Amortization Expense				
	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	**19,981,823**
86a	Amortization of Abandoned Transmission Plant			Attachment 5	6,140,950
87	General Depreciation			p336.10b&c	4,159,139
88	Intangible Amortization		(Note A)	p336.1d&e	28,052
89	Total			(Line 87 + 88)	4,187,191
90	Wage & Salary Allocation Factor			(Line 5)	5.9123%
91	**General Depreciation Allocated to Transmission**			(Line 89 * 90)	**247,558**
92	Common Depreciation - Electric Only		(Note A)	p336.11.b	3,600,154
93	Common Amortization - Electric Only		(Note A)	p356 or p336.11d	0
94	Total			(Line 92 + 93)	3,600,154
95	Wage & Salary Allocation Factor			(Line 5)	5.9123%
96	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 94 * 95)	**212,851**
97	**Total Transmission Depreciation & Amortization**			**(Line 86 + 91 + 96)**	**26,583,182**
	Taxes Other than Income				
98	**Taxes Other than Income**			Attachment 2	**5,705,033**
99	**Total Taxes Other than Income**			**(Line 98)**	**5,705,033**
	Return / Capitalization Calculations				
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	$ 48,827,337
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	48,827,337
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	967,848,052
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	2,177,779
107	**Common Stock**			(Sum Lines 104 to 106)	970,025,831
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,023,320,270
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-14,570,176
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	2,392,696
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,011,142,790
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	970,025,831
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,981,168,621
117	Debt %	Total Long Term Debt		(Line 113 / 116)	51.04%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	48.96%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0483
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J)	Fixed	0.1130
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0246
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0553
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0800**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**39,214,340**

Composite Income Taxes

	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite		(Note I)		8.39%
130	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.45%
132	T/ (1-T)				67.94%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	Attachment 1	-72,425
134	T/(1-T)			(Line 132)	67.94%
135	Net Plant Allocation Factor			(Line 18)	35.8163%
136	**ITC Adjustment Allocated to Transmission**			(Line 133 * (1 + 134) * 135)	**-43,563**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	**18,431,261**
138	**Total Income Taxes**			**(Line 136 + 137)**	**18,387,697**

REVENUE REQUIREMENT

	Summary			
139	Net Property, Plant & Equipment		(Line 39)	621,286,161
140	Adjustment to Rate Base		(Line 58)	-130,942,214
141	**Rate Base**		(Line 59)	**490,343,947**
142	O&M		(Line 85)	15,749,540
143	Depreciation & Amortization		(Line 97)	26,583,182
144	Taxes Other than Income		(Line 99)	5,705,033
145	Investment Return		(Line 127)	39,214,340
146	Income Taxes		(Line 138)	18,387,697
147	**Gross Revenue Requirement**		**(Sum Lines 142 to 146)**	**105,639,793**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	876,609,001
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	876,609,001
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	105,639,793
153	**Adjusted Gross Revenue Requirement**		(Line 151 * 152)	**105,639,793**
	Revenue Credits & Interest on Network Credits			
154	**Revenue Credits**		Attachment 3	7,864,009
155	**Interest on Network Credits**	(Note N)	PJM Data	-
156	**Net Revenue Requirement**		**(Line 153 - 154 + 155)**	**97,775,784**
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	**97,775,784**
158	Net Transmission Plant		(Line 19 - 30)	**579,263,237**
159	Net Plant Carrying Charge		(Line 157 / 158)	**16.8793%**
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	**13.4298%**
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	**3.4858%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	**40,173,746**
163	Increased Return and Taxes		Attachment 4	**61,633,960**
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	**101,807,706**
165	Net Transmission Plant		(Line 19 - 30)	**579,263,237**
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	**17.5754%**
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 163 - 86) / 165	**14.1259%**
168	**Net Revenue Requirement**		(Line 156)	**97,775,784**
169	True-up amount		Attachment 6	**(2,277,000)**
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	**666,488**
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515		Attachment 5	**-**
172	**Net Zonal Revenue Requirement**		(Line 168 - 169 + 171)	**96,165,272**
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	**4,114**
174	Rate ($/MW-Year)		(Line 172 / 173)	**23,375**
175	**Network Service Rate ($/MW/Year)**		**(Line 174)**	**23,375**

Notes

A Electric portion only
B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant
that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected
to be placed in service in the current calendar year that is not included in the PJM Regional Transmission Plan (RTEP) must be separately detailed on Attachment 5.
For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).
C Transmission Portion Only
D All EPRI Annual Membership Dues
E All Regulatory Commission Expenses
F Safety related advertising included in Account 930.1
G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.
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.
Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis-point RTO membership adder as authorized by FERC to become effective on December 1, 2007. Per FERC orders in Docket Nos. ER08-686
and ER08-1423, the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point transmission incentive ROE adder as authorized by FERC to become effective June 1, 2008 and
J November 1, 2008 respectively.
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 and the PJM established billing determinants will not be revised or updated in the annual rate reconciliations per settlement in ER05-515.
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) 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 Transmisison Owner whole on Line 155.
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 in on line 64
P Securitization bonds may be included in the capital structure per settlement in ER05-515.
Q ACE capital structure is initially fixed at 50% common equity and 50% debt per settlement in ER05-515 subject to moratorium provisions in the settlement.
R Per the settlement in ER05-515, the facility credits of $15,000 per month paid to Vineland will increase to $37,500 per month (prorated for partial months)
effective on the date FERC approves the settlement in ER05-515.

END

Delmarva Power & Light Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet Tax Detail

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT-282	-	(550,832,771)	-	
ADIT-283	(6,206,209)	(18,132,457)	(101,533,737)	
ADIT-190	569,696	71,301,721	7,054,204	
Subtotal	(5,636,514)	(497,663,508)	(94,479,533)	
Wages & Salary Allocator			5.9123%	
Gross Plant Allocator		33.85922%		
ADIT	(5,636,514)	(168,504,978)	(5,585,885)	(179,727,377)
Total				

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 111

Amount (2,392,696)

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 ***ADIT-190***	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Merrill Creek Excess Capacity	5,058,286	5,058,286				This represents deferred tax generated as a result of an extraordinary charge deducted for books relating to impaired assets due to the effects of deregulation. For tax purposes, the impairment did not give rise to a tax deduction. Deductions for tax are nondeductable.
Merrill Creek Excess Capacity Contra	(486,643)	(486,643)				This contra account represents an adjustment to the Merrill Creek Excess Capacity deferred tax generated relating to impaired assets due to the effects of deregulation.
Above Market Sales Contracts	(620,266)	(620,266)				This represents deferred tax generated as a result of a book expense related to Energy Trading. For tax purposes, this item did not give rise to a tax deduction. Deductions for tax will be amortized over future periods. Generation related.
Allowance for Doubtful Accounts	3,784,421	3,784,421				Under the Tax Reform Act of 1986, taxpayers were required to switch from the reserve method for bad debts to the specific write-off method. The amounts previously accumulated in a reserve were required to be included in taxable income over a four year period. The reserve method is used for book purposes. Related to all revenues.
Charitable Contributions	(322,258)	(322,258)				PHI's consolidated return is in an NOL situation, therefore, Pepco's charitable contributions are carried forward until such time as PHI is in a taxable income position. For book purposes, the contributions are expensed when incurred. Related to all functions.
DE Tax True Up Adjustment	4,600,862	4,600,862				This represents deferred tax generated as a result of a book reserve related to deregulation of the Energy Business. For tax purposes, this item did not give rise to a tax deduction as it did not meet the "all events" test. Generation related.
DE RATE Reserve- Reg Liability-Loss Contingency on Rate Incre	932,030	932,030				Loss Contingency on Rate Increase-When a regulatory asset/liability is established, books (credits/debits) income, which for tax purposes needs to be reversed along with the associated amortization.
Deferred ITC	2,226,910			2,226,910		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant. These items are removed below.
Environmental Expense	2,304,109	2,304,109				These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for environmental site clean-up expenses. For tax no deduction is permitted until the "all events" test is met, typically when economic performance has occurred.
Reg Liability - FERC Formula Rate Adj	569,696		569,696			When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
REG LIAB - GAS	946,638	946,638				This regulatory liability relates to the estimated amount that DPL will receive from Calpine for the Lost and Unaccounted for Gas(LAUF).The reserve will be reduced for any amount received from Calpine.
Claims Reserve	841,922			841,922		These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for General and Auto liability claims. For tax no deduction is permitted until the "all events" test is met, typically when payment is made.
Merrill Creek - Rent	3,413,936	3,413,936				These deferred taxes are the result of rent being recorded ratably over the life of the lease for book purposes. For tax, rent is deductible when economic performance occurs. This asset is Generation related.
MERRILL CREEK RENT CONTRA	(196,528)	(196,528)				This contra account represents an adjustment to the Merrill Creek Rent deferred tax generated relating to rent deductible for tax purposes upon economic performance.
PJM Member Defaults	2,852			2,852		This relates to the reversal of the accrual that was book for GAAP. During December 2007 two members of PJM were declared in default on their obligations to PJM. These items are not deducatable for tax purposes until paid.
Miscellaneous	(191)	-		(191)		Immaterial timing differences.
Pension And Other Labor Related	8,923,163				8,923,163	Affects company personnel across all functions.
OPEB	10,429,137				10,429,137	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
REGULATORY ASSET CONTRA -DE AMI SAVINGS Total	2,559,334	2,559,334				In 2011, adjustments (reductions) to the balance of the AMI regulatory assets were made to reflect the actual savings realized to date as a result of deploying and activating AMI electric meters in Delaware. For tax purposes this needs to be reversed along with the assocated amortization.
Reg Asset - Storm Costs	(372,066)	(372,066)				A regulatory asset was established for the costs associated with Hurricane Irene in third quarter 2012. For book purposes the costs are expense immediately, while for book purposes the costs are amortized.
REG ASSET - Blue Print for the Future	(7,480,034)			(7,480,034)		When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Reg Liab - DE SOS Energy	1,115,158	1,115,158				Retail SOS, Other
Reg Liab - DE SOS Transmission	1,272,664	1,272,664				Retail SOS, Other
Reg Liab - MD SOS Transmission	876,664	876,664				Retail SOS, Other
Reg - DE SOS Adm	(210,576)	(210,576)				Retail SOS, Other
Federal and State NOL	86,420,472	10,352,259		77,937,172	(1,868,959)	PHI's consolidated return is in an NOL situation, therefore NOLs are carried forward until such time as PHI is in a taxable income position. DPL also has stand alone state taxable losses for 2008 forward. Also includes MD NOL of 6.6M that was created from an amended return.
SFAS 109- Regulatory Liability Electric	14,812,910			14,812,910		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related entirely to plant. These items are removed below.
SFAS 109- Regulatory Liability Gas	782,560	782,560				Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related entirely to plant. These items are removed below.
Subtotal - p234	142,185,162	35,790,585	569,696	88,341,541	17,483,341	
Less FASB 109 Above if not separately removed	17,822,379	782,560	-	17,039,820	-	
Less FASB 106 Above if not separately removed	10,429,137	-	-	-	10,429,137	
Total	113,933,646	35,008,026	569,696	71,301,721	7,054,204	

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
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Delmarva Power & Light Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet Tax Detail

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod Or Other Related*	*Only Transmission*	*Plant*	*Labor*	Justification
FAS 109	(53,042,021)			(53,042,021)		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant. These items are removed below.
Plant Related	(550,832,771)			(550,832,771)		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
Subtotal - p275	(603,874,792)	-	-	(603,874,792)	-	
Less FASB 109 Above if not separately removed	(53,042,021)	-	-	(53,042,021)		
Less FASB 106 Above if not separately removed						
Total	(550,832,771)	-	-	(550,832,771)	-	

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
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Delmarva Power & Light Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet Tax Detail

A *ADIT-283*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G **Justification**
Merger Costs	(6,551,941)	(6,644,742)			92,801	Reflects deferred taxes generated on Delmarva Power & Light Company /Atlantic City Electric Company merger costs deducted for tax purposes. For books these costs were capitalized. Pension related and therefore labor related.
Materials Reserve	(983,425)	(983,425)				This represents deferred tax generated as a result of a deduction taken for amounts set aside in a reserve for book purposes. For tax no deduction is permitted until economic performance takes place. These reserves are related to deregulation of Energy.
Blueprint for the Future	(6,121,709)			(6,121,709)		When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Deferred Fuel	(3,169,286)	(3,169,286)				Difference between actual fuel expense as compared to the fuel expense computed in accordance with fuel adjustment clause formulas as deferred on books. In accordance with Section 162 Ordinary and Necessary Business Expenses and Section 461 Rules for Taxable year of Deduction, fuel costs are deductible in the year incurred for federal tax purposes. Rate surcharges are includible in the taxable year the underlying monthly bill is adjusted. Refunds are deductible in the taxable year that the liability is fixed and economic performance has occurred. These deferred taxes are the result of this book/tax difference. Generation Related.
Deferred Fuel Interest	(239,897)	(239,897)				This represents deferred tax generated as a result of interest income and/or expense accrued on the deferred fuel balance for book purposes. For tax purposes, interest income is recognized when received. Interest expense is deducted for tax when paid. Retail related.
Reacquired Debt	(2,392,696)	(2,392,696)				Reflects the deferred taxes generated as a result of the tax deductions taken for the cost to reacquire debt. For book purposes, these amounts were recorded as an asset in account 189 and are amortized over future periods.
Property Taxes	(4,420,057)	(4,420,057)				For book purposes, certain real estate taxes were expensed. For tax purposes, those taxes were capitalized and are being depreciated. Unregulated related.
Reg Asset- COPCO Acquisition Adjustment	(12,010,749)			(12,010,749)		Amortization of COPCO acquisition adjustment. Beginning unamortized balance $40,456,550.00 represents recovery of the regulatory asset per Docket 9093, Order 81518, refers to MD Docket 8583, Order 71719; offset account 114000 Plant Acq Adj. Amortizing monthly. Fully amortized in 2010.
Reg Asset- Other Reg Assets	(4,580,528)	(4,580,528)				Represents various costs which we are, or will be through a future rate case, getting recovery through rate base.
Reg Asset - FERC Formula Rate Adj	(99,338)		(99,338)			When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Reg Liab - MD SOS Energy	(933,308)	(933,308)				Retail SOS, Other
Reg Liab - MD SOS Transmission	(430,534)	(430,534)				Retail SOS, Other
Reg Liab - Electric Distribution Other	1,590,617	1,590,617				Reclass from G/L accounts 182527 DE SOS Energy due to the new UFA model. Part of DE SOS Energy M-1.
Reg Asset - MD SOS Adm	(697,922)	(697,922)				Retail SOS, Other
Deferred Settlement Cost:Energy Efficiency	(6,327,250)	(6,327,250)				When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Deferred Settlement Cost:Other Reg Asset	(3,986,424)	(3,986,424)				When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Reg Asset - Transmission MAPP	(6,106,871)		(6,106,871)			This Regulatory asset represents MAPP adbaonment cost with no potential future value other than through future rate recovery; they are considered worthless assets for tax purposes as such it is deductible under IRC Section 165(a)as an Abandonment Loss.
Reg Asset - DE SOS Interest	(183,989)	(183,989)				When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization.
Reg Asset - Meters	(6,461,303)	(6,461,303)				When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization. AMI-Distribution Related.
Reg Asset - DSM DLC Program	(4,888,096)	(4,888,096)				For books, Demand Side Management Costs are deferred. For tax these costs are expensed when paid. These deferred taxes are the result of this book/tax difference which is retail in nature.
Wilmington Coal Gas Site Cleanup	49	49				Timing differences related to Gas operations.
Pension/OPEB AND Other Labor Related	(101,626,538)				(101,626,538)	Affects company personnel across all functions.
SFAS 109- Regulatory Asset Electric	(30,059,850)			(30,059,850)		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant. These items are removed below.
SFAS 109- Regulatory Asset Gas	2,990	2,990		-		Pursuant to the requirements of FAS 109, DPL's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant. These items are removed below.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(200,678,053)	(44,745,799)	(6,206,209)	(48,192,307)	(101,533,737)	
Less FASB 109 Above if not separately removed	(30,056,860)	2,990	-	(30,059,850)	-	
Less FASB 106 Above if not separately removed	-				-	
Total	(170,621,193)	(44,748,790)	(6,206,209)	(18,132,457)	(101,533,737)	

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
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Delmarva Power & Light Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet Tax Detail

ADITC-255

	Item		Balance	Amortization	
Rate Base Treatment					
Balance to line 41 of Appendix A	Total		4,081,414	548,356	Post 1980
Amortization					
Amortization to line 133 of Appendix A	Total		760,339	72,425	Pre 1981
Total			4,841,753	620,781	
Total Form No. 1 (p 266 & 267)			4,841,753	620,781	
Difference /1			-	-	

/1 Difference must be zero

Delmarva Power & Light Company

Attachment 2 - Taxes Other Than Income Worksheet

Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
Plant Related		***Gross Plant Allocator***	
1 Real property (State, Municipal or Local)	**16,347,755**		
2 Personal property	**-**		
3 Federal/State Excise	**(1,301)**		
4			
5			
6			
Total Plant Related	16,346,455	33.8592%	5,534,782
Labor Related		***Wages & Salary Allocator***	
7 Federal FICA & Unemployment	**2,636,527**		
8 Unemployment	**131,724**		
9			
10			
11			
Total Labor Related	2,768,251	5.9123%	163,666
Other Included		***Gross Plant Allocator***	
12 Miscellaneous	19,448		
13			
14			
Total Other Included	19,448	33.8592%	6,585
Total Included	19,134,153		5,705,033
Excluded			
15 State Franchise Tax	**5,960,785**		
16 Gross Receipts			
17 Sales and Use	**685,363**		
18 Utility Tax for Delmarva	**5,776,598**		
19 City License	**4,031**		
20			
21 Total "Other" Taxes (included on p. 263)	31,560,930		
22 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	31,560,930		
23 Difference	-		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be 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

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Delmarva Power & Light Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		1,736,154
2	Total Rent Revenues	(Sum Line 1)	1,736,154
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 1,435,872
4	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) (Note 4)		-
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		1,406,114
6	PJM Transitional Revenue Neutrality (Note 1)		
7	PJM Transitional Market Expansion (Note 1)		-
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		4,505,121
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	9,083,261
12	Less line 17g		(1,219,252)
13	Total Revenue Credits		7,864,009

Revenue Adjustment to determine Revenue Credit

14	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 173 of Appendix A.	
15	Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, he 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 he Rates.	
16	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). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, 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).	
17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	1,736,154
17b	Costs associated with revenues in line 17a	702,349
17c	Net Revenues (17a - 17b)	1,033,805
17d	50% Share of Net Revenues (17c / 2)	516,903
17e	Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula imes the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.	-
17f	Net Revenue Credit (17d + 17e)	516,903
17g	Line 17f less line 17a	(1,219,252)
18	Note 4: If the facilities associated with he revenues are not included in the formula, the revenue is shown here but not included in the total above and is 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.	12,274,763
19	Amount offset in line 4 above	88,510,946
20	Total Account 454, 456 and 456.1	109,868,970
21	Note 4: SECA revenues booked in Account 447.	

Delmarva Power & Light Company

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 127 + Line 138)	61,633,960
B		100 Basis Point increase in ROE			1.00%

Return Calculation

59	Rate Base			(Line 39 + 58)	490,343,947
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	48,827,337
101	Less LTD Interest on Securitization Bonds			Attachment 8	0
102	**Long Term Interest**			"(Line 100 - line 101)"	48,827,337
103	**Preferred Dividends**		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	967,848,052
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	2,177,779
107	**Common Stock**			(Sum Lines 104 to 106)	970,025,831
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,023,320,270
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-14,570,176
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	2,392,696
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,011,142,790
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	970,025,831
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,981,168,621
117	Debt %	Total Long Term Debt		(Line 113 / 116)	51.04%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0.00%
119	Common %	Common Stock		(Line 115 / 116)	48.96%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0483
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J from Appendix A)	Appendix A % plus 100 Basis Pts	0.1230
123	Weighted Cost o	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0246
124	Weighted Cost o	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost o	Common Stock		(Line 119 * 122)	0.0602
126	**Total Return (R)**			(Sum Lines 123 to 125)	**0.0849**
127	**Investment Return = Rate Base * Rate of Return**			**(Line 59 * 126)**	**41,615,177**

Composite Income Taxes

	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite				8.39%
130	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.45%
132	T/ (1-T)				67.94%
	ITC Adjustment				
133	Amortized Investment Tax Credit		enter negative	Attachment 1	(72,425)
134	T/(1-T)			(Line 132)	68%
135	Net Plant Allocation Factor			(Line 18)	35.8163%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-43,563**
137	**Income Tax Component =**		CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		**20,062,346**
138	**Total Income Taxes**			**(Line 136 + 137)**	**20,018,782**

Delmarva Power & Light Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	45,657,729	23,255,705	22,402,024	See Form 1
11	Accumulated Common Amortization - Electric	(Note A)	p356	20,471,683	17,196,214	3,275,469	See Form 1
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	54,105,401	45,448,537	8,656,864	See Form 1
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	91,855,671	77,158,765	14,696,906	See Form 1
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	6,008,320	5,462,534	545,786	See Form 1
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	2,432,089	2,350,979	81,110	96.67% Electric, 3.33% Non-Electric
	Allocated General & Common Expenses						
65	Plus Transmission Lease Payments	(Note A)	p200.3.c				
67	Common Plant O&M	(Note A)	p356	0	0	0	
	Depreciation Expense						
88	Intangible Amortization	(Note A)	p336.1d&e	73,251	73,251	0	See FERC Form 2, Page 337, Line 1, Column h for non-electric portion.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	4,112,707	3,454,673	658,034	See Form 1, electric only.
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0	0	0	See Form 1, electric only.

Transmission / Non-transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	25,109,992	0	25,109,992	Specific identification based on plant records: The following plant investments are included:
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.160b	3,648,587	0	3,648,587	Enter Details
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	2,360,078,036	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	788,257,764	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	77,158,765	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	285,184,073	0	0	See Form 1

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	-	-	See Form 1

Delmarva Power & Light Company

Attachment 5 - Cost Support

Regulatory Expense Related to Transmission Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$ 3,648,587	0	3,648,587	FERC related.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	3,648,587	0	3,648,587	FERC related

Safety Related Advertising Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	159,418	0	159,418	None

MultiState Workpaper

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Rate	State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				MD	PA	VA	DE	OH	Enter Calculation
129	SIT=State Income Tax Rate or Composite	(Note I)	8.39%	8.25%	9.990%	6%	8.7%	5.10%	Apportioned: PA 0.0089%, VA 0.1757%, DE 5.8801%, MD 2.3239%, OH 0.0014%, NY 0.0012%

Education and Out Reach Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	159,418	0	159,418	None

Excluded Plant Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Note	Reference	Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities					
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0	General Description of the Facilities
	Instructions:				Enter $	None
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,				Or	
	the following formula will be used:	Example			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

Delmarva Power & Light Company

Attachment 5 - Cost Support

Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Outstanding Network Credits	Description of the Credits
	Network Credits			Enter $	
55	Outstanding Network Credits	(Note N)	From PJM	0	General Description of the Credits
					None
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0	
					None
					Add more lines if necessary

Transmission Related Account 242 Reserves

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Total	Allocation	Transmission Related	Details
44	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)	Enter $		Amount	
	Directly Assignable to Transmission	-	100%	-	
	Labor Related, General plant related or Common Plant related	38,440,401	5.912%	2,272,700	
	Plant Related	1,696,608	33.859%	574,458	
	Other		0.00%	-	
	Total Transmission Related Reserves	40,137,009		2,847,158	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45	Prepayments					
				Allocator	To Line 45	
	Pension Liabilities, if any, in Account 242		-	4.966%	-	
	Prepayments	$	19,375,443	4.966%	962,244	
	Prepaid Pensions if not included in Prepayments	$	231,663,711	4.966%	11,505,130	
			251,039,154	4.97%	12,467,374	
5	Wages & Salary Allocator		5.912%			
	Electric vs Gas		84%	Based on Modified Wisconsin Method		
	Modified Wages & Salaries Allocator		4.966%			Add more lines if necessary

Extraordinary Property Loss

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Amount	Number of years	Amortization	w/ interest
61	Less extraordinary property loss	Attachment 5	$ -			
62	Plus amortized extraordinary property loss	Attachment 5		5	$ -	$ -

Delmarva Power & Light Company

Attachment 5 - Cost Support

Interest on Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Interest on Network Credits	Description of the Interest on the Credits
	Revenue Credits & Interest on Network Credits				
155	Interest on Network Credits	(Note N)	PJM Data	0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Amount	Description & PJM Documentation
	Net Revenue Requirement			
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515	Attachment 5	-	

PJM Load Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
173	1 CP Peak	(Note L)	PJM Data	4,114.1	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
DPL zone						
Total						

Abandoned Transmission Plant

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions							
			Project	MAPP Abandonment			Total
			FERC Order	ER13-607	ER13-607	Total	
A	Total Balance of Unamortized Abandoned Plant		Per FERC Order	36,139,908	1,411,586	37,551,494	
B	Percentage allowed by FERC Order		Per FERC Order	100%	50%		
C	Beginning Balance of Allowed Unamortized Abandoned Plant		A*B	36,139,908	705,793	36,845,701	
D	Months Remaining in Amortization Period			60	60		
E	Months in Year to be Amortized		# Months	10	10		
F	Amortization in Rate Year	to 86a in Attachment H	C/D*E	6,023,318	117,632	6,140,950	
G	Additions (Deductions)		Worksheet	-	-	-	
H	End of Year Balance in Unamortized Transmission Plant	to 43b in Attachment H	C-F+G	30,116,590	588,161	30,704,751	

Line G deduction include proceeds from the sale of abanded assets , land, or land rights

Delmarva Power & Light Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 10,319,368	$ 8,778,179	$ 19,411,471	$ 4,732,311	$ 43,241,329
Procurement & Administrative Services	6,800,125	5,117,604	11,142,880	1,168,548	24,229,157
Financial Services & Corporate Expenses	13,119,301	10,095,632	19,784,530	2,113,560	45,113,024
Insurance Coverage and Services	2,722,299	2,318,184	3,992,693	1,182,610	10,215,785
Human Resources	4,842,098	3,325,597	7,918,949	1,098,248	17,184,892
Legal Services	3,696,208	2,776,662	6,956,240	521,371	13,950,480
Audit Services	889,689	686,619	1,654,755	194,081	3,425,144
Customer Services	50,035,762	39,174,928	27,817,940	9,258	117,037,888
Utility Marketing Services	366,622	328,711	630,571	-	1,325,904
Information Technology	16,578,099	12,158,126	38,724,477	419,276	67,879,979
External Affairs	2,615,303	2,177,747	5,210,186	465,886	10,469,122
Environmental Services	1,360,579	1,119,104	1,973,001	148,481	4,601,165
Safety Services	388,220	368,439	633,768	-	1,390,427
Regulated Electric & Gas Delivery	27,135,040	20,392,061	40,410,791	1,086	87,938,979
Energy Business	-	-	-	3,902	3,902
Internal Consulting Services	236,486	183,469	712,652	-	1,132,607
Interns	80,850	40,490	165,202	-	286,541
Cost of Benefits	11,931,169	7,425,942	18,880,059	3,008,206	41,245,375
Building Services	8,336	94,433	4,845,257	-	4,948,027
Total	$153,125,554	$116,561,926	$ 210,865,421	$ 15,066,825	$ 495,619,726

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2012

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Potomac Electric Power Company	66,537,297	144,074,045	254,079	210,865,421
2	Delmarva Power & Light Company	39,129,111	113,813,964	182,479	153,125,554
3	Atlantic City Electric Company	24,278,507	92,144,935	138,484	116,561,926
4	Pepco Energy Services, Inc.	3,241,220	8,643,664	15,330	11,900,214
5	Conectiv, LLC	51,957	790,021	2,094	844,072
6	Potomac Capital Investment Corporation	247,670	319,705	904	568,279
7	Thermal Energy Limited Partnership	19,186	526,060	716	545,962
8	ATS Operating Services, Inc.	141	273,158	312	273,611
9	Atlantic Southern Properties, Inc.	18,351	243,366	390	262,107
10	Conectiv Energy Supply, Inc.	39,953	147,691	1,059	188,703
11	Pepco Holdings, Inc.	112,705	64,916	499	178,120
12	Conectiv Properties and Investment, Inc.	36,456	132,037	221	168,714
13	Conectiv Thermal Systems, Inc.	5,562	93,841	115	99,518
14	Conectiv Communications, Inc.	95	11,553	20	11,668
15	Atlantic City Electric Transition Funding, LLC	4,111	2,728	4	6,843
16	Conectiv North East, LLC	256	4,953	8	5,217
17	Delaware Operating Services Company	235	4,943	4	5,182
18	ATE Investment, Inc.	2,954	1,042	8	4,004
19	Atlantic Generation, Inc.	180	2,567	4	2,751
20	Conectiv Services II, Inc.	41	1,473	13	1,527
21	Conectiv Solutions LLC	313	18	1	332
22	Atlantic Jersey Thermal Systems, Inc.		1		1
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	133,726,301	361,296,681	596,744	495,619,726

Delmarva Power & Light Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconc liation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)

78,930,003 Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan			35,043,048		11.5	-	-	402,995,052	-	-	-	33,582,921	-	
Feb			88,851		10.5	-	-	932,936	-	-	-	77,745	-	
Mar			107,200		9.5	-	-	1,018,400	-	-	-	84,867	-	
Apr			25,046		8.5	-	-	212,891	-	-	-	17,741	-	
May			25,046		7.5	-	-	187,845	-	-	-	15,654	-	
Jun	25,192,821		25,046		6.5	163,753,337	-	162,799	-	13,646,111	-	13,567	-	
Jul			26,546		5.5	-	-	146,003	-	-	-	12,167	-	
Aug			2,520,046		4.5	-	-	11,340,207	-	-	-	945,017	-	
Sep			21,546		3.5	-	-	75,411	-	-	-	6,284	-	
Oct			20,046		2.5	-	-	50,115	-	-	-	4,176	-	
Nov			20,046		1.5	-	-	30,069	-	-	-	2,506	-	
Dec	16,372,433		20,046		0.5	8,186,217	-	10,023	-	682,185	-	835	-	
Total	41,565,254	-	37,942,513	-		171,939,553	-	-	-	14,328,296	-	34,763,479	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										14,328,296	-	34,763,479	-	
								Input to Line 21 of Appendix A		14,328,296	-		-	14,328,296
								Input to Line 43a of Appendix A				34,763,479		34,763,479
								Month In Service or Month for CWIP		7.86	#DIV/0!	1.01	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 14,328,296 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

84,738,678 — Must run Appendix A to get this number (with inputs on lines 21 and 43a of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)

$ 84,738,678

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

84,455,511 Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2
For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 93,540,395 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan	10,084,112		35,043,048		11.5	115,967,290	-	402,995,052	-	9,663,941	-	33,582,921	-	
Feb	815,835		88,851		10.5	8,566,270	-	932,936	-	713,856	-	77,745	-	
Mar	1,307,542		107,199		9.5	12,421,647	-	1,018,391	-	1,035,137	-	84,866	-	
Apr	9,560,201		228,924		8.5	81,261,708	-	1,945,854	-	6,771,809	-	162,155	-	
May	1,323,045		48,875		7.5	9,922,834	-	366,563	-	826,903	-	30,547	-	
Jun	9,538,766		(18,199)		6.5	62,001,980	-	(118,294)	-	5,166,832	-	(9,858)	-	
Jul	1,652,263		12,677		5.5	9,087,448	-	69,724	-	757,287	-	5,810	-	
Aug	14,511,849		(115,325)		4.5	65,303,321	-	(518,963)	-	5,441,943	-	(43,247)	-	
Sep	4,715,828		191,011		3.5	16,505,399	-	668,539	-	1,375,450	-	55,712	-	
Oct	6,019,176		552,847		2.5	15,047,940	-	1,382,117	-	1,253,995	-	115,176	-	
Nov	7,605,085		-		1.5	11,407,627	-	-	-	950,636	-	-	-	
Dec	26,406,693		-		0.5	13,203,346	-	-	-	1,100,279	-	-	-	
Total	93,540,395	-	36,139,908	-		420,696,810	-	-	-	35,058,068	-	34,061,826	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										35,058,068	-	34,061,826	-	
								Input to Line 21 of Appendix A		35,058,068	-		-	35,058,068
								Input to Line 43a of Appendix A				34,061,826		34,061,826
								Month In Service or Month for CWIP		7.50	#DIV/0!	0.69	#DIV/0!	

82,499,503 Result of Formula for Reconciliation Must run Appendix A with cap adds in line 21 & line 20
(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan			36,139,908		11.5	-	-	415,608,938	-	-	-	34,634,078	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar			(36,139,908)		9.5	-	-	(343,329,123)	-	-	-	(28,610,760)	-	
Apr	16,467,349				8.5	139,972,470	-	-	-	11,664,373	-	-	-	
May	8,824,256				7.5	66,181,920	-	-	-	5,515,160	-	-	-	
Jun	37,674,034				6.5	244,881,224	-	-	-	20,406,769	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov	318,141				1.5	477,212	-	-	-	39,768	-	-	-	
Dec	-				0.5	-	-	-	-	-	-	-	-	
Total	63,283,781	-	-	-		451,512,826	-	-	-	37,626,069	-	6,023,318	-	
New Transmission Plant Additions and CWIP (weighted by months in service)								0		37,626,069	-	6,023,318	-	
98,442,272								Input to Line 21 of Appendix A		37,626,069	-		-	37,626,069
								Input to Line 43a of Appendix A				6,023,318		6,023,318
								Month In Service or Month for CWIP		4.87	#DIV/0!	#DIV/0!	#DIV/0!	

9 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 7		The forecast in Prior Year		
82,499,503	-	84,698,652	=	(2,199,149)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March o 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(183,262)	0.2800%	11.5	(5,901)	(189,163)
Jul	Year 1	(183,262)	0.2800%	10.5	(5,388)	(188,650)
Aug	Year 1	(183,262)	0.2800%	9.5	(4,875)	(188,137)
Sep	Year 1	(183,262)	0.2800%	8.5	(4,362)	(187,624)
Oct	Year 1	(183,262)	0.2800%	7.5	(3,849)	(187,111)
Nov	Year 1	(183,262)	0.2800%	6.5	(3,335)	(186,598)
Dec	Year 1	(183,262)	0.2800%	5.5	(2,822)	(186,085)
Jan	Year 2	(183,262)	0.2800%	4.5	(2,309)	(185,572)
Feb	Year 2	(183,262)	0.2800%	3.5	(1,796)	(185,058)
Mar	Year 2	(183,262)	0.2800%	2.5	(1,283)	(184,545)
Apr	Year 2	(183,262)	0.2800%	1.5	(770)	(184,032)
May	Year 2	(183,262)	0.2800%	0.5	(257)	(183,519)
Total		(2,199,149)				(2,236,095)

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(2,236,095)	0.2800%	(189,750)	(2,052,606)
Jul	Year 2	(2,052,606)	0.2800%	(189,750)	(1,868,603)
Aug	Year 2	(1,868,603)	0.2800%	(189,750)	(1,684,085)
Sep	Year 2	(1,684,085)	0.2800%	(189,750)	(1,499,050)
Oct	Year 2	(1,499,050)	0.2800%	(189,750)	(1,313,498)
Nov	Year 2	(1,313,498)	0.2800%	(189,750)	(1,127,426)
Dec	Year 2	(1,127,426)	0.2800%	(189,750)	(940,832)
Jan	Year 3	(940,832)	0.2800%	(189,750)	(753,717)
Feb	Year 3	(753,717)	0.2800%	(189,750)	(566,077)
Mar	Year 3	(566,077)	0.2800%	(189,750)	(377,912)
Apr	Year 3	(377,912)	0.2800%	(189,750)	(189,220)
May	Year 3	(189,220)	0.2800%	(189,750)	-
Total with interest				(2,277,000)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	(2,277,000)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 98,442,272
Revenue Requirement for Year 3	96,165,272

10 May Year 3 Post results of Step 9 on PJM web site

$ 96,165,272 Post results of Step 3 on PJM web site

11 June Year 3 Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 96,165,272

Delmarva Power & Light Company

Attachment 7 - Transmission Enhancement Charge Worksheet

Line					
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if not a CIAC**				
3			Formula Line		
4		A	160	Net Plant Carrying Charge without Depreciation	13.430%
5		B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	14.126%
6		C		Line B less Line A	0.6960%
7	**FCR if a CIAC**				
8		D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	3.4858%
9	**The FCR resulting from Formula in a given year is used for that year only.**				
10	**Therefore actual revenues collected in a year do not change based on cost data for subsequent years**				
11	**Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis point RTO membership adder as authorized by FER**				

Line	Description	Details		B0512 MAPP		B0512 MAPP Abandoned Plant	
12	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes		Yes	
13	Useful life of project	Life		35		5	
14	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 18, Otherwise "No"	CIAC	(Yes or No)	No		No	
15	Input the allowed ROE Incentive	Increased ROE (Basis Points)		150		-50	
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		13.4298%		13.4298%	
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		14.4739%		13.0818%	
18	Columns A, B or C from Attachment 6	Investment		36,139,908	may be weighted average of small projects	36,845,701	may be weighted average of small projects
19	Line 18 divided by line 13	Annual Depreciation Exp		1,032,569		7,369,140	
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		1.00		3.00	

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
31	Base FCR	2013	36,139,908	-	36,139,908	808,920	36,845,701	6,140,950	30,704,751	9,577,275
32	W Increased ROE	2013	36,139,908	-	36,139,908	871,808	36,845,701	6,140,950	30,704,751	9,488,226
33	Base FCR	2014					30,704,751	7,369,140	23,335,611	10,503,069
34	W Increased ROE	2014					30,704,751	7,369,140	23,335,611	10,421,856
35	Base FCR	2015					23,335,611	7,369,140	15,966,470	9,513,407
36	W Increased ROE	2015					23,335,611	7,369,140	15,966,470	9,457,840
37	Base FCR	2016					15,966,470	7,369,140	8,597,330	8,523,745
38	W Increased ROE	2016					15,966,470	7,369,140	8,597,330	8,493,825
39	Base FCR	2017					8,597,330	7,369,140	1,228,190	7,534,084
40	W Increased ROE	2017					8,597,330	7,369,140	1,228,190	7,529,809
41	Base FCR	2018					1,228,190	1,228,190	-	1,228,190
42	W Increased ROE	2018					1,228,190	1,228,190	-	1,228,190
43	Base FCR	2019								
44	W Increased ROE	2019								
45	Base FCR	2020								
46	W Increased ROE	2020								
47	Base FCR	2021								
48	W Increased ROE	2021								
49	Base FCR	2022								
50	W Increased ROE	2022								
51	Base FCR	2023								
52	W Increased ROE	2023								
53	Base FCR	2024								
54	W Increased ROE	2024								
55	Base FCR	2025								
56	W Increased ROE	2025								
57	Base FCR	2026								
58	W Increased ROE	2026								
59	Base FCR	2027								
60	W Increased ROE	2027								
61		....		....	.....	....		....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....
63										

C to become effecitve on December 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE for specific projects identified or to be indentified in Attachn

B0241.3 Red Lion sub reconfiguration	B0494.1-4 Red Lion-Keeney	B0241.1-.2 Red Lion-Keeney
Yes	No	No
35	35	35
No	No	No
150	150	150
13.4298%	13.4298%	13.4298%
14.4739%	14.4739%	14.4739%
14,689,101	3,099,104	2,418,717
419,689	88,546	69,106
6.00	6.00	6.00

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
13,220,191	419,689	12,800,502	2,138,772	2,789,194	88,546	2,700,648	451,238	2,176,845	69,106	2,107,739	352,172
13,220,191	419,689	12,800,502	2,272,417	2,789,194	88,546	2,700,648	479,434	2,176,845	69,106	2,107,739	374,178
12,800,502	419,689	12,380,814	2,082,409	2,700,648	88,546	2,612,102	439,346	2,107,739	69,106	2,038,633	342,891
12,800,502	419,689	12,380,814	2,211,672	2,700,648	88,546	2,612,102	466,618	2,107,739	69,106	2,038,633	364,175
12,380,814	419,689	11,961,125	2,026,045	2,612,102	88,546	2,523,556	427,455	2,038,633	69,106	1,969,527	333,610
12,380,814	419,689	11,961,125	2,150,927	2,612,102	88,546	2,523,556	453,802	2,038,633	69,106	1,969,527	354,173
11,961,125	419,689	11,541,437	1,969,682	2,523,556	88,546	2,435,010	415,563	1,969,527	69,106	1,900,421	324,329
11,961,125	419,689	11,541,437	2,090,182	2,523,556	88,546	2,435,010	440,986	1,969,527	69,106	1,900,421	344,171
11,541,437	419,689	11,121,748	1,913,318	2,435,010	88,546	2,346,464	403,672	1,900,421	69,106	1,831,314	315,048
11,541,437	419,689	11,121,748	2,029,437	2,435,010	88,546	2,346,464	428,170	1,900,421	69,106	1,831,314	334,168
11,121,748	419,689	10,702,059	1,856,955	2,346,464	88,546	2,257,919	391,780	1,831,314	69,106	1,762,208	305,767
11,121,748	419,689	10,702,059	1,968,691	2,346,464	88,546	2,257,919	415,354	1,831,314	69,106	1,762,208	324,166
10,702,059	419,689	10,282,371	1,800,592	2,257,919	88,546	2,169,373	379,889	1,762,208	69,106	1,693,102	296,487
10,702,059	419,689	10,282,371	1,907,946	2,257,919	88,546	2,169,373	402,538	1,762,208	69,106	1,693,102	314,164
10,282,371	419,689	9,862,682	1,744,228	2,169,373	88,546	2,080,827	367,997	1,693,102	69,106	1,623,996	287,206
10,282,371	419,689	9,862,682	1,847,201	2,169,373	88,546	2,080,827	389,722	1,693,102	69,106	1,623,996	304,161
9,862,682	419,689	9,442,994	1,687,865	2,080,827	88,546	1,992,281	356,105	1,623,996	69,106	1,554,890	277,925
9,862,682	419,689	9,442,994	1,786,456	2,080,827	88,546	1,992,281	376,906	1,623,996	69,106	1,554,890	294,159
9,442,994	419,689	9,023,305	1,631,501	1,992,281	88,546	1,903,735	344,214	1,554,890	69,106	1,485,783	268,644
9,442,994	419,689	9,023,305	1,725,711	1,992,281	88,546	1,903,735	364,090	1,554,890	69,106	1,485,783	284,157
9,023,305	419,689	8,603,616	1,575,138	1,903,735	88,546	1,815,189	332,322	1,485,783	69,106	1,416,677	259,363
9,023,305	419,689	8,603,616	1,664,965	1,903,735	88,546	1,815,189	351,274	1,485,783	69,106	1,416,677	274,154
8,603,616	419,689	8,183,928	1,518,775	1,815,189	88,546	1,726,644	320,431	1,416,677	69,106	1,347,571	250,082
8,603,616	419,689	8,183,928	1,604,220	1,815,189	88,546	1,726,644	338,458	1,416,677	69,106	1,347,571	264,152
8,183,928	419,689	7,764,239	1,462,411	1,726,644	88,546	1,638,098	308,539	1,347,571	69,106	1,278,465	240,802
8,183,928	419,689	7,764,239	1,543,475	1,726,644	88,546	1,638,098	325,642	1,347,571	69,106	1,278,465	254,150
7,764,239	419,689	7,344,551	1,406,048	1,638,098	88,546	1,549,552	296,648	1,278,465	69,106	1,209,359	231,521
7,764,239	419,689	7,344,551	1,482,730	1,638,098	88,546	1,549,552	312,826	1,278,465	69,106	1,209,359	244,147
7,344,551	419,689	6,924,862	1,349,684	1,549,552	88,546	1,461,006	284,756	1,209,359	69,106	1,140,252	222,240
7,344,551	419,689	6,924,862	1,421,985	1,549,552	88,546	1,461,006	300,010	1,209,359	69,106	1,140,252	234,145
....	....	.....	....	....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

ıent 7 is 12.80%, which includes a 150 basis-point tranmission incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November 1, 20(

B0567 Mt.Pleasant-Townsend				B0483.1-.3 Oak Hall-Wattsville				B0320 Cool Springs			
No				No				No			
35				35				35			
No				No				No			
150				150				150			
13.4298%				13.4298%				13.4298%			
14.4739%				14.4739%				14.4739%			
6,414,723				8,379,558				14,504,530			
183,278				239,416				414,415			
6				12				9			
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
5,956,529	183,278	5,773,251	958,614	7,900,726	239,416	7,661,310	1,268,315	13,572,096	414,415	13,157,681	2,181,467
5,956,529	183,278	5,773,251	1,018,891	7,900,726	239,416	7,661,310	1,348,304	13,572,096	414,415	13,157,681	2,318,842
5,773,251	183,278	5,589,973	934,001	7,661,310	239,416	7,421,894	1,236,162	13,157,681	414,415	12,743,266	2,125,812
5,773,251	183,278	5,589,973	992,364	7,661,310	239,416	7,421,894	1,313,652	13,157,681	414,415	12,743,266	2,258,860
5,589,973	183,278	5,406,695	909,387	7,421,894	239,416	7,182,478	1,204,009	12,743,266	414,415	12,328,851	2,070,157
5,589,973	183,278	5,406,695	965,836	7,421,894	239,416	7,182,478	1,278,999	12,743,266	414,415	12,328,851	2,198,878
5,406,695	183,278	5,223,417	884,773	7,182,478	239,416	6,943,062	1,171,856	12,328,851	414,415	11,914,435	2,014,501
5,406,695	183,278	5,223,417	939,309	7,182,478	239,416	6,943,062	1,244,346	12,328,851	414,415	11,914,435	2,138,896
5,223,417	183,278	5,040,140	860,159	6,943,062	239,416	6,703,646	1,139,703	11,914,435	414,415	11,500,020	1,958,846
5,223,417	183,278	5,040,140	912,781	6,943,062	239,416	6,703,646	1,209,693	11,914,435	414,415	11,500,020	2,078,914
5,040,140	183,278	4,856,862	835,545	6,703,646	239,416	6,464,230	1,107,550	11,500,020	414,415	11,085,605	1,903,191
5,040,140	183,278	4,856,862	886,254	6,703,646	239,416	6,464,230	1,175,041	11,500,020	414,415	11,085,605	2,018,932
4,856,862	183,278	4,673,584	810,931	6,464,230	239,416	6,224,815	1,075,397	11,085,605	414,415	10,671,190	1,847,536
4,856,862	183,278	4,673,584	859,727	6,464,230	239,416	6,224,815	1,140,388	11,085,605	414,415	10,671,190	1,958,950
4,673,584	183,278	4,490,306	786,317	6,224,815	239,416	5,985,399	1,043,244	10,671,190	414,415	10,256,775	1,791,881
4,673,584	183,278	4,490,306	833,199	6,224,815	239,416	5,985,399	1,105,735	10,671,190	414,415	10,256,775	1,898,968
4,490,306	183,278	4,307,028	761,704	5,985,399	239,416	5,745,983	1,011,091	10,256,775	414,415	9,842,360	1,736,225
4,490,306	183,278	4,307,028	806,672	5,985,399	239,416	5,745,983	1,071,082	10,256,775	414,415	9,842,360	1,838,986
4,307,028	183,278	4,123,751	737,090	5,745,983	239,416	5,506,567	978,937	9,842,360	414,415	9,427,944	1,680,570
4,307,028	183,278	4,123,751	780,144	5,745,983	239,416	5,506,567	1,036,430	9,842,360	414,415	9,427,944	1,779,004
4,123,751	183,278	3,940,473	712,476	5,506,567	239,416	5,267,151	946,784	9,427,944	414,415	9,013,529	1,624,915
4,123,751	183,278	3,940,473	753,617	5,506,567	239,416	5,267,151	1,001,777	9,427,944	414,415	9,013,529	1,719,022
3,940,473	183,278	3,757,195	687,862	5,267,151	239,416	5,027,735	914,631	9,013,529	414,415	8,599,114	1,569,260
3,940,473	183,278	3,757,195	727,090	5,267,151	239,416	5,027,735	967,124	9,013,529	414,415	8,599,114	1,659,040
3,757,195	183,278	3,573,917	663,248	5,027,735	239,416	4,788,319	882,478	8,599,114	414,415	8,184,699	1,513,605
3,757,195	183,278	3,573,917	700,562	5,027,735	239,416	4,788,319	932,471	8,599,114	414,415	8,184,699	1,599,058
3,573,917	183,278	3,390,639	638,634	4,788,319	239,416	4,548,903	850,325	8,184,699	414,415	7,770,284	1,457,950
3,573,917	183,278	3,390,639	674,035	4,788,319	239,416	4,548,903	897,819	8,184,699	414,415	7,770,284	1,539,076
3,390,639	183,278	3,207,362	614,020	4,548,903	239,416	4,309,487	818,172	7,770,284	414,415	7,355,869	1,402,294
3,390,639	183,278	3,207,362	647,507	4,548,903	239,416	4,309,487	863,166	7,770,284	414,415	7,355,869	1,479,094
....	....	.....	....	....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

8 respectively.

BO568 3rd Indian River	BO272.1 Keeney 500kV Sub	BO751 Keeney - Additional Breakers on 500kV Bus
No	Yes	Yes
35	35	35
No	No	No
150	0	0
13.4298%	13.4298%	13.4298%
14.4739%	13.4298%	13.4298%
6,681,345	217,662	5,055,041
190,896	6,219	144,430
8	6	6

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
6,426,818	190,896	6,235,922	1,028,368	214,553	6,219	208,334	34,198	4,982,826	144,430	4,838,396	794,217
6,426,818	190,896	6,235,922	1,093,475	214,553	6,219	208,334	34,198	4,982,826	144,430	4,838,396	794,217
6,235,922	190,896	6,045,026	1,002,731	208,334	6,219	202,115	33,363	4,838,396	144,430	4,693,967	774,821
6,235,922	190,896	6,045,026	1,065,845	208,334	6,219	202,115	33,363	4,838,396	144,430	4,693,967	774,821
6,045,026	190,896	5,854,131	977,094	202,115	6,219	195,896	32,527	4,693,967	144,430	4,549,537	755,424
6,045,026	190,896	5,854,131	1,038,215	202,115	6,219	195,896	32,527	4,693,967	144,430	4,549,537	755,424
5,854,131	190,896	5,663,235	951,457	195,896	6,219	189,677	31,692	4,549,537	144,430	4,405,107	736,027
5,854,131	190,896	5,663,235	1,010,585	195,896	6,219	189,677	31,692	4,549,537	144,430	4,405,107	736,027
5,663,235	190,896	5,472,340	925,820	189,677	6,219	183,458	30,857	4,405,107	144,430	4,260,677	716,631
5,663,235	190,896	5,472,340	982,955	189,677	6,219	183,458	30,857	4,405,107	144,430	4,260,677	716,631
5,472,340	190,896	5,281,444	900,184	183,458	6,219	177,239	30,022	4,260,677	144,430	4,116,248	697,234
5,472,340	190,896	5,281,444	955,325	183,458	6,219	177,239	30,022	4,260,677	144,430	4,116,248	697,234
5,281,444	190,896	5,090,549	874,547	177,239	6,219	171,020	29,187	4,116,248	144,430	3,971,818	677,837
5,281,444	190,896	5,090,549	927,695	177,239	6,219	171,020	29,187	4,116,248	144,430	3,971,818	677,837
5,090,549	190,896	4,899,653	848,910	171,020	6,219	164,801	28,351	3,971,818	144,430	3,827,388	658,441
5,090,549	190,896	4,899,653	900,065	171,020	6,219	164,801	28,351	3,971,818	144,430	3,827,388	658,441
4,899,653	190,896	4,708,757	823,273	164,801	6,219	158,582	27,516	3,827,388	144,430	3,682,958	639,044
4,899,653	190,896	4,708,757	872,435	164,801	6,219	158,582	27,516	3,827,388	144,430	3,682,958	639,044
4,708,757	190,896	4,517,862	797,636	158,582	6,219	152,363	26,681	3,682,958	144,430	3,538,529	619,647
4,708,757	190,896	4,517,862	844,805	158,582	6,219	152,363	26,681	3,682,958	144,430	3,538,529	619,647
4,517,862	190,896	4,326,966	771,999	152,363	6,219	146,144	25,846	3,538,529	144,430	3,394,099	600,251
4,517,862	190,896	4,326,966	817,175	152,363	6,219	146,144	25,846	3,538,529	144,430	3,394,099	600,251
4,326,966	190,896	4,136,071	746,362	146,144	6,219	139,926	25,011	3,394,099	144,430	3,249,669	580,854
4,326,966	190,896	4,136,071	789,545	146,144	6,219	139,926	25,011	3,394,099	144,430	3,249,669	580,854
4,136,071	190,896	3,945,175	720,725	139,926	6,219	133,707	24,175	3,249,669	144,430	3,105,239	561,458
4,136,071	190,896	3,945,175	761,915	139,926	6,219	133,707	24,175	3,249,669	144,430	3,105,239	561,458
3,945,175	190,896	3,754,280	695,088	133,707	6,219	127,488	23,340	3,105,239	144,430	2,960,810	542,061
3,945,175	190,896	3,754,280	734,285	133,707	6,219	127,488	23,340	3,105,239	144,430	2,960,810	542,061
3,754,280	190,896	3,563,384	669,451	127,488	6,219	121,269	22,505	2,960,810	144,430	2,816,380	522,664
3,754,280	190,896	3,563,384	706,655	127,488	6,219	121,269	22,505	2,960,810	144,430	2,816,380	522,664
....	....	.....	....	....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

BO566 Trappe Tap - Todd	BO733 Harmony Add 2nd 230/138 Auto Tr
No	No
35	35
No	No
150	0
13.4298%	13.4298%
14.4739%	13.4298%
16,372,433	10,567,349
467,784	301,924
12	4

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
16,372,433	467,784	15,904,649	2,603,748	10,567,349	201,283	10,366,066	1,245,390	$ 23,442,695		$ 23,442,695
16,372,433	467,784	15,904,649	2,769,803	10,567,349	201,283	10,366,066	1,245,390	$ 24,109,183	$ 24,109,183	
15,904,649	467,784	15,436,865	2,540,926	10,366,066	301,924	10,064,142	1,653,520	$ 23,669,048		$ 23,669,048
15,904,649	467,784	15,436,865	2,702,097	10,366,066	301,924	10,064,142	1,653,520	$ 24,258,841	$ 24,258,841	
15,436,865	467,784	14,969,082	2,478,103	10,064,142	301,924	9,762,218	1,612,972	$ 22,340,190		$ 22,340,190
15,436,865	467,784	14,969,082	2,634,390	10,064,142	301,924	9,762,218	1,612,972	$ 22,933,984	$ 22,933,984	
14,969,082	467,784	14,501,298	2,415,281	9,762,218	301,924	9,460,293	1,572,424	$ 21,011,331		$ 21,011,331
14,969,082	467,784	14,501,298	2,566,684	9,762,218	301,924	9,460,293	1,572,424	$ 21,609,127	$ 21,609,127	
14,501,298	467,784	14,033,514	2,352,458	9,460,293	301,924	9,158,369	1,531,876	$ 19,682,473		$ 19,682,473
14,501,298	467,784	14,033,514	2,498,977	9,460,293	301,924	9,158,369	1,531,876	$ 20,284,269	$ 20,284,269	
14,033,514	467,784	13,565,730	2,289,636	9,158,369	301,924	8,856,445	1,491,328	$ 13,037,382		$ 13,037,382
14,033,514	467,784	13,565,730	2,431,271	9,158,369	301,924	8,856,445	1,491,328	$ 13,621,808	$ 13,621,808	
13,565,730	467,784	13,097,946	2,226,813	8,856,445	301,924	8,554,521	1,450,780	$ 11,469,995		$ 11,469,995
13,565,730	467,784	13,097,946	2,363,564	8,856,445	301,924	8,554,521	1,450,780	$ 12,032,776	$ 12,032,776	
13,097,946	467,784	12,630,163	2,163,991	8,554,521	301,924	8,252,596	1,410,232	$ 11,130,798		$ 11,130,798
13,097,946	467,784	12,630,163	2,295,858	8,554,521	301,924	8,252,596	1,410,232	$ 11,671,934	$ 11,671,934	
12,630,163	467,784	12,162,379	2,101,168	8,252,596	301,924	7,950,672	1,369,685	$ 10,791,601		$ 10,791,601
12,630,163	467,784	12,162,379	2,228,151	8,252,596	301,924	7,950,672	1,369,685	$ 11,311,093	$ 11,311,093	
12,162,379	467,784	11,694,595	2,038,346	7,950,672	301,924	7,648,748	1,329,137	$ 10,452,404		$ 10,452,404
12,162,379	467,784	11,694,595	2,160,445	7,950,672	301,924	7,648,748	1,329,137	$ 10,950,251	$ 10,950,251	
11,694,595	467,784	11,226,811	1,975,523	7,648,748	301,924	7,346,824	1,288,589	$ 10,113,207		$ 10,113,207
11,694,595	467,784	11,226,811	2,092,739	7,648,748	301,924	7,346,824	1,288,589	$ 10,589,409	$ 10,589,409	
11,226,811	467,784	10,759,027	1,912,701	7,346,824	301,924	7,044,899	1,248,041	$ 9,774,010		$ 9,774,010
11,226,811	467,784	10,759,027	2,025,032	7,346,824	301,924	7,044,899	1,248,041	$ 10,228,567	$ 10,228,567	
10,759,027	467,784	10,291,244	1,849,878	7,044,899	301,924	6,742,975	1,207,493	$ 9,434,813		$ 9,434,813
10,759,027	467,784	10,291,244	1,957,326	7,044,899	301,924	6,742,975	1,207,493	$ 9,867,726	$ 9,867,726	
10,291,244	467,784	9,823,460	1,787,056	6,742,975	301,924	6,441,051	1,166,945	$ 9,095,616		$ 9,095,616
10,291,244	467,784	9,823,460	1,889,619	6,742,975	301,924	6,441,051	1,166,945	$ 9,506,884	$ 9,506,884	
9,823,460	467,784	9,355,676	1,724,233	6,441,051	301,924	6,139,127	1,126,397	$ 8,756,419		$ 8,756,419
9,823,460	467,784	9,355,676	1,821,913	6,441,051	301,924	6,139,127	1,126,397	$ 9,146,042	$ 9,146,042	
....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....		$ -	
									$ 268,681,752	$ 257,682,252

Delmarva Power & Light Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
112	**Less LTD on Securitization Bonds**	0

Calculation of the above Securitization Adjustments

Attachment 4C - ACE formula Rate Update

Pepco Holdings, Inc

701 Ninth Street, NW
Suite 1100
Washington, DC 20068

Amy L. Blauman
Associate General Counsel

202-872-2122
202-331-6767 Fax
alblauman@pepcoholdings.com

May 15, 2013

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, DC 20426

Re: Atlantic City Electric Company ("Atlantic City")
Informational Filing of 2013 Formula Rate Annual Update in Docket No. ER09-1156 and Pursuant to Approved Settlement Agreement in Docket Nos. ER05-515-000, *et al.*

Dear Ms. Bose,

Atlantic City hereby submits electronically, for informational purposes, its 2013 Annual Formula Rate Update. On April 19, 2006, the Commission approved an uncontested settlement agreement ("Settlement") filed in Docket Nos. ER05-515-000, *et al*., (115 FERC ¶ 61,066). Formula rate implementation protocols contained in the Settlement provide that:

> [o]n or before May 15 of each year, Atlantic [Atlantic City Electric Company] shall recalculate its Annual Transmission Revenue Requirements, producing an "Annual Update" for the upcoming Rate Year, and:
>
> (i) post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page; and
>
> (ii) file such Annual Update with FERC as an informational filing.[1]

The same information contained in this informational filing has been transmitted to PJM for posting on its website as required by the formula rate implementation protocols. Thus, all interested parties should have ample notice of and access to the Annual Update. The protocols provide specific procedures for notice, review, exchanges of information and potential challenges to aspects of the Annual Update. Consequently,

[1] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H1-B, Section 1.b.

and as the Commission has concluded, there is no need for the Commission to notice this informational filing for comment.[2]

Atlantic City's 2013 Annual Update contains no expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices, as defined in 18 C.F.R. § 35.13(b)(7).

Atlantic City has made no Material Accounting Changes as defined in the Settlement.[3] Atlantic City has made no change to Other Post-Employment Benefits ("OPEB") charges that exceed the filing threshold set forth in the Settlement.[4] In addition, Atlantic City has not recorded any extraordinary property losses in FERC Account 182.1. Therefore, no amortization is required over the periods described in the Settlement.[5]

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Very truly yours,

/s/ Amy L. Blauman

Amy L. Blauman
Associate General Counsel
Atlantic City Electric Company

Enclosures

[2] *See* Letter Order Re: Annual Update to Formula Rate in Docket No. ER09-1156 (February 17, 2010).
[3] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H-1B, Section 1.f.(iii).
[4] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H-1B, Section 1.g.
[5] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H-1B, Section 1.h.

ATTACHMENT H-1A

Atlantic City Electric Company

Formula Rate - Appendix A

Shaded cells are input cells

Line	Description		Notes	FERC Form 1 Page # or Instruction	2012
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense			p354.21.b	$ 1,971,778
2	Total Wages Expense			p354.28b	$ 27,001,638
3	Less A&G Wages Expense			p354.27b	$ 951,246
4	Total			(Line 2 - 3)	26,050,392
5	Wages & Salary Allocator			(Line 1 / 4)	7.5691%
	Plant Allocation Factors				
6	Electric Plant in Service		(Note B)	p207.104g	$ 2,614,680,167
7	Common Plant In Service - Electric			(Line 24)	0
8	Total Plant In Service			(Sum Lines 6 & 7)	2,614,680,167
9	Accumulated Depreciation (Total Electric Plant)			p219.29c	$ 748,017,932
10	Accumulated Intangible Amortization		(Note A)	p200.21c	$ 35,034,252
11	Accumulated Common Amortization - Electric		(Note A)	p356	$ -
12	Accumulated Common Plant Depreciation - Electric		(Note A)	p356	$ -
13	Total Accumulated Depreciation			(Sum Lines 9 to 12)	783,052,184
14	Net Plant			(Line 8 - 13)	1,831,627,983
15	Transmission Gross Plant			(Line 29 - Line 28)	754,066,086
16	Gross Plant Allocator			(Line 15 / 8)	28.8397%
17	Transmission Net Plant			(Line 39 - Line 28)	532,388,526
18	Net Plant Allocator			(Line 17 / 14)	29.0664%
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note B)	p207.58.g	$ 739,385,157
20	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year		For Reconc liation Only	Attachment 6 - Enter Negative	
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)			Attachment 6	2,740,600
22	Total Transmission Plant In Service			(Line 19 - 20 + 21)	742,125,757
23	General & Intangible			p205.5.g & p207.99.g	$ 157,751,148
24	Common Plant (Electric Only)		(Notes A & B)	p356	$ -
25	Total General & Common			(Line 23 + 24)	157,751,148
26	Wage & Salary Allocation Factor			(Line 5)	7.56909%
27	General & Common Plant Allocated to Transmission			(Line 25 * 26)	11,940,329
28	Plant Held for Future Use (Including Land)		(Note C)	p214	782,029
29	TOTAL Plant In Service			(Line 22 + 27 + 28)	754,848,115
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note B)	p219.25.c	$ 214,169,813
31	Accumulated General Depreciation			p219.28.c	$ 64,155,290
32	Accumulated Intangible Amortization			(Line 10)	35,034,252
33	Accumulated Common Amortization - Electric			(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)			(Line 12)	0
35	Total Accumulated Depreciation			(Sum Lines 31 to 34)	99,189,542
36	Wage & Salary Allocation Factor			(Line 5)	7.56909%
37	General & Common Allocated to Transmission			(Line 35 * 36)	7,507,747
38	TOTAL Accumulated Depreciation			(Line 30 + 37)	221,677,560
39	TOTAL Net Property, Plant & Equipment			(Line 29 - 38)	533,170,555
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109			Attachment 1	-151,215,322
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative	(Notes A & I)	p266.h	0
42	Net Plant Allocation Factor			(Line 18)	29.07%
43	Accumulated Deferred Income Taxes Allocated To Transmission			(Line 41 * 42) + Line 40	-151,215,322
43a	Transmission Related CWIP (Current Year 12 Month weighted average balances)		(Note B)	p216.43.b as Shown on Attachment 6	0
	Transmission O&M Reserves				
44	Total Balance Transmission Related Account 242 Reserves		Enter Negative	Attachment 5	-2,060,167
	Prepayments				
45	Prepayments		(Note A)	Attachment 5	8,694,772
46	Total Prepayments Allocated to Transmission			(Line 45)	8,694,772
	Materials and Supplies				
47	Undistributed Stores Exp		(Note A)	p227.6c & 16.c	2,285,840
48	Wage & Salary Allocation Factor			(Line 5)	7.57%
49	Total Transmission Allocated			(Line 47 * 48)	173,017
50	Transmission Materials & Supplies			p227.8c	$ 1,963,877
51	Total Materials & Supplies Allocated to Transmission			(Line 49 + 50)	2,136,894
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 85)	16,247,966
53	1/8th Rule			x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission			(Line 52 * 53)	2,030,996
	Network Credits				
55	Outstanding Network Credits		(Note N)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits		(Note N)	From PJM	0
57	Net Outstanding Credits			(Line 55 - 56)	0
58	TOTAL Adjustment to Rate Base			(Line 43 + 43a + 44 + 46 + 51 + 54 - 57)	-140,412,826
59	Rate Base			(Line 39 + 58)	392,757,728

O&M

	Transmission O&M				
60	Transmission O&M		p321.112.b	$	11,489,433
61	Less extraordinary property loss		Attachment 5		0
62	Plus amortized extraordinary property loss		Attachment 5		0
63	Less Account 565		p321.96.b	$	-
64	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note O)	PJM Data	$	-
65	Plus Transmission Lease Payments	(Note A)	p200.3c	$	-
66	Transmission O&M		(Lines 60 - 63 + 64 + 65)		11,489,433
	Allocated General & Common Expenses				
67	Common Plant O&M	(Note A)	p356	$	-
68	Total A&G		p323.197.b	$	66,638,194
69	Less Property Insurance Account 924		p323.185b	$	401,319
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$	4,681,646
71	Less General Advertising Exp Account 930.1		p323.191b	$	228,403
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b	$	-
73	Less EPRI Dues	(Note D)	p352-353	$	-
74	General & Common Expenses		(Lines 67 + 68) - Sum (69 to 73)		61,326,826
75	Wage & Salary Allocation Factor		(Line 5)		7.5691%
76	General & Common Expenses Allocated to Transmission		(Line 74 * 75)		4,641,884
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b		0
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		0
80	Property Insurance Account 924		p323.185b	$	401,319
81	General Advertising Exp Account 930.1	(Note F)	p323.191b		0
82	Total		(Line 80 + 81)		401,319
83	Net Plant Allocation Factor		(Line 18)		29.07%
84	A&G Directly Assigned to Transmission		(Line 82 * 83)		116,649
85	Total Transmission O&M		(Line 66 + 76 + 79 + 84)		16,247,966

Depreciation & Amortization Expense

	Depreciation Expense			
86	Transmission Depreciation Expense		p336.7b&c	17,350,440
87	General Depreciation		p336.10b&c	6,419,695
88	Intangible Amortization	(Note A)	p336.1d&e	51,891
89	Total		(Line 87 + 88)	6,471,586
90	Wage & Salary Allocation Factor		(Line 5)	7.5691%
91	General Depreciation Allocated to Transmission		(Line 89 * 90)	489,840
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0
94	Total		(Line 92 + 93)	0
95	Wage & Salary Allocation Factor		(Line 5)	7.5691%
96	Common Depreciation - Electric Only Allocated to Transmission		(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization		(Line 86 + 91 + 96)	17,840,280

Taxes Other than Income

98	Taxes Other than Income	Attachment 2	799,510
99	Total Taxes Other than Income	(Line 98)	799,510

Return / Capitalization Calculations

	Long Term Interest					
100	Long Term Interest			p117.62c through 67c		70,393,088
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		16,687,316
102	Long Term Interest			"(Line 100 - line 101)"		53,705,772
103	Preferred Dividends		enter positive	p118.29c	$	-
	Common Stock					
104	Proprietary Capital			p112.16c	$	803,970,384
105	Less Preferred Stock		enter negative	(Line 114)		0
106	Less Account 216.1		enter negative	p112.12c	$	-
107	Common Stock			(Sum Lines 104 to 106)		803,970,384
	Capitalization					
108	Long Term Debt			p112.17c through 21c	$	1,084,052,035
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$	(9,670,149)
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$	-
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1		-2,323,607
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8		-231,760,646
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)		840,297,633
114	Preferred Stock			p112.3c	$	-
115	Common Stock			(Line 107)		803,970,384
116	Total Capitalization			(Sum Lines 113 to 115)		1,644,268,017
117	Debt %	Total Long Term Debt	(Note Q)	(Line 113 / 116)		50%
118	Preferred %	Preferred Stock	(Note Q)	(Line 114 / 116)		0%
119	Common %	Common Stock	(Note Q)	(Line 115 / 116)		50%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)		0.0639
121	Preferred Cost	Preferred Stock		(Line 103 / 114)		0.0000
122	Common Cost	Common Stock	(Note J)	Fixed		0.1130
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)		0.0320
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)		0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)		0.0565
126	Total Return (R)			(Sum Lines 123 to 125)		0.0885
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)		34,741,934

	Composite Income Taxes				
	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite		(Note I)		8.99%
130	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
132	T/ (1-T)				69.05%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	p266.8f	$ (926,105)
134	T/(1-T)			(Line 132)	69.05%
135	Net Plant Allocation Factor			(Line 18)	29.0664%
136	ITC Adjustment Allocated to Transmission			(Line 133 * (1 + 134) * 135)	-455,062
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	15,323,086
138	Total Income Taxes			(Line 136 + 137)	14,868,024
	REVENUE REQUIREMENT				
	Summary				
139	Net Property, Plant & Equipment			(Line 39)	533,170,555
140	Adjustment to Rate Base			(Line 58)	-140,412,826
141	Rate Base			(Line 59)	392,757,728
142	O&M			(Line 85)	16,247,966
143	Depreciation & Amortization			(Line 97)	17,840,280
144	Taxes Other than Income			(Line 99)	799,510
145	Investment Return			(Line 127)	34,741,934
146	Income Taxes			(Line 138)	14,868,024
147	Gross Revenue Requirement			(Sum Lines 142 to 146)	84,497,714
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
148	Transmission Plant In Service			(Line 19)	739,385,157
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0
150	Included Transmission Facilities			(Line 148 - 149)	739,385,157
151	Inclusion Ratio			(Line 150 / 148)	100.00%
152	Gross Revenue Requirement			(Line 147)	84,497,714
153	Adjusted Gross Revenue Requirement			(Line 151 * 152)	84,497,714
	Revenue Credits & Interest on Network Credits				
154	Revenue Credits			Attachment 3	3,135,535
155	Interest on Network Credits		(Note N)	PJM Data	-
156	Net Revenue Requirement			(Line 153 - 154 + 155)	81,362,178
	Net Plant Carrying Charge				
157	Net Revenue Requirement			(Line 156)	81,362,178
158	Net Transmission Plant			(Line 19 - 30)	525,215,344
159	Net Plant Carrying Charge			(Line 157 / 158)	15.4912%
160	Net Plant Carrying Charge without Depreciation			(Line 157 - 86) / 158	12.1877%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 157 - 86 - 127 - 138) / 158	2.7421%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
162	Net Revenue Requirement Less Return and Taxes			(Line 156 - 145 - 146)	31,752,220
163	Increased Return and Taxes			Attachment 4	52,929,772
164	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 162 + 163)	84,681,992
165	Net Transmission Plant			(Line 19 - 30)	525,215,344
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 164 / 165)	16.1233%
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation			(Line 163 - 86) / 165	12.8198%
168	Net Revenue Requirement			(Line 156)	81,362,178
169	True-up amount			Attachment 6	(1,686,559)
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects			Attachment 7	454,756
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)			Attachment 5	-
172	Net Zonal Revenue Requirement			(Line 168 - 169 + 171)	80,130,375
	Network Zonal Service Rate				
173	1 CP Peak		(Note L)	PJM Data	2,809
174	Rate ($/MW-Year)			(Line 172 / 173)	28,526
175	Network Service Rate ($/MW/Year)			(Line 174)	28,526

Notes

A Electric portion only

B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in the PJM Regional Transmission Plan (RTEP) must be separately detailed on Attachment 5. For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

C Transmission Portion Only

D All EPRI Annual Membership Dues

E All Regulatory Commission Expenses

F Safety related advertising included in Account 930.1

G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

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. ER08-10, the ROE is 11.30%, which includes a 50 basis-point RTO membership adder as authorized by FERC to become effective on December 1, 2007. Per FERC orders in Docket Nos. ER08-686 and ER08-1423, the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point transmission incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November 1, 2008 respectively.

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 and the PJM established billing determinants will not be revised or updated in the annual rate reconciliations per settlement in ER05-515.

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) 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 Transmisison Owner whole on Line 155.

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 in on line 64

P Securitization bonds may be included in the capital structure per settlement in ER05-515.

Q ACE capital structure is initially fixed at 50% common equity and 50% debt per settlement in ER05-515 subject to moratorium provisions in the settlement.

R Per the settlement in ER05-515, the facility credits of $15,000 per month paid to Vineland will increase to $37,500 per month (prorated for partial months) effective on the date FERC approves the settlement in ER05-515.

END

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	(201,584,816)	0	
ADIT-283	(198,801)	(377,608,352)	(51,070,363)	
ADIT-190	674,184	65,187,247	5,451,864	
Subtotal	475,383	(514,005,921)	(45,618,499)	
Wages & Salary Allocator			7.5691%	
Gross Plant Allocator		28.8397%		
ADIT	475,383	(148,237,799)	(3,452,906)	(151,215,322)

Note: ADIT associated with Gain or Loss on Reacquired Debt is ncluded in Column A here and included in Cost of Debt on Appendix A, Line 111.
Amount 2,323,607

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.

ADIT-190	A	B Total	C Gas, Prod or Other Related	D Only Transmission Related	E Plant	F Labor	G Justifications
190	BAD DEBT RESERVE	4,693,831	4,693,831				Under the Tax Reform Act of 1986, taxpayers were required to account for bad debts using the specific write-off method. The reserve method is used for book purposes. The amount represents the add-back of book reserve. Reta l related.
190	ACCRUAL SEVERANCE	1,573,180				1,573,180	For book purposes, the costs are expensed when a formal plan is adopted and the employees to be severed have been identified. For tax purposes, the costs are deductible when they are paid to the severed individual.
190	ENVIRONMENTAL EXPENSE	733,609	733,609				These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for environmental site clean-up expenses. For tax no deduction is permitted until the "all events" test is met typically when economic performance has occurred. This book reserve is primarily related to Deepwater and BL England sites wh ch should not be in transmission service. Generation Related.
190	MARK TO MARKET § 475 ADJUSTMENT	36,039			36,039		Pursuant to IRC Sec 475, the company is tak ng deduction to mark-to-market its accounts receivable. For book purposes, the receivables remained valued at their original amounts. Reflects unbilled revenues and customer accounts receivables. Applies to all functions.
190	OPEB	14,308,459				14,308,459	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
190	SECTION 461(H) - PREPAID INSURANCE	4,093,691			4,093,691		Book records a deduction for accrual liabilities of worker compensation and T&D property insurance. A tax deduction is only allowed for actual payments made. Related to both T & D plant
190	SERP	282,580				282,580	Affects company personnel across all functions.
190	NOL	55,006,294			55,006,294		Related to both T & D plant
190	Stranded Costs	(2,716,779)	(2,716,779)				All Generation related
190	Accrued Liab - Auto	138,750				138,750	Affects copany personnel across all functions
190	Accrued Liab - Misc.	1,921,568			1,921,568		Related to T&D plant
190	Deferred Comp	347,734				347,734	For book purposes, deferred compensation and deferred payments are expensed when accrued. For tax purposes, they are not deducted until paid. Affects company personnel across all functions.
190	Accrued Liability - General	2,274,784			2,274,784		Related to T&D plant
190	Accrued Liability - Health Claim	278,571				278,571	Affects copany personnel across all functions
190	Accrued Vacation	2,277,029				2,277,029	Affects copany personnel across all functions
190	Charitable Contribution Limit	772,575	772,575				Related to gas, production or other
190	Income from Partnerships/Trusts	(151,998)	(151,998)				Related to gas, production or other
190	Accumulated Deferred Investment Tax Credit	1,979,863			1,979,863		Related to T&D plant
190	Reg Asset - FERC Formula Rate Adj. Trans. Svc	674,184		674,184			Related to gas, production or other
190	1999 AMT	1,625,338			1,625,338		Plant related
190	Accrued Liability - Directors' Fees	(45,057)			(45,057)		Related to T&D plant
190	Regulatory Liability - Demand Response Working Group	(14)				(14)	Affects company personnel across all functions.
190	BGS Deferred Related - Retail	25,419,346	25,419,346				Reta l related
190	Plant Related	(44,755)	-		(44,755)		Related to T&D plant
190	Accrued Sick Pay	554,034				554,034	Affects copany personnel across all functions
190	Use Tax Reserve	319,345			319,345		Related to T&D plant
190	Subtotal - p234	116,352,201	28,750,584	674,184	67,167,110	19,760,323	
190	Less FASB 109 Above if not separately removed	1,979,863			1,979,863		
190	Less FASB 106 Above if not separately removed	14,308,459				14,308,459	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
190	Total	100,063,879	28,750,584	674,184	65,187,247	5,451,864	

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.
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Atlantic City Electric Company

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	Labor	Justifications
282	Deregulation/Stranded Cost Generation Assets	(108,418,163)	(108,418,163)	-	-	-	This deferred tax balance relates to our plant and results from life and method differences. Generation related
282	Plant Related	(379,785,237)	(68,293,308)		(311,491,929)	-	This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
282	Plant Related (Reclass)	56,625			56,625	-	This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
282	Subtotal - p275	(488,146,775)	(176,711,471)	-	(311,435,304)	-	
282	Less FASB 109 Above if not separately removed	(109,850,488)			(109,850,488)		
282	Less FASB 106 Above if not separately removed						
282	Total	(378,296,287)	(176,711,471)	-	(201,584,816)	-	

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.
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

	A	B	C	D	E	F	G
ADIT-283		Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
283	LOSS ON REACQ DEBT	2,323,607	2,323,607				The cost of bond redemption is deductible currently for tax purposes and is amortized over the l fe of the new bond issue for book purposes. Excluded here since included in Cost of Debt
283	ASBESTOS REMOVAL	(2)	(2)				as paid . These costs were deferred and amortized for book purposes. Generat on
283	Misc Deferred Debits - Retail	(52,279)	(52,279)				Reta l related
283	DEFERRED EXPENSE CLEARING	(1,208,408)			(1,208,408)		Reflects the deferred taxes generated as a result of the tax deductions taken for actual store room expenses. For book purposes, these amounts were recorded as an asset in FERC account 163.
283	DSM COSTS	(817,333)	(817,333)				For books, Demand Side Management Costs are deferred. For tax these costs are expensed when paid. These deferred taxes are the result of this book/tax difference which is retail in nature. Retail related.
283	Gross up on FAS 109 Deferred Taxes	(15,014,331)			(15,014,331)		FAS 109 Plant related
283	Stranded Costs	290,418,228	290,418,228				All Generation related
283	PENSION PAYMENT RESERVE	(48,082,064)				(48,082,064)	Affects company personnel across all functions.
283	NUG BUYOUT	(18,144,239)	(18,144,239)				Generation related
283	AMORT of OPEB	(2)				(2)	OPEB, labor related and relates to all functions
283	Regulatory Asset - General	436,048				436,048	Regulatory liability for universal service fund
283	Regulatory Asset - SREC Program	(1,559,734)	(1,559,734)				Generation related - Solar Renewable EnergyCertificate Program
283	Regulatory Asset - NJ RGGI	(768,300)	(768,300)			-	Related to gas, production or other
283	Reg Asset - FERC Formula Rate Adj. Trans. Svc	(198,801)		(198,801)			Related to gas, production or other
283	BGS Deferred Related - Retail	(66,726,477)	(66,726,477)				Reta l related
283	Accrued Vacation	(3,424,345)				(3,424,345)	Affects company personnel across all functions.
283	Decommissioning & Decontaminat on	(21,210)	(21,210)				Related to gas, production or other
283	Reg Asset - NJ L/T Capacity Agreement	(22,362)	(22,362)				Costs related to NJ Long-term Capacity Pilot Program to promote the construction of qualified electric generation facilities for the benefit of NJ's electric consumers. Related to gas, production or other.
283	Reg Asset-NJ Rec-Base	(16,934,127)			(16,934,127)		Related to both T & D plant
283	Plant Related	(359,465,817)	-		(359,465,817)		Related to T&D plant
283	Income from Partnerships/Trusts	(55,170)	(55,170)				Related to gas, production or other
283	Subtotal - p277 (Form 1-F filer: see note 6, below)	(239,317,118)	204,574,729	(198,801)	(392,622,683)	(51,070,363)	
283	Less FASB 109 Above if not separately removed	(15,014,331)			(15,014,331)		
283	Less FASB 106 Above if not separately removed						
283	Total	(224,302,787)	204,574,729	(198,801)	(377,608,352)	(51,070,363)	

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 C1. 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.
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

		Item		Balance	Amortization
1	Rate Base Treatment				
2	Balance to line 41 of Appendix A	Total			
3	Amortization				
4	Amortization to line 133 of Appendix A	Total		6,155,421	926,105
5	Total			6,155,421	926,105
6	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.:		6,155,421	926,105
7	Difference /1			-	-

/1 Difference must be zero

Atlantic City Electric Company

Attachment 2 - Taxes Other Than Income Worksheet

Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
Plant Related		***Gross Plant Allocator***	
1 Real property (State, Municipal or Local)	2,313,580		
2 Personal property	-		
3 City License	-		
4 State Excise	-		
Total Plant Related	2,313,580	28.8397%	667,230
Labor Related		***Wages & Salary Allocator***	
5 Federal FICA & Unemployment	1,532,881		
6 Unemployment	140,540		
Total Labor Related	1,673,421	7.5691%	126,663
Other Included		***Gross Plant Allocator***	
7 Miscellaneous	19,478		
Total Other Included	19,478	28.8397%	5,617
Total Included			799,510
Excluded			
8 State Franchise tax	-		
9 TEFA	14,826,464		
10 Use & Sales Tax	1,001,261		
11 Total "Other" Taxes (included on p. 263)	19,834,204		
12 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	19,834,204		
13 Difference	-		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be 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

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Atlantic City Electric Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		849,942
2	Total Rent Revenues	(Sum Line 1)	849,942
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 880,024
4	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) (Note 4)		-
5	Point to Point Service revenues for which the load is not included in he divisor received by Transmission Owner (Note 4)		1,384,746
6	PJM Transitional Revenue Neutrality (Note 1)		-
7	PJM Transitional Market Expansion (Note 1)		-
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		619,380
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	3,734,092
12	Less line 17g		(598,556)
13	Total Revenue Credits		3,135,535

<u>Revenue Adjustment to determine Revenue Credit</u>

14 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 173 of Appendix A.

15 Note 2: If the costs associated with he 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.

16 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). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, 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).

17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	849,942
17b	Costs associated with revenues in line 17a	347,171
17c	Net Revenues (17a - 17b)	502,771
17d	50% Share of Net Revenues (17c / 2)	251,385
17e	Costs associated with revenues in line 17a hat 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.	-
17f	Net Revenue Credit (17d + 17e)	251,385
17g	Line 17f less line 17a	(598,556)
18	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 is 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.	13,264,575
19	Amount offset in line 4 above	78,791,668
20	Total Account 454, 456 and 456.1	95,790,335
21	Note 4: SECA revenues booked in Account 447.	

Atlantic City Electric Company

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 127 + Line 138)	52,929,772
B	100 Basis Point increase in ROE				1.00%
	Return Calculation				
59	Rate Base			(Line 39 + 58)	392,757,728
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	70,393,088
101	Less LTD Interest on Securitization B	(Note P)		Attachment 8	16,687,316
102	**Long Term Interest**			"(Line 100 - line 101)"	53,705,772
103	**Preferred Dividends**		enter positive	p118.29c	0
	Common Stock				
104	Proprietary Capital			p112.16c	803,970,384
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	0
107	**Common Stock**			(Sum Lines 104 to 106)	803,970,384
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,084,052,035
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	-9,670,149
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss		enter nega ive	Attachment 1	-2,323,607
112	Less LTD on Securitization Bonds		enter nega ive	Attachment 8	-231,760,646
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	840,297,633
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	803,970,384
116	**Total Capitalization**			(Sum Lines 113 to 115)	1,644,268,017
117	Debt %	(Note Q from Appendix A)	Total Long Term Debt	(Line 113 / 116)	50%
118	Preferred %	(Note Q from Appendix A)	Preferred Stock	(Line 114 / 116)	0%
119	Common %	(Note Q from Appendix A)	Common Stock	(Line 115 / 116)	50%
120	Debt Cost		Total Long Term Debt	(Line 102 / 113)	0.0639
121	Preferred Cost		Preferred Stock	(Line 103 / 114)	0.0000
122	Common Cost	(Note J from Appendix A)	Common Stock	Appendix A % plus 100 Basis Pts	0.1230
123	Weighted Cost of Debt		Total Long Term Debt (WCLTD)	(Line 117 * 120)	0.0320
124	Weighted Cost of Preferred		Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common		Common Stock	(Line 119 * 122)	0.0615
126	Total Return (R)			**(Sum Lines 123 to 125)**	**0.0935**
127	Investment Return = Rate Base * Rate of Return			**(Line 59 * 126)**	**36,705,723**
	Composite Income Taxes			(Note L)	
	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite				8.99%
130	p = percent of federal income tax deductible for state purposes			Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
132	T/ (1-T)				69.05%
	ITC Adjustment				
133	Amortized Investment Tax Credit		enter negative	p266 8f	-926,105
134	T/(1-T)			(Line 132)	69.05%
135	Net Plant Allocation Factor			(Line 18)	29.0664%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-455,062**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			16,679,111
138	**Total Income Taxes**				**16,224,049**

Atlantic City Electric Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 35,034,252	35,034,252	0	Respondent is Electric Utility only.
11	Accumulated Common Amortization - Electric	(Note A)	p356	0	0	0	
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	0	0	0	
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	6,155,421	6,155,421	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	2,285,840	2,285,840	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses						
65	Plus Transmission Lease Payments	(Note A)	p200.3c	0			
67	Common Plant O&M	(Note A)	p356	0	0	0	
	Depreciation Expense						
88	Intangible Amortization	(Note A)	p336.1d&e	51,891	51,891	0	Respondent is Electric Utility only.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0	0	0	
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0	0	0	

Transmission / Non-transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	7,375,795	782,029	6,593,766	Transmission Right of Way - Car l's Corner to Landis
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.160b	4,681,646	0	4,681,646	

CWIP & Expensed Lease Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	2,614,680,167	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	739,385,157	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	214,169,813	0	0	See Form 1

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	0	0	See Form 1

Atlantic City Electric Company

Attachment 5 - Cost Support

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
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	4,681,646	0	4,681,646	Transmission related.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	4,681,646	0	4,681,646	Transmission related.

Safety Related Advertising Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	228,403	-	228,403	None

MultiState Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				NJ	PA				Enter Calculation
129	SIT=State Income Tax Rate or Composite	(Note I)	8.9945%	9.00%	9.990%				Apportioned: NJ 8.8866%, PA 0.1079%

Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	228,403	-	228,403	None

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					
149	Excluded Transmission Facilities		(Note M)	Attachment 5	-	General Description of the Facilities
	Instructions:				Enter $	None
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			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

Atlantic City Electric Company

Attachment 5 - Cost Support

Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Outstanding Network Credits	Description of the Credits
	Network Credits			Enter $	
55	Outstanding Network Credits	(Note N)	From PJM	0	General Description of the Credits
					None
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0	
					None
					Add more lines if necessary

Transmission Related Account 242 Reserves

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Total	Allocation	Transmission Related	Details
44	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)	Enter $		Amount	
	Directly Assignable to Transmission	-	100%	-	
	Labor Related, General plant related or Common Plant related	9,293,604	7.57%	703,441	
	Plant Related	4,704,366	28.84%	1,356,725	
	Other		0.00%	-	
	Total Transmission Related Reserves	13,997,969		2,060,167	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45	Prepayments					
5	Wages & Salary Allocator			7.569%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	7.569%	-	
	Prepayments	$	27,157,992	7.569%	2,055,613	
	Prepaid Pensions if not included in Prepayments	$	87,714,082	7.569%	6,639,159	
			114,872,074		8,694,772	
						Add more lines if necessary

Extraordinary Property Loss

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Amount	Number of years	Amortization	w/ interest
61	Less extraordinary property loss	Attachment 5	$ -			
62	Plus amortized extraordinary property loss	Attachment 5		5	$ -	$ -

Atlantic City Electric Company

Attachment 5 - Cost Support

Interest on Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Interest on Network Credits	Description of the Interest on the Credits
	Revenue Credits & Interest on Network Credits				
155	Interest on Network Credits	(Note N)	PJM Data	0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & PJM Documentation
	Net Revenue Requirement		
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)	-	Settelement agreement.

PJM Load Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
173	1 CP Peak	(Note L)	PJM Data	2,809.0	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
ACE zone						
Total						

Atlantic City Electric Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	$ 10,319,368	$ 8,778,179	$ 19,411,471	$ 4,732,311	$ 43,241,329
Procurement & Administrative Services	6,800,125	5,117,604	11,142,880	1,168,548	24,229,157
Financial Services & Corporate Expenses	13,119,301	10,095,632	19,784,530	2,113,560	45,113,024
Insurance Coverage and Services	2,722,299	2,318,184	3,992,693	1,182,610	10,215,785
Human Resources	4,842,098	3,325,597	7,918,949	1,098,248	17,184,892
Legal Services	3,696,208	2,776,662	6,956,240	521,371	13,950,480
Audit Services	889,689	686,619	1,654,755	194,081	3,425,144
Customer Services	50,035,762	39,174,928	27,817,940	9,258	117,037,888
Utility Marketing Services	366,622	328,711	630,571	-	1,325,904
Information Technology	16,578,099	12,158,126	38,724,477	419,276	67,879,979
External Affairs	2,615,303	2,177,747	5,210,186	465,886	10,469,122
Environmental Services	1,360,579	1,119,104	1,973,001	148,481	4,601,165
Safety Services	388,220	368,439	633,768	-	1,390,427
Regulated Electric & Gas Delivery	27,135,040	20,392,061	40,410,791	1,086	87,938,979
Energy Business	-	-	-	3,902	3,902
Internal Consulting Services	236,486	183,469	712,652	-	1,132,607
Interns	80,850	40,490	165,202	-	286,541
Cost of Benefits	11,931,169	7,425,942	18,880,059	3,008,206	41,245,375
Building Services	8,336	94,433	4,845,257	-	4,948,027
Total	$153,125,554	$116,561,926	$210,865,421	$ 15,066,825	$495,619,726

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2012

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Potomac Electric Power Company	66,537,297	144,074,045	254,079	210,865,421
2	Delmarva Power & Light Company	39,129,111	113,813,964	182,479	153,125,554
3	Atlantic City Electric Company	24,278,507	92,144,935	138,484	116,561,926
4	Pepco Energy Services, Inc.	3,241,220	8,643,664	15,330	11,900,214
5	Conectiv, LLC	51,957	790,021	2,094	844,072
6	Potomac Capital Investment Corporation	247,670	319,705	904	568,279
7	Thermal Energy Limited Partnership	19,186	526,060	716	545,962
8	ATS Operating Services, Inc.	141	273,158	312	273,611
9	Atlantic Southern Properties, Inc.	18,351	243,366	390	262,107
10	Conectiv Energy Supply, Inc.	39,953	147,691	1,059	188,703
11	Pepco Holdings, Inc.	112,705	64,916	499	178,120
12	Conectiv Properties and Investment, Inc.	36,456	132,037	221	168,714
13	Conectiv Thermal Systems, Inc.	5,562	93,841	115	99,518
14	Conectiv Communications, Inc.	95	11,553	20	11,668
15	Atlantic City Electric Transition Funding, LLC	4,111	2,728	4	6,843
16	Conectiv North East, LLC	256	4,953	8	5,217
17	Delaware Operating Services Company	235	4,943	4	5,182
18	ATE Investment, Inc.	2,954	1,042	8	4,004
19	Atlantic Generation, Inc.	180	2,567	4	2,751
20	Conectiv Services II, Inc.	41	1,473	13	1,527
21	Conectiv Solutions LLC	313	18	1	332
22	Atlantic Jersey Thermal Systems, Inc.		1		1
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	**133,726,301**	**361,290,681**	**596,744**	**495,610,726**

Atlantic City Electric Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)

78,895,080 Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar					9.5	-	-	-	-	-	-	-	-	
Apr	160,962				8.5	1,368,177	-	-	-	114,015	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	17,687,389				6.5	114,968,029	-	-	-	9,580,669	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	17,848,351	-	-	-		116,336,206	-	-	-	9,694,684	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										9,694,684	-	-	-	
Input to Line 21 of Appendix A										9,694,684	-		-	9,694,684
Input to Line 43a of Appendix A												-		-
Month In Service or Month for CWIP										5.48	#DIV/0!	#DIV/0!	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 9,694,684 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

79,890,657 — Must run Appendix A to get this number (with inputs on lines 21 and 43a of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)

$ 79,890,657

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

81,564,812 Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2
For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 55,263,256 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan	6,802,596				11.5	78,229,856	-	-	-	6,519,155	-	-	-	
Feb	4,040,314				10.5	42,423,296	-	-	-	3,535,275	-	-	-	
Mar	5,429,950				9.5	51,584,526	-	-	-	4,298,710	-	-	-	
Apr	2,429,759				8.5	20,652,953	-	-	-	1,721,079	-	-	-	
May	17,358,785				7.5	130,190,889	-	-	-	10,849,241	-	-	-	
Jun	3,070,118				6.5	19,955,766	-	-	-	1,662,981	-	-	-	
Jul	2,434,165				5.5	13,387,909	-	-	-	1,115,659	-	-	-	
Aug	76,679				4.5	345,055	-	-	-	28,755	-	-	-	
Sep	214,689				3.5	751,412	-	-	-	62,618	-	-	-	
Oct	536,275				2.5	1,340,687	-	-	-	111,724	-	-	-	
Nov	915,504				1.5	1,373,256	-	-	-	114,438	-	-	-	
Dec	11,954,422				0.5	5,977,211	-	-	-	498,101	-	-	-	
Total	55,263,256	-	-	-		366,212,815	-	-	-	30,517,735	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										30,517,735	-	-	-	
								Input to Line 21 of Appendix A		30,517,735	-		-	30,517,735
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.37	#DIV/0!	#DIV/0!	#DIV/0!	

79,029,818 Result of Formula for Reconciliation Must run Appendix A with cap adds in line 21 & line 20
(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar					9.5	-	-	-	-	-	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	4,520,489				6.5	29,383,176	-	-	-	2,448,598	-	-	-	
Jul	637,095				5.5	3,504,024	-	-	-	292,002	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	5,157,584	-	-	-		32,887,200	-	-	-	2,740,600	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										2,740,600	-	-	-	
81,816,934								Input to Line 21 of Appendix A		2,740,600	-		-	2,740,600
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.62	#DIV/0!	#DIV/0!	#DIV/0!	

9 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconci iation in Step 7		The forecast in Prior Year		
79,029,818	-	80,658,713	=	(1,628,895)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March c 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(135,741)	0.2800%	11.5	(4,371)	(140,112)
Jul	Year 1	(135,741)	0.2800%	10.5	(3,991)	(139,732)
Aug	Year 1	(135,741)	0.2800%	9.5	(3,611)	(139,352)
Sep	Year 1	(135,741)	0.2800%	8.5	(3,231)	(138,972)
Oct	Year 1	(135,741)	0.2800%	7.5	(2,851)	(138,592)
Nov	Year 1	(135,741)	0.2800%	6.5	(2,470)	(138,212)
Dec	Year 1	(135,741)	0.2800%	5.5	(2,090)	(137,832)
Jan	Year 2	(135,741)	0.2800%	4.5	(1,710)	(137,452)
Feb	Year 2	(135,741)	0.2800%	3.5	(1,330)	(137,072)
Mar	Year 2	(135,741)	0.2800%	2.5	(950)	(136,691)
Apr	Year 2	(135,741)	0.2800%	1.5	(570)	(136,311)
May	Year 2	(135,741)	0.2800%	0.5	(190)	(135,931)
Total		(1,628,895)				(1,656,260)

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(1,656,260)	0.2800%	(140,547)	(1,520,351)
Jul	Year 2	(1,520,351)	0.2800%	(140,547)	(1,384,062)
Aug	Year 2	(1,384,062)	0.2800%	(140,547)	(1,247,391)
Sep	Year 2	(1,247,391)	0.2800%	(140,547)	(1,110,337)
Oct	Year 2	(1,110,337)	0.2800%	(140,547)	(972,899)
Nov	Year 2	(972,899)	0.2800%	(140,547)	(835,077)
Dec	Year 2	(835,077)	0.2800%	(140,547)	(696,868)
Jan	Year 3	(696,868)	0.2800%	(140,547)	(558,273)
Feb	Year 3	(558,273)	0.2800%	(140,547)	(419,290)
Mar	Year 3	(419,290)	0.2800%	(140,547)	(279,917)
Apr	Year 3	(279,917)	0.2800%	(140,547)	(140,154)
May	Year 3	(140,154)	0.2800%	(140,547)	-
Total with interest				(1,686,559)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		(1,686,559)
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$	81,816,934
Revenue Requirement for Year 3		80,130,375

10 May Year 3 Post results of Step 9 on PJM web site

$ 80,130,375 Post results of Step 3 on PJM web site

11 June Year 3 Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 80,130,375

Atlantic City Electric Company

Attachment 7 - Transmission Enhancement Charge Worksheet

Line					
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if not a CIAC**				
3			Formula Line		
4		A	160	Net Plant Carrying Charge without Depreciation	12.1877%
5		B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	12.8198%
6		C		Line B less Line A	0.6321%
7	**FCR if a CIAC**				
8		D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.7421%

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

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

Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis point RTO membership adder as authorized by FERC

11 **incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November 1, 2008 respectively.**

Line		Details		B0265 Mickelton		B0276 Monroe
12	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes		Yes
13	Useful life of project	Life		35		35
14	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 18, Otherwise "No"	CIAC	(Yes or No)	No		No
15	Input the allowed ROE Incentive	Increased ROE (Basis Points)		150		0
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		12.1877%		12.1877%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		13.1358%		12.1877%
18	Columns A, B or C from Attachment 6	Investment		4,854,660	may be weighted average of small projects	7,878,071
19	Line 18 divided by line 13	Annual Depreciation Exp		138,705		225,088
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		6.00		6.00

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
31	Base FCR	2013	4,369,194	138,705	4,230,489	654,304	7,090,264	225,088	6,865,176	1,061,796
32	W Increased ROE	2013	4,369,194	138,705	4,230,489	694,415	7,090,264	225,088	6,865,176	1,061,796
33	Base FCR	2014	4,230,489	138,705	4,091,785	637,400	6,865,176	225,088	6,640,088	1,034,363
34	W Increased ROE	2014	4,230,489	138,705	4,091,785	676,195	6,865,176	225,088	6,640,088	1,034,363
35	Base FCR	2015	4,091,785	138,705	3,953,080	620,495	6,640,088	225,088	6,415,001	1,006,930
36	W Increased ROE	2015	4,091,785	138,705	3,953,080	657,975	6,640,088	225,088	6,415,001	1,006,930
37	Base FCR	2016	3,953,080	138,705	3,814,376	603,590	6,415,001	225,088	6,189,913	979,497
38	W Increased ROE	2016	3,953,080	138,705	3,814,376	639,755	6,415,001	225,088	6,189,913	979,497
39	Base FCR	2017	3,814,376	138,705	3,675,671	586,685	6,189,913	225,088	5,964,825	952,064
40	W Increased ROE	2017	3,814,376	138,705	3,675,671	621,535	6,189,913	225,088	5,964,825	952,064
41	Base FCR	2018	3,675,671	138,705	3,536,967	569,780	5,964,825	225,088	5,739,737	924,630
42	W Increased ROE	2018	3,675,671	138,705	3,536,967	603,315	5,964,825	225,088	5,739,737	924,630
43	Base FCR	2019	3,536,967	138,705	3,398,262	552,875	5,739,737	225,088	5,514,650	897,197
44	W Increased ROE	2019	3,536,967	138,705	3,398,262	585,095	5,739,737	225,088	5,514,650	897,197
45	Base FCR	2020	3,398,262	138,705	3,259,557	535,970	5,514,650	225,088	5,289,562	869,764
46	W Increased ROE	2020	3,398,262	138,705	3,259,557	566,875	5,514,650	225,088	5,289,562	869,764
47	Base FCR	2021	3,259,557	138,705	3,120,853	519,065	5,289,562	225,088	5,064,474	842,331
48	W Increased ROE	2021	3,259,557	138,705	3,120,853	548,655	5,289,562	225,088	5,064,474	842,331
49	Base FCR	2022	3,120,853	138,705	2,982,148	502,160	5,064,474	225,088	4,839,386	814,898
50	W Increased ROE	2022	3,120,853	138,705	2,982,148	530,435	5,064,474	225,088	4,839,386	814,898
51	Base FCR	2023	2,982,148	138,705	2,843,444	485,255	4,839,386	225,088	4,614,299	787,465
52	W Increased ROE	2023	2,982,148	138,705	2,843,444	512,215	4,839,386	225,088	4,614,299	787,465
53	Base FCR	2024	2,843,444	138,705	2,704,739	468,350	4,614,299	225,088	4,389,211	760,032
54	W Increased ROE	2024	2,843,444	138,705	2,704,739	493,995	4,614,299	225,088	4,389,211	760,032
55	Base FCR	2025	2,704,739	138,705	2,566,035	451,445	4,389,211	225,088	4,164,123	732,599
56	W Increased ROE	2025	2,704,739	138,705	2,566,035	475,775	4,389,211	225,088	4,164,123	732,599
57	Base FCR	2026	2,566,035	138,705	2,427,330	434,541	4,164,123	225,088	3,939,035	705,166
58	W Increased ROE	2026	2,566,035	138,705	2,427,330	457,555	4,164,123	225,088	3,939,035	705,166
59	Base FCR	2027	2,427,330	138,705	2,288,625	417,636	3,939,035	225,088	3,713,948	677,733
60	W Increased ROE	2027		138,705	(138,705)	120,485	3,939,035	225,088	3,713,948	677,733
61		....		....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....
63										

to become effecitve on December 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE for specific projects identified or to be indentified in Attachr

B0211 Union-Corson				B0210 Orchard-500kV				B0210 Orchard-Below 500kV			
Yes				Yes				Yes			
35				35				35			
No				No				No			
0				150				150			
12.1877%				12.1877%				12.1877%			
12.1877%				13.1358%				13.1358%			
13,722,120				26,046,638				18,572,212			
392,061				744,190				530,635			
9.00				7.00				7			
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
12,055,863	392,061	11,663,802	1,813,611	22,759,800	744,190	22,015,611	3,427,389	16,228,576	530,635	15,697,941	2,443,855
12,055,863	392,061	11,663,802	1,813,611	22,759,800	744,190	22,015,611	3,636,126	16,228,576	530,635	15,697,941	2,592,691
11,663,802	392,061	11,271,741	1,765,828	22,015,611	744,190	21,271,421	3,336,689	15,697,941	530,635	15,167,306	2,379,182
11,663,802	392,061	11,271,741	1,765,828	22,015,611	744,190	21,271,421	3,538,370	15,697,941	530,635	15,167,306	2,522,988
11,271,741	392,061	10,879,681	1,718,045	21,271,421	744,190	20,527,231	3,245,990	15,167,306	530,635	14,636,672	2,314,510
11,271,741	392,061	10,879,681	1,718,045	21,271,421	744,190	20,527,231	3,440,614	15,167,306	530,635	14,636,672	2,453,285
10,879,681	392,061	10,487,620	1,670,262	20,527,231	744,190	19,783,042	3,155,290	14,636,672	530,635	14,106,037	2,249,838
10,879,681	392,061	10,487,620	1,670,262	20,527,231	744,190	19,783,042	3,342,859	14,636,672	530,635	14,106,037	2,383,581
10,487,620	392,061	10,095,560	1,622,478	19,783,042	744,190	19,038,852	3,064,590	14,106,037	530,635	13,575,403	2,185,166
10,487,620	392,061	10,095,560	1,622,478	19,783,042	744,190	19,038,852	3,245,103	14,106,037	530,635	13,575,403	2,313,878
10,095,560	392,061	9,703,499	1,574,695	19,038,852	744,190	18,294,662	2,973,891	13,575,403	530,635	13,044,768	2,120,494
10,095,560	392,061	9,703,499	1,574,695	19,038,852	744,190	18,294,662	3,147,348	13,575,403	530,635	13,044,768	2,244,175
9,703,499	392,061	9,311,439	1,526,912	18,294,662	744,190	17,550,473	2,883,191	13,044,768	530,635	12,514,133	2,055,821
9,703,499	392,061	9,311,439	1,526,912	18,294,662	744,190	17,550,473	3,049,592	13,044,768	530,635	12,514,133	2,174,471
9,311,439	392,061	8,919,378	1,479,129	17,550,473	744,190	16,806,283	2,792,491	12,514,133	530,635	11,983,499	1,991,149
9,311,439	392,061	8,919,378	1,479,129	17,550,473	744,190	16,806,283	2,951,837	12,514,133	530,635	11,983,499	2,104,768
8,919,378	392,061	8,527,317	1,431,346	16,806,283	744,190	16,062,093	2,701,791	11,983,499	530,635	11,452,864	1,926,477
8,919,378	392,061	8,527,317	1,431,346	16,806,283	744,190	16,062,093	2,854,081	11,983,499	530,635	11,452,864	2,035,065
8,527,317	392,061	8,135,257	1,383,562	16,062,093	744,190	15,317,904	2,611,092	11,452,864	530,635	10,922,229	1,861,805
8,527,317	392,061	8,135,257	1,383,562	16,062,093	744,190	15,317,904	2,756,325	11,452,864	530,635	10,922,229	1,965,361
8,135,257	392,061	7,743,196	1,335,779	15,317,904	744,190	14,573,714	2,520,392	10,922,229	530,635	10,391,595	1,797,132
8,135,257	392,061	7,743,196	1,335,779	15,317,904	744,190	14,573,714	2,658,570	10,922,229	530,635	10,391,595	1,895,658
7,743,196	392,061	7,351,136	1,287,996	14,573,714	744,190	13,829,524	2,429,692	10,391,595	530,635	9,860,960	1,732,460
7,743,196	392,061	7,351,136	1,287,996	14,573,714	744,190	13,829,524	2,560,814	10,391,595	530,635	9,860,960	1,825,955
7,351,136	392,061	6,959,075	1,240,213	13,829,524	744,190	13,085,335	2,338,993	9,860,960	530,635	9,330,326	1,667,788
7,351,136	392,061	6,959,075	1,240,213	13,829,524	744,190	13,085,335	2,463,059	9,860,960	530,635	9,330,326	1,756,251
6,959,075	392,061	6,567,015	1,192,429	13,085,335	744,190	12,341,145	2,248,293	9,330,326	530,635	8,799,691	1,603,116
6,959,075	392,061	6,567,015	1,192,429	13,085,335	744,190	12,341,145	2,365,303	9,330,326	530,635	8,799,691	1,686,548
6,567,015	392,061	6,174,954	1,144,646	12,341,145	744,190	11,596,955	2,157,593	8,799,691	530,635	8,269,056	1,538,443
6,567,015	392,061	6,174,954	1,144,646	12,341,145	744,190	11,596,955	2,267,547	8,799,691	530,635	8,269,056	1,616,845
....	....	.....	....	....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

nent 7 is 12.80%, which includes a 150 basis-point tranmission

B0277 Cumberland Sub:2nd Xfmr

Yes
35
No
150
12.1877%
13.1358%
6,759,777
193,136
2

Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
6,212,557	193,136	6,019,420	926,766	$ 10,327,721		$ 10,327,721
6,212,557	193,136	6,019,420	983,838	$ 10,782,477	$ 10,782,477	
6,019,420	193,136	5,826,284	903,227	$ 10,056,689		$ 10,056,689
6,019,420	193,136	5,826,284	958,468	$ 10,496,212	$ 10,496,212	
5,826,284	193,136	5,633,148	879,688	$ 9,785,657		$ 9,785,657
5,826,284	193,136	5,633,148	933,098	$ 10,209,946	$ 10,209,946	
5,633,148	193,136	5,440,011	856,149	$ 9,514,625		$ 9,514,625
5,633,148	193,136	5,440,011	907,728	$ 9,923,681	$ 9,923,681	
5,440,011	193,136	5,246,875	832,610	$ 9,243,593		$ 9,243,593
5,440,011	193,136	5,246,875	882,358	$ 9,637,416	$ 9,637,416	
5,246,875	193,136	5,053,738	809,072	$ 8,972,561		$ 8,972,561
5,246,875	193,136	5,053,738	856,988	$ 9,351,151	$ 9,351,151	
5,053,738	193,136	4,860,602	785,533	$ 8,701,529		$ 8,701,529
5,053,738	193,136	4,860,602	831,617	$ 9,064,885	$ 9,064,885	
4,860,602	193,136	4,667,465	761,994	$ 8,430,497		$ 8,430,497
4,860,602	193,136	4,667,465	806,247	$ 8,778,620	$ 8,778,620	
4,667,465	193,136	4,474,329	738,455	$ 8,159,465		$ 8,159,465
4,667,465	193,136	4,474,329	780,877	$ 8,492,355	$ 8,492,355	
4,474,329	193,136	4,281,192	714,916	$ 7,888,433		$ 7,888,433
4,474,329	193,136	4,281,192	755,507	$ 8,206,089	$ 8,206,089	
4,281,192	193,136	4,088,056	691,377	$ 7,617,401		$ 7,617,401
4,281,192	193,136	4,088,056	730,137	$ 7,919,824	$ 7,919,824	
4,088,056	193,136	3,894,919	667,838	$ 7,346,369		$ 7,346,369
4,088,056	193,136	3,894,919	704,767	$ 7,633,559	$ 7,633,559	
3,894,919	193,136	3,701,783	644,299	$ 7,075,337		$ 7,075,337
3,894,919	193,136	3,701,783	679,397	$ 7,347,294	$ 7,347,294	
3,701,783	193,136	3,508,646	620,760	$ 6,804,305		$ 6,804,305
3,701,783	193,136	3,508,646	654,027	$ 7,061,028	$ 7,061,028	
3,508,646	193,136	3,315,510	597,221	$ 6,533,273		$ 6,533,273
3,508,646	193,136	3,315,510	628,657	$ 6,455,913	$ 6,455,913	
....	....	.....	....			$ -
....	.....	.....	....		$ -	
					$ 178,806,346	$ 171,719,168

Atlantic City Electric Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	16,687,316
	Capitalization	
112	**Less LTD on Securitization Bonds**	231,760,646

Calculation of the above Securitization Adjustments

Inputs from Atlantic City Electric Company 2012 FERC Form 1
Pages 256-257 "Long Term Debt (Account 221, 222, 223, and 224)"
Line 25 "Note Payable to ACE Transition Funding - variable"
LTD Interest on Securitization Bonds in column (i)
LTD on Securitization Bonds in column (h)

Attachment 4D - PEPCO Formula Rate Update

Pepco Holdings, Inc

701 Ninth Street, NW
Suite 1100
Washington, DC 20068

Amy L. Blauman
Associate General Counsel

202-872-2122
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May 15, 2013

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, DC 20426

Re: Potomac Electric Power Company ("Pepco")
Informational Filing of 2013 Formula Rate Annual Update in
Docket No. ER09-1159 and Pursuant to Approved Settlement Agreement
in Docket Nos. ER05-515-000, *et al.*

Dear Ms. Bose,

Pepco hereby submits electronically, for informational purposes, its 2013 Annual Formula Rate Update. On April 19, 2006, the Commission approved an uncontested settlement agreement ("Settlement") filed in Docket Nos. ER05-515-000, *et al.*, (115 FERC ¶ 61,066). Formula rate implementation protocols contained in the Settlement provide that:

> [o]n or before May 15 of each year, Pepco [Potomac Electric Power Company] shall recalculate its Annual Transmission Revenue Requirements, producing an "Annual Update" for the upcoming Rate Year, and:

(i) post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page; and

(ii) file such Annual Update with FERC as an informational filing.[1]

The same information contained in this informational filing has been transmitted to PJM for posting on its website as required by the formula rate implementation protocols. Thus, all interested parties should have ample notice of and access to the Annual Update. The protocols provide specific procedures for notice, review, exchanges of information and potential challenges to aspects of the Annual Update. Consequently,

[1] *See* Settlement, Exhibit B-1 containing PJM Tariff Attachment H9-B, Section 1.b.

and as the Commission has concluded, there is no need for the Commission to notice this informational filing for comment.[2]

Pepco's 2013 Annual Update contains no expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices, as defined in 18 C.F.R. § 35.13(b)(7).

In 2012, Pepco adopted revised general plant depreciation rates in its Maryland service territory, by order of the Maryland Public Service Commission.[3] Pepco has made no additional Material Accounting Changes as defined in the Settlement.[4] Pepco has made no change to Other Post-Employment Benefits ("OPEB") charges that exceed the filing threshold set forth in the Settlement.[5] Additionally, Pepco has not recorded any extraordinary property losses in FERC Account 182.1. Therefore, no amortization is required over the periods described in the Settlement.[6]

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Very truly yours,

/s/ Amy L. Blauman

Amy L. Blauman
Associate General Counsel
Potomac Electric Power Company

Enclosures

[2] *See* Letter Order Re: Annual Update to Formula Rate in Docket No. ER09-1159 (February 17, 2010).
[3] *See* MD PSC Order No. 85028 at 81-82.
[4] *See* Settlement, Exhibit B-3 containing PJM Tariff Attachment H-9B, Section 1.f (iii).
[5] *See* Settlement, Exhibit B-3 containing PJM Tariff Attachment H-9B, Section 1.g.
[6] *See* Settlement, Exhibit B-3 containing PJM Tariff Attachment H-9B, Section 1.h.

ATTACHMENT H-9A

Potomac Electric Power Company

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description		Notes	FERC Form 1 Page # or Instruction	2012
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense			p354.21b	$ 5,680,405
2	Total Wages Expense			p354.28b	$ 69,614,640
3	Less A&G Wages Expense			p354.27b	$ 6,282,467
4	Total			(Line 2 - 3)	63,332,173
5	Wages & Salary Allocator			(Line 1 / 4)	8.9692%
	Plant Allocation Factors				
6	Electric Plant in Service		(Note B)	p207.104g	$ 6,288,555,881
7	Common Plant In Service - Electric			(Line 24)	0
8	Total Plant In Service			(Sum Lines 6 & 7)	6,288,555,881
9	Accumulated Depreciation (Total Electric Plant)			p219.29c	$ 2,585,224,257
10	Accumulated Intangible Amortization		(Note A)	p200.21c	$ 102,286,010
11	Accumulated Common Amortization - Electric		(Note A)	p356	0
12	Accumulated Common Plant Depreciation - Electric		(Note A)	p356	0
13	Total Accumulated Depreciation			(Sum Lines 9 to 12)	2,687,510,267
14	Net Plant			(Line 8 - 13)	3,601,045,614
15	Transmission Gross Plant			(Line 29 - Line 28)	1,146,188,083
16	Gross Plant A locator			(Line 15 / 8)	18.2266%
17	Transmission Net Plant			(Line 39 - Line 28)	741,752,716
18	Net Plant Allocator			(Line 17 / 14)	20.5983%
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note B)	p207.58.g	$ 1,089,745,484
20	For Reconci iation only - remove New Transmission Plant Additions for Current Calendar Year		For Reconciliation Only	Attachment 6 - Enter Negative	
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)			Attachment 6	27,191,669
22	Total Transmission Plant In Service			(Line 19 - 20 + 21)	1,116,937,153
23	General & Intangible			p205.5.g & p207.99.g	326,125,511
24	Common Plant (Electric Only)		(Notes A & B)	p356	0
25	Total General & Common			(Line 23 + 24)	326,125,511
26	Wage & Salary Allocation Factor			(Line 5)	8.96922%
27	General & Common Plant Allocated to Transmission			(Line 25 * 26)	29,250,930
28	Plant Held for Future Use (Including Land)		(Note C)	p214	0
29	TOTAL Plant In Service			(Line 22 + 27 + 28)	1,146,188,083
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note B)	p219.25.c	383,719,626
31	Accumulated General Depreciation			p219.28.c	128,678,669
32	Accumulated Intangible Amortization			(Line 10)	102,286,010
33	Accumulated Common Amortization - Electric			(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)			(Line 12)	0
35	Total Accumulated Depreciation			(Sum Lines 31 to 34)	230,964,679
36	Wage & Salary Allocation Factor			(Line 5)	8.96922%
37	General & Common Allocated to Transmission			(Line 35 * 36)	20,715,741
38	TOTAL Accumulated Depreciation			(Line 30 + 37)	404,435,367
39	TOTAL Net Property, Plant & Equipment			(Line 29 - 38)	741,752,716
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109			Attachment 1	-197,632,449
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative	(Notes A & I)	p266.h	0
42	Net Plant Allocation Factor			(Line 18)	20.60%
43	Accumulated Deferred Income Taxes Allocated To Transmission			(Line 41 * 42) + Line 40	-197,632,449
43a	Transmission Related CWIP (Current Year 12 Month weighted average balances)		(Note B)	p216.43.b as Shown on Attachment 6	7,867,175
43b	Unamortized Abandoned Transmission Plant			Attachment 5	39,136,650
	Transmission O&M Reserves				
44	Total Balance Transmission Related Account 242 Reserves		Enter Negative	Attachment 5	-4,800,161
	Prepayments				
45	Prepayments		(Note A)	Attachment 5	33,917,355
46	Total Prepayments Allocated to Transmission			(Line 45)	33,917,355
	Materials and Supplies				
47	Undistributed Stores Exp		(Note A)	p227.6c & 16.c	3,659,920
48	Wage & Salary Allocation Factor			(Line 5)	8.97%
49	Total Transmission Allocated			(Line 47 * 48)	328,266
50	Transmission Materials & Supplies			p227.8c	5,552,845
51	Total Materials & Supplies Allocated to Transmission			(Line 49 + 50)	5,881,111
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 85)	40,636,820
53	1/8th Rule			x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission			(Line 52 * 53)	5,079,602
	Network Credits				
55	Outstanding Network Credits		(Note N)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits		(Note N)	From PJM	0
57	Net Outstanding Credits			(Line 55 - 56)	0
58	TOTAL Adjustment to Rate Base			(Line 43 + 43a + 43b + 44 + 46 + 51 + 54 - 57)	-110,550,715
59	Rate Base			(Line 39 + 58)	631,202,000

O&M

	Transmission O&M			
60	Transmission O&M		p321.112.b	28,381,112
61	Less extraordinary property loss		Attachment 5	0
62	Plus amortized extraordinary property loss		Attachment 5	0
63	Less Account 565		p321.96.b	0
64	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note O)	PJM Data	0
65	Plus Transmission Lease Payments	(Note A)	p200.3.c	0
66	Transmission O&M		(Lines 60 - 63 + 64 + 65)	28,381,112
	Allocated General & Common Expenses			
67	Common Plant O&M	(Note A)	p356	0
68	Total A&G		p323.197.b	141,620,834
69	Less Property Insurance Account 924		p323.185b	1,038,577
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	2,816,919
71	Less General Advertising Exp Account 930.1		p323.191b	3,508,711
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b	0
73	Less EPRI Dues	(Note D)	p352-353	0
74	General & Common Expenses		(Lines 67 + 68) - Sum (69 to 73)	134,256,627
75	Wage & Salary Allocation Factor		(Line 5)	8.9692%
76	General & Common Expenses Allocated to Transmission		(Line 74 * 75)	12,041,779
	Directly Assigned A&G			
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	0
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	0
79	Subtotal - Transmission Related		(Line 77 + 78)	0
80	Property Insurance Account 924		p323.185b	1,038,577
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	0
82	Total		(Line 80 + 81)	1,038,577
83	Net Plant Allocation Factor		(Line 18)	20.60%
84	A&G Directly Assigned to Transmission		(Line 82 * 83)	213,929
85	Total Transmission O&M		(Line 66 + 76 + 79 + 84)	40,636,820

Depreciation & Amortization Expense

	Depreciation Expense			
86	Transmission Depreciation Expense		p336.7b&c	23,030,856
86a	Amortization of Abandoned Transmission Plant		Attachment 5	7,827,330
87	General Depreciation		p336.10b&c	10,271,751
88	Intangible Amortization	(Note A)	p336.1d&e	4,161,139
89	Total		(Line 87 + 88)	14,432,890
90	Wage & Salary Allocation Factor		(Line 5)	8.9692%
91	General Depreciation Allocated to Transmission		(Line 89 * 90)	1,294,518
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0
94	Total		(Line 92 + 93)	0
95	Wage & Salary Allocation Factor		(Line 5)	8.9692%
96	Common Depreciation - Electric Only Allocated to Transmission		(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization		(Line 86 + 86a + 91 + 96)	32,152,704

Taxes Other than Income

98	Taxes Other than Income		Attachment 2	8,760,657
99	Total Taxes Other than Income		(Line 98)	8,760,657

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	102,364,544
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
102	Long Term Interest			"(Line 100 - line 101)"	102,364,544
103	Preferred Dividends		enter positive	p118.29c	-
	Common Stock				
104	Proprietary Capital			p112.16c	$ 1,643,194,429
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	-1,646,367
107	Common Stock			(Sum Lines 104 to 106)	1,641,548,062
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,709,625,038
109	Less Loss on Reacquired Debt		enter negative	p111.81c	-27,611,354
110	Plus Gain on Reacquired Debt		enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	35,040
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
113	Total Long Term Debt			(Sum Lines 108 to 112)	1,682,048,724
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,641,548,062
116	Total Capitalization			(Sum Lines 113 to 115)	3,323,596,786
117	Debt %	Total Long Term Debt		(Line 113 / 116)	51%
118	Preferred %	Preferred Stock		(Line 114 / 116)	0%
119	Common %	Common Stock		(Line 115 / 116)	49%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0609
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J)	Fixed	0.1130
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0308
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0558
126	Total Return (R)			(Sum Lines 123 to 125)	0.0866
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)	54,668,929

Composite Income Taxes

	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite		(Note I)		9.00%
130	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
132	T/ (1-T)				69.06%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	p266.8f	-1,319,472
134	T/(1-T)			(Line 132)	69.06%
135	Net Plant Allocation Factor			(Line 18)	20.5983%
136	ITC Adjustment Allocated to Transmission			(Line 133 * (1 + 134) * 135)	-459,481
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	24,328,104
138	Total Income Taxes			(Line 136 + 137)	23,868,623

REVENUE REQUIREMENT

	Summary			
139	Net Property, Plant & Equipment		(Line 39)	741,752,716
140	Adjustment to Rate Base		(Line 58)	-110,550,715
141	Rate Base		(Line 59)	631,202,000
142	O&M		(Line 85)	40,636,820
143	Depreciation & Amortization		(Line 97)	32,152,704
144	Taxes Other than Income		(Line 99)	8,760,657
145	Investment Return		(Line 127)	54,668,929
146	Income Taxes		(Line 138)	23,868,623
147	Gross Revenue Requirement		(Sum Lines 142 to 146)	160,087,732
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	1,089,745,484
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	1,089,745,484
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	160,087,732
153	Adjusted Gross Revenue Requirement		(Line 151 * 152)	160,087,732
	Revenue Credits & Interest on Network Credits			
154	Revenue Credits		Attachment 3	6,190,851
155	Interest on Network Credits	(Note N)	PJM Data	-
156	Net Revenue Requirement		(Line 153 - 154 + 155)	153,896,882
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	153,896,882
158	Net Transmission Plant		(Line 19 - 30)	706,025,858
159	Net Plant Carrying Charge		(Line 157 / 158)	21.7976%
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	18.5356%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	7.4117%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	75,359,330
163	Increased Return and Taxes		Attachment 4	83,808,033
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	159,167,363
165	Net Transmission Plant		(Line 19 - 30)	706,025,858
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	22.5441%
167	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 163 - 86) / 165	19.2821%
168	Net Revenue Requirement		(Line 156)	153,896,882
169	True-up amount		Attachment 6	968,119
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	1,494,234
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515		Attachment 5	-
172	Net Zonal Revenue Requirement		(Line 168 - 169 + 171)	156,359,235
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	6,721
174	Rate ($/MW-Year)		(Line 172 / 173)	23,265
175	Network Service Rate ($/MW/Year)		(Line 174)	23,265

Notes

A Electric portion only
B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in the PJM Regional Transmission Plan (RTEP) must be separately detailed on Attachment 5. For the Reconc liation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).
C Transmission Portion Only
D A l EPRI Annual Membership Dues
E A l Regulatory Commission Expenses
F Safety related advertising included in Account 930.1
G Regulatory Commission Expenses directly related to transmission service, RTO fi ings, or transmission siting itemized in Form 1 at 351.h.
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 ut lity 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 ut lity 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. ER08-10, the ROE is 11.30%, which includes a 50 basis-point RTO membership adder as authorized by FERC to become effective on December 1, 2007. Per FERC orders in Docket Nos. ER08-686 and ER08-1423, the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point transmission incentive ROE adder as authorized by FERC to become effective June 1, 2008 and November 1, 2008 respectively. Per FERC order in Docket No. ER13-607 the ROE for the MAPP abandoned plant is 10.8% effective March 1, 2013.
K Education and outreach expenses relating to transmission, for example siting or bil ing
L As provided for in Section 34.1 of the PJM OATT and the PJM established billing determinants will not be revised or updated in the annual rate reconc liations per settlement in ER05-515.
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) 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 Transmisison Owner whole on Line 155.
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 in on line 64
P Securitization bonds may be included in the capital structure per settlement in ER05-515.
Q ACE capital structure is initially fixed at 50% common equity and 50% debt per settlement in ER05-515 subject to moratorium provisions in the settlement.
R Per the settlement in ER05-515, the facility credits of $15,000 per month paid to Vineland will increase to $37,500 per month (prorated for partial months) effective on the date FERC approves the settlement in ER05-515.

END

Potomac Electric Power Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	(1,022,103,284)	(9,734,590)	
ADIT-283	(16,826,536)	(108,651,718)	(104,147,450)	
ADIT-190	985,023	178,384,710	22,385,928	
Subtotal	(15,841,512)	(952,370,291)	(91,496,112)	
Wages & Salary Allocator			8.9692%	
Gross Plant Allocator		18.2266%		
ADIT	(15,841,512)	(173,584,444)	(8,206,492)	(197,632,449)

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 111

Amount (35,040)

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E 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*
Deferred Compensation(stk)	4,140,878				4,140,878	For book purposes, deferred compensation and deferred payments are expensed when accrued. For tax purposes, they are deducted when paid. Affects company personnel across all functions.
Bad Debt Reserve Amort	5,706,722			5,706,722		Under the Tax Reform Act of 1986, taxpayers were required to switch from the reserve method for bad debts to the specific write-off method. The amounts previously accumulated in a reserve were required to be included in taxable income over a four year period. The reserve method is used for book purposes. Related to all revenues.
Excess Accrued Vacation Pay	2,477,033				2,477,033	For book purposes, accrued vacation pay is expensed during the current year. For tax purposes, only the portion of the vacation allowance actually taken or paid by March 15th of the following year can be deducted currently. Affects company personnel across all functions.
FAS 109 - Deferred Taxes on ITC	1,487,374			1,487,374		Pursuant to the requirements of FAS 109, Pepco's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant.
FAS 109 Regulatory Receivable/Liability	2,844,570			2,844,570		Pursuant to the requirements of FAS 109, Pepco's accumulated deferred taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances primarily represent the deferred taxes on prior flow-through items, including the amount of the required gross-up necessary for full recovery of the prior flow-through amount. Related to all plant.
PG County Right of Way	451,318	451,318				For book purposes, these taxes were accrued when the proposed tax was enacted by the PG County Council. Since Maryland counties are prohibited from enacting any tax without the authority of the state legislature, for tax purposes they are not deductible until the tax is affirmed. Related to both T & D.
Mirant Settlement	4,104,266	4,104,266				Represents a payment from Mirant to Pepco to settle some of the Company's claims. For book purposes the payment was accounted for on the balance sheet as a contingent liablilty. For tax purposes, since the funds were received, a portion of the payment was treated as currently taxable.
Health Care Plans	1,074,681			1,074,681		Additions to the reserve for health insurance payments are deducted currently for book purposes but are deducted for tax purposes when they are paid. Affects company personnel across all functions.
Severance Pay/Other Comp/Incentive Bonus	3,040,925				3,040,925	For book purposes, the costs are expensed when a formal plan is adopted and the employees to be severed have been identified. For tax purposes, the costs are deductible when they are paid to the severed individual. Affects company personnel across all functions.
Accrued Retired Executive Compensation	1,213,275				1,213,275	PHI's consolidated return is in an NOL situation, therefore, Pepco's charitable contributions are carried forward until such time as PHI is in a taxable income position. For book purposes, the contributions are expensed when incurred. Related to all functions.
Accrued Liability - Environmental Site Exp	6,512,585	6,512,585				For book purposes, environmental expenses are expensed when accrued. For tax purposes, they are deducted when paid.
Prepaid Interest	1,592,727				1,592,727	For book purposes, prepaid expenses, which related to a future period but are paid in the current period, must be capitalzied and amortized to the balance sheet as an assset. For tax purposes, there is "12-month rule" which allows taxpayers that meet the 12-month rule to currently deduct the amount, as long as the benefits does not extend beyond 12 months. The prepaid interest relates to the Life Insurance plans, that is why this is labor related.
Contribution Carryforward	4,550,844			4,550,844		PHI's consolidated return is in an NOL situation, therefore, Pepco's charitable contributions are carried forward until such time as PHI is in a taxable income position. For book purposes, the contributions are expensed when incurred. Related to all functions.
Capital Loss Limitation	(6,535)	(6,535)				Capital losses are limited to the amount of capital gains.
FAS 106 OPEB Adjustment	35,830,640				35,830,640	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
Regulatory Assets- FERC True Up	985,023		985,023			For book purposes, a regulatory asset has been established for the FERC Formula Rate Filing true-up and book income has been increased. For tax purposes, this Regulatory Asset is not recognized and the book income must be reversed.
Miscellaneous	802,438	(60,824)		863,263		See the explanation for Account 190.
Federal/State NOL	176,110,290			166,189,200	9,921,090	PHI's consolidated return is in an NOL situation, therefore, they are carried forward until such time as PHI is in a taxable income position.
Subtotal - p234	252,919,055	11,000,809	985,023	182,716,655	58,216,568	
Less FASB 109 Above if not separately removed	4,331,945	-	-	4,331,945		
Less FASB 106 Above if not separately removed	35,830,640		-		35,830,640	
Total	212,756,471	11,000,809	985,023	178,384,710	22,385,928	

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

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Potomac Electric Power Company

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*
Accelerated Depreciation	(380,572,982)			(380,572,982)		This amount represents the difference between the tax depreciation on assets place in service after 1974 as computed pursuant to the Internal Revenue Code and the book depreciation associated with all assets.
Repair Allowance	(327,637,104)			(327,637,104)		Deferred tax represents the difference between tax deductible repairs and book capitalization of repair costs. Affects company personnel across all functions.
Adj. Tax Gain - TDR's	871,366			871,366		This adjustment reflects the disposition or salvage relating to TDRs. For tax purposes salvage is required to be recognized currently as taxable income for certain depreciation vintages. For book purposes salvage is credited to the depreciation reserve. Relates to plant in all functions.
Adjust. Tax Gain (Operating)	(4,967,240)			(4,967,240)		This adjustment reflects the disposition or salvage relating to operating assets. For tax purposes salvage is required to be recognized currently as taxable income for certain depreciation vintages. For book purposes salvage is credited to the depreciation reserve. Related to all assets.
Control Center - Depreciation/Amort	(95,164,895)			(95,164,895)		See the explanation for Account 190.
Removal Cost Adjustment	(53,453,498)			(53,453,498)		Removal costs are deductible for tax purposes but are recorded as a reduction to the depreciation reserve for book purposes. Removal costs relating to post-1980 assets are required to be normalized under the Internal Revenue Code. Related to all assets.
Capitalized Interest	34,723,120			34,723,120		The Tax Reform Act of 1986 eliminated the current deduction for interest incurred during construction and required that it be capitalized and depreciated over the tax life of the asset. This deferred tax is due to the differences in the way AFUDC-debt is calculated versus the way interest must be calculated for tax purposes. Related to all plant.
AFUDC Debt	(5,057,563)			(5,057,563)		For book purposes, AFUDC is capitalized and depreciated. For tax purposes, AFUDC is not recognized. Related to all plant.
Capitalized Real Estate Taxes	(7,809)			(7,809)		For book purposes, certain real estate taxes were expensed. For tax purposes, those taxes were capitalized and are being depreciated. Related to all plant.
Extraordinary Gain-Nova	(8,303,806)	(8,303,806)				This deferred tax balance relates to a prior Internal Revenue Service audit related to the sale of Pepco's northern Virginia sales territory and assets located therein. Retail related
Construction Per. Interest(Net)	264,333			264,333		For tax purposes some interest was required to be capitalized related to self constructed assets. For book purposes, AFUDC is used. Related to all plant.
FAS 109 - CCRF/AFUDC Equity	(42,120,779)			(42,120,779)		See the explanation for Account 190.
69 KV Line Amortization	218,609	218,609				This deferred tax balance relates to a prior Internal Revenue Service audit related to the depreciation period for 69kv line costs. Distribution related.
Simplified Service Method	(310,312,587)			(310,312,587)		For book purposes, certain overhead costs are capitalized and depreciated over the life of the related asset. For tax purposes, these overheads are currently deducted. Related to all plant.
EUM Assets	6,253,612	6,253,612				This deferred tax balance relates to a prior Internal Revenue Service audit related to the depreciation of Energy Use Mgt. assets. Retail related
Casualty Losses	(19,253,489)			(19,253,489)		This deferred tax balance relates to the run out of the depreciation expense related to the 1998 casualty loss claim filed with the IRS. This item was previously included in depreciation above.
Control Center - Lease Payment	111,344,058			111,344,058		For book purposes, the rental payments on the control center are expensed during the current year. For tax purposes, control center is treated as if Pepco continues to own it. The rent expense is added back to book income, the assets are depreciated and interest expense is imputed and deducted. Sale/lease back of center used for control of T & D.
CIAC	78,579,093			78,579,093		Under the Tax Reform Act of 1986, post '86 CIAC must be included in income for tax purposes. Under IRS Notice 87-51, if CIAC are not grossed up, the deferred taxes must be included in rate base in order for the Company to be in compliance with the depreciation normalization provisions of the Internal Revenue Code. Related to both T & D plant.
Connection Fees	(2,891,115)	(2,891,115)				Connection fees are considered taxable income by the Internal Revenue Service and their costs are capitalized and depreciated for tax purposes. For book purposes, connection fees are excluded from income and from the depreciable cost of the assets as a contribution in aid of construction. Retail related.
Preliminary Survey Costs	50,773	50,773				For tax purposes, survey costs are to be capitalized under 263A and depreciated.
Conservation Costs (DSM)	(11,325,757)	(11,325,757)				DSM related. Retail related.
Pension Curtailment	3,496,754	3,496,754				For book purposes, these costs were expensed when the gain on the divestiture sale were recorded. For tax purposes, the costs are deducted when paid. Related to sale of generation assets.
SFAS 121 Impairment Loss	859,870	859,870				Write down of Benning/Buzzard point plant to fair market value based on the SFAS 121 impairment test for book purposes. For tax purposes, an asset can not be written down for the loss. Generation related.
Capitalized A&G	1,116,576			1,116,576		Prior to the Tax Reform Act of 1986, these amounts were deducted in the year incurred for tax purposes, but capitalized and depreciated for book purposes. Related to all plant.
Capit'd Fringe Benefits	2,136,059			2,136,059		Prior to the Tax Reform Act of 1986, these amounts were deducted in the year incurred for tax purposes, but capitalized and depreciated for book purposes. Related to all plant.
Capit'd Payroll & Use Tax	1,067,746			1,067,746		Prior to the Tax Reform Act of 1986, these amounts were deducted in the year incurred for tax purposes, but capitalized and depreciated for book purposes. Related to all plant.
Leased Vehicles	(5,797,488)			(5,797,488)		For tax purposes leased vehicles are capitalized and depreciated. For book purposes, the vehicles are treated as leases, with a monthly lease amount being calculated. For tax purposes, a portion of the monthly lease amount needs to be added back.
Control Center - Interest Expense	(76,461,287)			(76,461,287)		See the explanation for the control center transaction in Account 190.
FAS 109 - CCRF Equity	(15,743,143)	(15,743,143)				See the explanation for Account 190.
Capitalized Pension	26,480,307			26,480,307		For book purposes, a portion of pension is capitalized based on labor dollars charged to capital construction projects. For tax purposes, this capitalization must be revrsed and replaced with tax capitalization. Tax capitalization is based on the same capitalization percentage, but is applied to the current period funding rather the ant the book expesnes.
Capitalized OPEB	(9,734,590)				(9,734,590)	For book purposes, a portion of OPEB is capitalized based on labor dollars charged to capital construction projects. For tax purposes, this capitalization must be revrsed and replaced with tax capitalization. Tax capitalization is based on the same capitalization percentage, but is applied to the current period funding rather the ant the book expesnes.
Subtotal - p275 (Form 1-F filer: see note 6 below)	(1,101,342,856)	(27,384,203)	0	(1,064,224,063)	(9,734,590)	
Less FASB 109 Above if not separately removed	(57,863,923)	(15,743,143)	0	(42,120,779)	0	
Less FASB 106 Above if not separately removed	0					
Total	(1,043,478,934)	(11,641,060)	0	(1,022,103,284)	(9,734,590)	

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

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Potomac Electric Power Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT-283	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Bk Depr on Poll Bond Int	(106,361)	(106,361)				Generation related.
Amort Loss on Reacquisition	(35,040)	(35,040)				The cost of bond redemption is deductible currently for tax purposes and is amortized over the life of the new bond issue for book purposes. Related to all functions.
Loss on Marketable Securities	(9,640,593)	(9,640,593)				The deferred tax balance reflects the difference between the book gain and tax gain on the disposition/salvage of marketable securities.
FAS 109 - Flowthrough Items	(30,616,211)			(30,616,211)		See the explanation for Account 190.
Pension Plan Contribution	(136,677,925)			(60,138,288)	(76,539,637)	The company is allowed to deduct for tax purposes all payments made to fund the General Retirement Plan per ERISA. For book purposes pension plan contributions are governed by FAS 106. This timing difference represents the excess tax payment over book. Affects company personnel across all functions.
Miscellaneous	(2,052,169)	(2,052,169)				See the explanation for Account 190.
Customer Sharing	(2,875,643)	(2,875,643)				For book purposes, the gain on the divestiture of the generating assets to be shared with customers was expensed when the gain on the sale was recorded. For tax purposes, gain to be shared is deducted when paid. Generation related
Blueprint for the Future	(1,196,974)			(1,196,974)		For book purposes, the cost of the Blueprint project is being currently deducted. For tax purposes, this amount can not be deducted current and must be capitalized.
Regulatory Assets- FERC True Up	(2,748,039)		(2,748,039)			For book purposes, a regulatory asset has been established for the FERC Formula Rate Filing true-up and book income has been increased. For tax purposes, this Regulatory Asset is not recognized and the book income must be reversed.
Regulatory Assets - MAPP - Transmission Only	(14,078,497)		(14,078,497)			This regulatory asset represents MAPP adbandonment cost with no potential future value other than through rate recovery; it is considered worthless for tax purposes and is deductible under IRC Section 165(a)as an abandonment loss.
Regulatory Assets	(97,245,892)	(22,321,623)		(47,316,456)	(27,607,813)	When a regulatory asset is established, books credits income, which for tax purposes needs to be reversed along with the associated amortization.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(297,273,344)	(37,031,430)	(16,826,536)	(139,267,928)	(104,147,450)	
Less FASB 109 Above if not separately removed	(30,616,211)			(30,616,211)		
Less FASB 106 Above if not separately removed	-				-	
Total	(266,657,133)	(37,031,430)	(16,826,536)	(108,651,718)	(104,147,450)	

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
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Potomac Electric Power Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

		Item	Balance	Amortization
1	Rate Base Treatment			
2	Balance to line 41 of Appendix A	Total		
3	Amortization			
4	Amortization to line 133 of Appendix A	Total	3,678,420	1,319,472
5	Total		3,678,420	1,319,472
6	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.2	3,678,420	1,319,472
7	Difference /1		-	-

/1 Difference must be zero

Potomac Electric Power Company

Attachment 2 - Taxes Other Than Income Worksheet

Other Taxes		*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
Plant Related			***Gross Plant Allocator***	
1	Transmission Personal Property Tax (directly assigned to Transmission)	$ 8,290,484	100%	$ 8,290,484
1a	Other Personal Property Tax (excluded)	$ 26,762,571	0%	$ -
2	Capital Stock Tax		18.2266%	$ -
3	Gross Premium (insurance) Tax		18.2266%	$ -
4	PURTA		18.2266%	$ -
5	Corp License		18.2266%	$ -
			18.2266%	$ -
Total Plant Related		35,053,055		8,290,484
Labor Related			***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & state unemployment	5,242,068		
Total Labor Related		5,242,068	8.9692%	470,173
Other Included			***Gross Plant Allocator***	
7	Miscellaneous	0		
Total Other Included		0	18.2266%	0
Total Included				8,760,657

Currently Excluded

8	Franchise	0
9	kWhTax - State Gross Receipt (Excise Tax)	105,708,003
10	Electric environmental surcharge	2,135,210
11	Universal service fee	8,642,646
12	Montgomery County Fuel	160,274,064
13	PSC assessment	7,671,456
14	Real property (State, Municipal or Local)	6,685,401
15	DC Right of Way	21,799,535
16	Use & Sales Tax	4,051,007
17	FHUT	0
18	DC Ballpark	16,500
19	DC Reliable Energy Trust Fund	17,543,721
20	Misc. Other	19,155
21	Total "Other" Taxes (included on p. 263)	374,841,821
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	374,841,821
23	Difference	0

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be 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

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Allocation of Property taxes to Transmission Function
Year Ended December 31, 2012

Assessable Plant

Transmission	$	770,209,975
Distribution	$	2,413,486,850
General	$	117,327,525
Total T,D&Genl	$	3,301,024,350

Plant ratios by Jurisdiction

Transmission Ratio	0.2333245360
Distribution ratio	0.7311327013
General Ratio	0.0355427627
	1.0000000000

Property Taxes	$	35,053,055

Transmission Property Tax	$	8,178,738
Distribution Property tax	$	25,628,435
General Property Tax	$	1,245,882
Total check	$	35,053,055

General Property Tax	$	1,245,882
Trans Labor Ratio		8.969%
Trans General		111,746

Total Transmission Property Taxes

Transmission	$	8,178,738
General	$	111,746
Total Transmission Property Taxes	$	8,290,484

Potomac Electric Power Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		11,220,158
2	Total Rent Revenues	(Sum Lines 1)	11,220,158
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 598,604
4	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) (Note 4)		
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		2,273,820
6	PJM Transitional Revenue Neutrality (Note 1)		
7	PJM Transitional Market Expansion (Note 1)		
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	14,092,581
12	Less line 17g		(7,901,731)
13	Total Revenue Credits		6,190,851

Revenue Adjustment to determine Revenue Credit

14 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 173 of Appendix A.

15 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.

16 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). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, 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).

17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	11,220,158
17b	Costs associated with revenues in line 17a	4,583,303
17c	Net Revenues (17a - 17b)	6,636,855
17d	50% Share of Net Revenues (17c / 2)	3,318,428
17e	Costs associated with revenues in line 17a 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.	-
17f	Net Revenue Credit (17d + 17e)	3,318,428
17g	Line 17f less line 17a	(7,901,731)
18	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 is 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.	57,940,283
19	Amount offset in line 4 above	138,543,976
20	Total Account 454, 456 and 456.1	210,576,840
21	Note 4: SECA revenues booked in Account 447.	

Potomac Electric Power Company

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 127 + Line 138)	83,808,033
B	100 Basis Point increase in ROE			1 00%
	Return Calculation			
59	Rate Base		(Line 39 + 58)	631,202,000
	Long Term Interest			
100	**Long Term Interest**		p117.62c through 67c	102,364,544
101	Less LTD Interest on Securitization B (Note P)		Attachment 8	0
102	Long Term Interest		"(Line 100 - line 101)"	102,364,544
103	Preferred Dividends	enter positive	p118.29c	0
	Common Stock			
104	Proprietary Capital		p112.16c	1,643,194,429
105	Less Preferred Stock	enter negative	(Line 114)	0
106	Less Account 216.1	enter negative	p112.12c	-1 646 367
107	Common Stock		(Sum Lines 104 to 106)	1,641,548,062
	Capitalization			
108	Long Term Debt		p112.17c through 21c	1,709,625,038
109	Less Loss on Reacquired Debt	enter negative	p111.81c	-27,611,354
110	Plus Gain on Reacquired Debt	enter positive	p113.61c	0
111	Less ADIT associated with Gain or Loss	enter negative	Attachment 1	35,040
112	Less LTD on Securitization Bonds	enter negative	Attachment 8	0
113	Total Long Term Debt		(Sum Lines 108 to 112)	1,682,048,724
114	Preferred Stock		p112.3c	0
115	Common Stock		(Line 107)	1 641 548 062
116	Total Capitalization		(Sum Lines 113 to 115)	3,323,596,786
117	Debt %	Total Long Term Debt	(Line 113 / 116)	51%
118	Preferred %	Preferred Stock	(Line 114 / 116)	0%
119	Common %	Common Stock	(Line 115 / 116)	49%
120	Debt Cost	Total Long Term Debt	(Line 102 / 113)	0.0609
121	Preferred Cost	Preferred Stock	(Line 103 / 114)	0.0000
122	Common Cost (Note J from Appendix A)	Common Stock	Appendix A % plus 100 Basis Pts	0.1230
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 117 * 120)	0.0308
124	Weighted Cost of Preferred	Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock	(Line 119 * 122)	0.0608
126	Total Return (R)		**(Sum Lines 123 to 125)**	**0.0915**
127	Investment Return = Rate Base * Rate of Return		**(Line 59 * 126)**	**57,786,480**
	Composite Income Taxes			
	Income Tax Rates			
128	FIT=Federal Income Tax Rate			35 00%
129	SIT=State Income Tax Rate or Composite			9 00%
130	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0 00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40 85%
132	T/ (1-T)			69 06%
	ITC Adjustment			
133	Amortized Investment Tax Credit	enter negative	p266.8f	(1,319,472)
134	T/(1-T)		(Line 132)	69%
135	Net Plant Allocation Factor		(Line 18)	20 5983%
136	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-459,481**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		26,481,033
138	**Total Income Taxes**			**26,021,553**

Potomac Electric Power Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	$ 102,286,010	102,286,010	0	Respondent is Electric Utility only.
11	Accumulated Common Amortization - Electric	(Note A)	p356	0	0	0	
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	0	0	0	
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	$ 3,678,420	3,678,420	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	$ 3,659,920	3,659,920	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses						
65	Plus Transmission Lease Payments	(Note A)	p200.3.c				
67	Common Plant O&M	(Note A)	p356	0	0	0	
	Depreciation Expense						
88	Intangible Amortization	(Note A)	p336.1d&e	$ 4,161,139	4,161,139	0	Respondent is Electric Utility only.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0	0	0	
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0	0	0	

Transmission / Non-transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	$ 22,002,101	0	22,002,101	Specific identification based on plant records: The following plant investments are included:
	Directly Assigned A&G						
73	Regulatory Commission Exp Account 928	(Note C)	p323.189b	$ 2,816,919	0	2,816,919	Enter Details
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	$ 6,288,555,881	0	0	See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	$ 1,089,745,485	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$ 383,719,626	0	0	See Form 1

EPRI Dues Cost Support

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

Potomac Electric Power Company

Attachment 5 - Cost Support

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
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$ 2,816,919	0	2,816,919	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	$ 2,816,919	0	2,816,919	FERC

Safety Related Advertising Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	$ 3,508,711	-	3,508,711	None

MultiState Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				Maryland	DC	Enter State	Enter State	Enter State	Enter Calculation
129	SIT=State Income Tax Rate or Composite	(Note I)	8.998%	8.25%	9.975%	Enter %	Enter %	Enter %	Apportioned: MD 4.65%, DC 4.37%

Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	$ 3,508,711	0	3,508,711	None

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				
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0	General Description of the Facilities
	Instructions:			Enter $	None
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,			Or	
	the following formula will be used:	Example		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

Potomac Electric Power Company

Attachment 5 - Cost Support

Transmission Related Account 242 Reserves

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Total	Allocation	Transmission Related	Details
44	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)	Enter $		Amount	
	Directly Assignable to Transmission	-	100%	-	
	Labor Related, General plant related or Common Plant related	45,943,491	8.97%	4,120,775	
	Plant Related	3,727,447	18.23%	679,386	
	Other		0.00%	-	
	Total Transmission Related Reserves	49,670,938		4,800,161	

Prepayments

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			To Line 45	Description of the Prepayments
45	Prepayments			To Line 45	
5	Wages & Salary Allocator		8.969%		
	Pension Liabilities, if any, in Account 242	-	8.969%	-	
	Prepayments	$ 25,125,328	8.969%	2,253,547	
	Prepaid Pensions if not included in Prepayments	$ 353,027,254	8.969%	31,663,808	
		378,152,582	8.97%	33,917,355	

Outstanding Network Credits Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Outstanding Network Credits	Description of the Credits
	Network Credits			Enter $	
55	Outstanding Network Credits	(Note N)	From PJM	0	General Description of the Credits
					None
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0	
					None
					Add more lines if necessary

Extraordinary Property Loss

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Number of years	Amortization	w/ interest
61	Less extraordinary property loss	Attachment 5	$ -			
62	Plus amortized extraordinary property loss	Attachment 5	$ -	5	$ -	$ -

Potomac Electric Power Company

Attachment 5 - Cost Support

Interest on Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Interest on Network Credits	Description of the Interest on the Credits
	Revenue Credits & Interest on Network Credits				
155	Interest on Network Credits	(Note N)	PJM Data	0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & PJM Documentation
	Net Revenue Requirement		
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits to Vineland per settlement in ER05-515	-	

PJM Load Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
173	1 CP Peak	(Note L)	PJM Data	6,720.7	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
Pepco zone				-	-	-
Total				-	-	-

Abandoned Transmission Plant

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						
			Project	MAPP Abandonment			Total
			FERC Order	ER13-607	ER13-607	Total	
A	Total Balance of Unamortized Abandoned Plant		Per FERC Order	45,566,000	2,795,959	48,361,959	
B	Percentage allowed by FERC Order		Per FERC Order	100%	50%		
C	Beginning Balance of Allowed Unamortized Abandoned Plant		A*B	45,566,000	1,397,980	46,963,980	
D	Months Remaining in Amortization Period			60	60		
E	Months in Year to be Amortized		# Months	10	10		
F	Amortization in Rate Year	to 86a in Attachment H	C/D*E	7,594,333	232,997	7,827,330	
G	Additions (Deductions)		Worksheet	-	-	-	
H	End of Year Balance in Unamortized Transmission Plant	to 43b in Attachment H	C-F+G	37,971,667	1,164,983	39,136,650	
	Line G deduction include proceeds from the sale of abanded assets , land, or land rights						

Potomac Electric Power Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non-Regulated	Total
Executive Management	$ 10,319,368	$ 8,778,179	$ 19,411,471	$ 4,732,311	$ 43,241,329
Procurement & Administrative Services	6,800,125	5,117,604	11,142,880	1,168,548	24,229,157
Financial Services & Corporate Expenses	13,119,301	10,095,632	19,784,530	2,113,560	45,113,024
Insurance Coverage and Services	2,722,299	2,318,184	3,992,693	1,182,610	10,215,785
Human Resources	4,842,098	3,325,597	7,918,949	1,098,248	17,184,892
Legal Services	3,696,208	2,776,662	6,956,240	521,371	13,950,480
Audit Services	889,689	686,619	1,654,755	194,081	3,425,144
Customer Services	50,035,762	39,174,928	27,817,940	9,258	117,037,888
Utility Marketing Services	366,622	328,711	630,571	-	1,325,904
Information Technology	16,578,099	12,158,126	38,724,477	419,276	67,879,979
External Affairs	2,615,303	2,177,747	5,210,186	465,886	10,469,122
Environmental Services	1,360,579	1,119,104	1,973,001	148,481	4,601,165
Safety Services	388,220	368,439	633,768	-	1,390,427
Regulated Electric & Gas Delivery	27,135,040	20,392,061	40,410,791	1,086	87,938,979
Energy Business	-	-	-	3,902	3,902
Internal Consulting Services	236,486	183,469	712,652	-	1,132,607
Interns	80,850	40,490	165,202	-	286,541
Cost of Benefits	11,931,169	7,425,942	18,880,059	3,008,206	41,245,375
Building Services	8,336	94,433	4,845,257	-	4,948,027
Total	**$ 153,125,554**	**$ 116,561,926**	**$ 210,865,421**	**$ 15,066,825**	**$ 495,619,726**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2012

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Potomac Electric Power Company	66,537,297	144,074,045	254,079	210,865,421
2	Delmarva Power & Light Company	39,129,111	113,813,964	182,479	153,125,554
3	Atlantic City Electric Company	24,278,507	92,144,935	138,484	116,561,926
4	Pepco Energy Services, Inc.	3,241,220	8,643,664	15,330	11,900,214
5	Conectiv, LLC	51,957	790,021	2,094	844,072
6	Potomac Capital Investment Corporation	247,670	319,705	904	568,279
7	Thermal Energy Limited Partnership	19,186	526,060	716	545,962
8	ATS Operating Services, Inc.	141	273,158	312	273,611
9	Atlantic Southern Properties, Inc.	18,351	243,366	390	262,107
10	Conectiv Energy Supply, Inc.	39,953	147,691	1,059	188,703
11	Pepco Holdings, Inc.	112,705	64,916	499	178,120
12	Conectiv Properties and Investment, Inc.	36,456	132,037	221	168,714
13	Conectiv Thermal Systems, Inc.	5,562	93,841	115	99,518
14	Conectiv Communications, Inc.	95	11,553	20	11,668
15	Atlantic City Electric Transition Funding, LLC	4,111	2,728	4	6,843
16	Conectiv North East, LLC	256	4,953	8	5,217
17	Delaware Operating Services Company	235	4,943	4	5,182
18	ATE Investment, Inc.	2,954	1,042	8	4,004
19	Atlantic Generation, Inc.	180	2,567	4	2,751
20	Conectiv Services II, Inc.	41	1,473	13	1,527
21	Conectiv Solutions LLC	313	18	1	332
22	Atlantic Jersey Thermal Systems, Inc.		1		1
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	133,726,301	361,296,681	596,744	495,619,726

Potomac Electric Power Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)

131,722,878 Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan			59,654,546		11.5	-	-	686,027,279	-	-	-	57,168,940	-	
Feb			269,388		10.5	-	-	2,828,574	-	-	-	235,715	-	
Mar			394,160		9.5	-	-	3,744,520	-	-	-	312,043	-	
Apr			(138,303)		8.5	-	-	(1,175,576)	-	-	-	(97,965)	-	
May			18,927		7.5	-	-	141,953	-	-	-	11,829	-	
Jun	110,212,247		15,719		6.5	716,379,606	-	102,174	-	59,698,300	-	8,514	-	
Jul			17,178		5.5	-	-	94,479	-	-	-	7,873	-	
Aug			13,879		4.5	-	-	62,456	-	-	-	5,205	-	
Sep			13,620		3.5	-	-	47,670	-	-	-	3,973	-	
Oct			13,837		2.5	-	-	34,593	-	-	-	2,883	-	
Nov			13,880		1.5	-	-	20,820	-	-	-	1,735	-	
Dec	-		13,697		0.5	-	-	6,849	-	-	-	571	-	
Total	110,212,247	-	60,300,528	-		716,379,606	-	-	-	59,698,300	-	57,661,316	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										59,698,300	-	57,661,316	-	
								Input to Line 21 of Appendix A		59,698,300	-		-	59,698,300
								Input to Line 43a of Appendix A				57,661,316		57,661,316
								Month In Service or Month for CWIP		5.50	#DIV/0!	0.53	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 59,698,300 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

145,917,650 — Must run Appendix A to get this number (with inputs on lines 21 and 43a of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)

$ 145,917,650

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

139,185,369 Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2
For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 187,270,631 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
	Monthly Additions Other Plant In Service	Monthly Additions Other Plant In Service	Monthly Additions MAPP CWIP	Monthly Additions MAPP In Service	Weighting	Other Plant In Service Amount (A x E)	Other Plant In Service Amount (B x E)	MAPP CWIP Amount (C x E)	MAPP In Service Amount (D x E)	Other Plant In Service (F / 12)	Other Plant In Service (G / 12)	MAPP CWIP (H / 12)	MAPP In Service (I / 12)	
Jan	$31,401,470		59,654,547		11.5	361,116,907	-	686,027,291	-	30,093,076	-	57,168,941	-	
Feb	$227,145		269,388		10.5	2,385,022	-	2,828,574	-	198,752	-	235,715	-	
Mar	$20,465,003		394,159		9.5	194,417,530	-	3,744,511	-	16,201,461	-	312,043	-	
Apr	$11,330,223		542,156		8.5	96,306,895	-	4,608,326	-	8,025,575	-	384,027	-	
May	$13,101,587		-10,996,122		7.5	98,261,901	-	(82,470,911)	-	8,188,492	-	(6,872,576)	-	
Jun	$70,620,127		58,815		6.5	459,030,826	-	382,298	-	38,252,569	-	31,858	-	
Jul	($257,838)		5,309		5.5	(1,418,110)	-	29,200	-	(118,176)	-	2,433	-	
Aug	$36,407,610		1,651		4.5	163,834,243	-	7,430	-	13,652,854	-	619	-	
Sep	$262,634		-5,347		3.5	919,219	-	(18,715)	-	76,602	-	(1,560)	-	
Oct	$558,896		-2,721,506		2.5	1,397,240	-	(6,803,765)	-	116,437	-	(566,980)	-	
Nov	$2,876,696		0		1.5	4,315,045	-	-	-	359,587	-	-	-	
Dec	$277,078		0		0.5	138,539	-	-	-	11,545	-	-	-	
Total	187,270,631	-	47,203,050	-		1,380,705,256	-	-	-	115,058,771	-	50,694,520	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										115,058,771	-	50,694,520	-	
								Input to Line 21 of Appendix A		115,058,771	-		-	115,058,771
								Input to Line 43a of Appendix A				50,694,520		50,694,520
								Month In Service or Month for CWIP		4.63	#DIV/0!	(0.89)	#DIV/0!	

137,890,030 Result of Formula for Reconciliation Must run Appendix A with cap adds in line 21 & line 20
(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
	Monthly Additions Other Plant In Service	Monthly Additions Other Plant In Service	Monthly Additions MAPP CWIP	Monthly Additions MAPP In Service	Weighting	Other Plant In Service Amount (A x E)	Other Plant In Service Amount (B x E)	MAPP CWIP Amount (C x E)	MAPP In Service Amount (D x E)	Other Plant In Service (F / 12)	Other Plant In Service (G / 12)	MAPP CWIP (H / 12)	MAPP In Service (I / 12)	
Jan			47,203,050		11.5	-	-	542,835,080	-	-	-	45,236,257	-	
Feb			-		10.5	-	-	-	-	-	-	-	-	
Mar			(47,203,050)		9.5	-	-	(448,428,979)	-	-	-	(37,369,082)	-	
Apr	8,096,839		-		8.5	68,823,132	-	-	-	5,735,261	-	-	-	
May			-		7.5	-	-	-	-	-	-	-	-	
Jun	36,103,548		-		6.5	234,673,062	-	-	-	19,556,089	-	-	-	
Jul			-		5.5	-	-	-	-	-	-	-	-	
Aug			-		4.5	-	-	-	-	-	-	-	-	
Sep	2,800,000		-		3.5	9,800,000	-	-	-	816,667	-	-	-	
Oct			-		2.5	-	-	-	-	-	-	-	-	
Nov	8,669,220		-		1.5	13,003,830	-	-	-	1,083,653	-	-	-	
Dec	-		-		0.5	-	-	-	-	-	-	-	-	
Total	55,669,607	-	-	-		326,300,024	-	-	-	27,191,669	-	7,867,175	-	
New Transmission Plant Additions and CWIP (weighted by months in service)								0		27,191,669	-	7,867,175	-	
155,391,116								Input to Line 21 of Appendix A		27,191,669	-		-	27,191,669
								Input to Line 43a of Appendix A				7,867,175		7,867,175
								Month In Service or Month for CWIP		6.14	#DIV/0!	#DIV/0!	#DIV/0!	

9 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 7		The forecast in Prior Year		
137,890,030	-	136,955,012	=	935,019

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March 0.2800%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	77,918	0.2800%	11.5	2,509	80,427
Jul	Year 1	77,918	0.2800%	10.5	2,291	80,209
Aug	Year 1	77,918	0.2800%	9.5	2,073	79,991
Sep	Year 1	77,918	0.2800%	8.5	1,854	79,773
Oct	Year 1	77,918	0.2800%	7.5	1,636	79,555
Nov	Year 1	77,918	0.2800%	6.5	1,418	79,336
Dec	Year 1	77,918	0.2800%	5.5	1,200	79,118
Jan	Year 2	77,918	0.2800%	4.5	982	78,900
Feb	Year 2	77,918	0.2800%	3.5	764	78,682
Mar	Year 2	77,918	0.2800%	2.5	545	78,464
Apr	Year 2	77,918	0.2800%	1.5	327	78,245
May	Year 2	77,918	0.2800%	0.5	109	78,027
Total		935,019				950,727

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	950,727	0.2800%	80,677	872,712
Jul	Year 2	872,712	0.2800%	80,677	794,479
Aug	Year 2	794,479	0.2800%	80,677	716,027
Sep	Year 2	716,027	0.2800%	80,677	637,356
Oct	Year 2	637,356	0.2800%	80,677	558,464
Nov	Year 2	558,464	0.2800%	80,677	479,351
Dec	Year 2	479,351	0.2800%	80,677	400,016
Jan	Year 3	400,016	0.2800%	80,677	320,460
Feb	Year 3	320,460	0.2800%	80,677	240,681
Mar	Year 3	240,681	0.2800%	80,677	160,678
Apr	Year 3	160,678	0.2800%	80,677	80,451
May	Year 3	80,451	0.2800%	80,677	-
Total with interest				968,119	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	968,119
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 155,391,116
Revenue Requirement for Year 3	156,359,235

10 May Year 3 Post results of Step 9 on PJM web site

$ 156,359,235 Post results of Step 3 on PJM web site

11 June Year 3 Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 156,359,235

Potomac Electric Power Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	18.5356%
5	B	167	Net Plant Carrying Charge per 100 Basis Point in ROE without Deprec	19.2821%
6	C		Line B less Line A	0.7465%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income T	7.4117%

9 **The FCR resulting from Formula in a given year is used for that year only.**
10 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**
11 **Per FERC order in Docket No. ER08-10, the ROE is 11.30%, which includes a 50 basis point RTO membership adder as authorized by FERC to become effecitve on D**

Line		Details		B0512 MAPP CWIP	B0512 MAPP Abandoned Plant
12	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes
13	Useful life of project	Life		35	5
14	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 18, Otherwise "No"	CIAC	(Yes or No)	No	No
15	Input the allowed ROE Incentive	Increased ROE (Basis Points)		150	-50
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		18.5356%	18.5356%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		19.6553%	18.1623%
18	Columns A, B or C from Attachment 6	Investment		47,203,050	46,963,980
19	Line 18 divided by line 13	Annual Depreciation/ Amortization Exp		1,348,659	9,392,796
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		1.00	3.00

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Amortization	Ending	Revenue
31	Base FCR	2013	47,203,050	-	-	1,458,227	46,963,980	7,827,330	39,136,650	13,872,503
32	W Increased ROE	2013	47,203,050	-	-	1,546,320	46,963,980	7,827,330	39,136,650	13,750,771
33	Base FCR	2014				-	39,136,650	9,392,796	29,743,854	14,905,993
34	W Increased ROE	2014				-	39,136,650	9,392,796	29,743,854	14,794,974
35	Base FCR	2015				-	29,743,854	9,392,796	20,351,058	13,164,984
36	W Increased ROE	2015				-	29,743,854	9,392,796	20,351,058	13,089,023
37	Base FCR	2016				-	20,351,058	9,392,796	10,958,262	11,423,974
38	W Increased ROE	2016				-	20,351,058	9,392,796	10,958,262	11,383,072
39	Base FCR	2017				-	10,958,262	9,392,796	1,565,466	9,682,964
40	W Increased ROE	2017				-	10,958,262	9,392,796	1,565,466	9,677,121
41	Base FCR	2018				-	1,565,466	1,565,466	0	1,565,466
42	W Increased ROE	2018				-	1,565,466	1,565,466	0	1,565,466
43	Base FCR	2019				-				
44	W Increased ROE	2019				-				
45	Base FCR	2020				-				
46	W Increased ROE	2020				-				
47	Base FCR	2021				-				
48	W Increased ROE	2021				-				
49	Base FCR	2022				-				
50	W Increased ROE	2022				-				
51	Base FCR	2023				-				
52	W Increased ROE	2023				-				
53	Base FCR	2024				-				
54	W Increased ROE	2024				-				
55	Base FCR	2025				-				
56	W Increased ROE	2025				-				
57	Base FCR	2026				-				
58	W Increased ROE	2026				-				
59	Base FCR	2027				-				
60	W Increased ROE	2027				-				
61		....		....	.....	....		....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....

63

Note 1: line 15 for the abandoned MAPP plant will be -50 to remove the 50 basis point adder included in the return on Line 122 of Attachment H-9A. Line 18 is sourced from ecember 1, 2007. Per FERC orders in Dockets No. ER08-686 and ER08-1423 the ROE for specific projects identified or to be indentified in Attachment 7 is 12.80%, which includes a 150 basis-point tranmission incentive ROE adder as authorized by FERC to be

B0288 Brighton Sub	B0251 Bells Mill 230kV Capacitors	B0252 Northern System Rel -3 230 Caps	BO319 Burches Hill 500/230 kV transformer - second 1000 MVA
Yes	Yes	Yes	No
35	35	35	35
No	No	No	No
150	0	0	150
18.5356%	18.5356%	18.5356%	18.5356%
19.6553%	18.5356%	18.5356%	19.6553%
33,558,380	6,986,903	5,013,166	36,700,000
958,811	199,626	143,233	1,048,571
6.50	5.50	5.50	8.00

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
30,242,492	958,811	29,283,682	6,386,713	6,479,521	199,626	6,279,895	1,363,641	4,649,115	143,233	4,505,881	978,425	35,301,905	1,048,571	34,253,333	7,397,627
30,242,492	958,811	29,283,682	6,714,617	6,479,521	199,626	6,279,895	1,363,641	4,649,115	143,233	4,505,881	978,425	35,301,905	1,048,571	34,253,333	7,781,179
29,283,682	958,811	28,324,871	6,208,991	6,279,895	199,626	6,080,269	1,326,639	4,505,881	143,233	4,362,648	951,876	34,253,333	1,048,571	33,204,762	7,203,268
29,283,682	958,811	28,324,871	6,526,159	6,279,895	199,626	6,080,269	1,326,639	4,505,881	143,233	4,362,648	951,876	34,253,333	1,048,571	33,204,762	7,575,079
28,324,871	958,811	27,366,060	6,031,270	6,080,269	199,626	5,880,643	1,289,637	4,362,648	143,233	4,219,415	925,327	33,204,762	1,048,571	32,156,190	7,008,910
28,324,871	958,811	27,366,060	6,337,702	6,080,269	199,626	5,880,643	1,289,637	4,362,648	143,233	4,219,415	925,327	33,204,762	1,048,571	32,156,190	7,368,978
27,366,060	958,811	26,407,249	5,853,549	5,880,643	199,626	5,681,018	1,252,636	4,219,415	143,233	4,076,181	898,777	32,156,190	1,048,571	31,107,619	6,814,551
27,366,060	958,811	26,407,249	6,149,244	5,880,643	199,626	5,681,018	1,252,636	4,219,415	143,233	4,076,181	898,777	32,156,190	1,048,571	31,107,619	7,162,878
26,407,249	958,811	25,448,438	5,675,828	5,681,018	199,626	5,481,392	1,215,634	4,076,181	143,233	3,932,948	872,228	31,107,619	1,048,571	30,059,048	6,620,192
26,407,249	958,811	25,448,438	5,960,787	5,681,018	199,626	5,481,392	1,215,634	4,076,181	143,233	3,932,948	872,228	31,107,619	1,048,571	30,059,048	6,956,778
25,448,438	958,811	24,489,627	5,498,107	5,481,392	199,626	5,281,766	1,178,632	3,932,948	143,233	3,789,715	845,679	30,059,048	1,048,571	29,010,476	6,425,833
25,448,438	958,811	24,489,627	5,772,329	5,481,392	199,626	5,281,766	1,178,632	3,932,948	143,233	3,789,715	845,679	30,059,048	1,048,571	29,010,476	6,750,678
24,489,627	958,811	23,530,816	5,320,385	5,281,766	199,626	5,082,140	1,141,630	3,789,715	143,233	3,646,481	819,130	29,010,476	1,048,571	27,961,905	6,231,474
24,489,627	958,811	23,530,816	5,583,872	5,281,766	199,626	5,082,140	1,141,630	3,789,715	143,233	3,646,481	819,130	29,010,476	1,048,571	27,961,905	6,544,577
23,530,816	958,811	22,572,006	5,142,664	5,082,140	199,626	4,882,514	1,104,628	3,646,481	143,233	3,503,248	792,581	27,961,905	1,048,571	26,913,333	6,037,115
23,530,816	958,811	22,572,006	5,395,414	5,082,140	199,626	4,882,514	1,104,628	3,646,481	143,233	3,503,248	792,581	27,961,905	1,048,571	26,913,333	6,338,477
22,572,006	958,811	21,613,195	4,964,943	4,882,514	199,626	4,682,889	1,067,627	3,503,248	143,233	3,360,015	766,032	26,913,333	1,048,571	25,864,762	5,842,756
22,572,006	958,811	21,613,195	5,206,957	4,882,514	199,626	4,682,889	1,067,627	3,503,248	143,233	3,360,015	766,032	26,913,333	1,048,571	25,864,762	6,132,377
21,613,195	958,811	20,654,384	4,787,222	4,682,889	199,626	4,483,263	1,030,625	3,360,015	143,233	3,216,782	739,483	25,864,762	1,048,571	24,816,190	5,648,398
21,613,195	958,811	20,654,384	5,018,499	4,682,889	199,626	4,483,263	1,030,625	3,360,015	143,233	3,216,782	739,483	25,864,762	1,048,571	24,816,190	5,926,277
20,654,384	958,811	19,695,573	4,609,501	4,483,263	199,626	4,283,637	993,623	3,216,782	143,233	3,073,548	712,933	24,816,190	1,048,571	23,767,619	5,454,039
20,654,384	958,811	19,695,573	4,830,042	4,483,263	199,626	4,283,637	993,623	3,216,782	143,233	3,073,548	712,933	24,816,190	1,048,571	23,767,619	5,720,177
19,695,573	958,811	18,736,762	4,431,779	4,283,637	199,626	4,084,011	956,621	3,073,548	143,233	2,930,315	686,384	23,767,619	1,048,571	22,719,048	5,259,680
19,695,573	958,811	18,736,762	4,641,584	4,283,637	199,626	4,084,011	956,621	3,073,548	143,233	2,930,315	686,384	23,767,619	1,048,571	22,719,048	5,514,076
18,736,762	958,811	17,777,951	4,254,058	4,084,011	199,626	3,884,385	919,619	2,930,315	143,233	2,787,082	659,835	22,719,048	1,048,571	21,670,476	5,065,321
18,736,762	958,811	17,777,951	4,453,127	4,084,011	199,626	3,884,385	919,619	2,930,315	143,233	2,787,082	659,835	22,719,048	1,048,571	21,670,476	5,307,976
17,777,951	958,811	16,819,140	4,076,337	3,884,385	199,626	3,684,760	882,618	2,787,082	143,233	2,643,848	633,286	21,670,476	1,048,571	20,621,905	4,870,962
17,777,951	958,811	16,819,140	4,264,669	3,884,385	199,626	3,684,760	882,618	2,787,082	143,233	2,643,848	633,286	21,670,476	1,048,571	20,621,905	5,101,876
16,819,140	958,811	15,860,330	3,898,616	3,684,760	199,626	3,485,134	845,616	2,643,848	143,233	2,500,615	606,737	20,621,905	1,048,571	19,573,333	4,676,603
16,819,140	958,811	15,860,330	4,076,212	3,684,760	199,626	3,485,134	845,616	2,643,848	143,233	2,500,615	606,737	20,621,905	1,048,571	19,573,333	4,895,776
....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

Line C on Attachment 5 - Cost Support.

come effective June 1, 2008 and November 1, 2008 respectively. Per FERC order in Docket No. ER13-607 the ROE for the MAPP abandoned plant is 10.8% effective March 1, 2013.

BO367.1/BO367.2 Reconductor Dickerson-Quince Orchard 230 kV	BO512.7 Chalk Point 230 kV Breaker 1A	BO512.8 Chalk Point 230 kV Breaker 1B	BO512.9 Chalk Point 230 kV Breaker 2A
Yes	Yes	Yes	Yes
35	35	35	35
No	No	No	No
150	0	0	0
18.5356%	18.5356%	18.5356%	18.5356%
19.6553%	18.5356%	18.5356%	18.5356%
20,000,000	2,000,000	2,000,000	2,000,000
571,429	57,143	57,143	57,143
8.00	8.00	8.00	8.00

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
19,238,095	571,429	18,666,667	4,031,405	1,923,810	57,143	1,866,667	403,140	1,923,810	57,143	1,866,667	403,140	1,923,810	57,143	1,866,667	403,140
19,238,095	571,429	18,666,667	4,240,424	1,923,810	57,143	1,866,667	403,140	1,923,810	57,143	1,866,667	403,140	1,923,810	57,143	1,866,667	403,140
18,666,667	571,429	18,095,238	3,925,487	1,866,667	57,143	1,809,524	392,549	1,866,667	57,143	1,809,524	392,549	1,866,667	57,143	1,809,524	392,549
18,666,667	571,429	18,095,238	4,128,108	1,866,667	57,143	1,809,524	392,549	1,866,667	57,143	1,809,524	392,549	1,866,667	57,143	1,809,524	392,549
18,095,238	571,429	17,523,810	3,819,569	1,809,524	57,143	1,752,381	381,957	1,809,524	57,143	1,752,381	381,957	1,809,524	57,143	1,752,381	381,957
18,095,238	571,429	17,523,810	4,015,792	1,809,524	57,143	1,752,381	381,957	1,809,524	57,143	1,752,381	381,957	1,809,524	57,143	1,752,381	381,957
17,523,810	571,429	16,952,381	3,713,652	1,752,381	57,143	1,695,238	371,365	1,752,381	57,143	1,695,238	371,365	1,752,381	57,143	1,695,238	371,365
17,523,810	571,429	16,952,381	3,903,476	1,752,381	57,143	1,695,238	371,365	1,752,381	57,143	1,695,238	371,365	1,752,381	57,143	1,695,238	371,365
16,952,381	571,429	16,380,952	3,607,734	1,695,238	57,143	1,638,095	360,773	1,695,238	57,143	1,638,095	360,773	1,695,238	57,143	1,638,095	360,773
16,952,381	571,429	16,380,952	3,791,160	1,695,238	57,143	1,638,095	360,773	1,695,238	57,143	1,638,095	360,773	1,695,238	57,143	1,638,095	360,773
16,380,952	571,429	15,809,524	3,501,816	1,638,095	57,143	1,580,952	350,182	1,638,095	57,143	1,580,952	350,182	1,638,095	57,143	1,580,952	350,182
16,380,952	571,429	15,809,524	3,678,843	1,638,095	57,143	1,580,952	350,182	1,638,095	57,143	1,580,952	350,182	1,638,095	57,143	1,580,952	350,182
15,809,524	571,429	15,238,095	3,395,899	1,580,952	57,143	1,523,810	339,590	1,580,952	57,143	1,523,810	339,590	1,580,952	57,143	1,523,810	339,590
15,809,524	571,429	15,238,095	3,566,527	1,580,952	57,143	1,523,810	339,590	1,580,952	57,143	1,523,810	339,590	1,580,952	57,143	1,523,810	339,590
15,238,095	571,429	14,666,667	3,289,981	1,523,810	57,143	1,466,667	328,998	1,523,810	57,143	1,466,667	328,998	1,523,810	57,143	1,466,667	328,998
15,238,095	571,429	14,666,667	3,454,211	1,523,810	57,143	1,466,667	328,998	1,523,810	57,143	1,466,667	328,998	1,523,810	57,143	1,466,667	328,998
14,666,667	571,429	14,095,238	3,184,063	1,466,667	57,143	1,409,524	318,406	1,466,667	57,143	1,409,524	318,406	1,466,667	57,143	1,409,524	318,406
14,666,667	571,429	14,095,238	3,341,895	1,466,667	57,143	1,409,524	318,406	1,466,667	57,143	1,409,524	318,406	1,466,667	57,143	1,409,524	318,406
14,095,238	571,429	13,523,810	3,078,146	1,409,524	57,143	1,352,381	307,815	1,409,524	57,143	1,352,381	307,815	1,409,524	57,143	1,352,381	307,815
14,095,238	571,429	13,523,810	3,229,579	1,409,524	57,143	1,352,381	307,815	1,409,524	57,143	1,352,381	307,815	1,409,524	57,143	1,352,381	307,815
13,523,810	571,429	12,952,381	2,972,228	1,352,381	57,143	1,295,238	297,223	1,352,381	57,143	1,295,238	297,223	1,352,381	57,143	1,295,238	297,223
13,523,810	571,429	12,952,381	3,117,262	1,352,381	57,143	1,295,238	297,223	1,352,381	57,143	1,295,238	297,223	1,352,381	57,143	1,295,238	297,223
12,952,381	571,429	12,380,952	2,866,311	1,295,238	57,143	1,238,095	286,631	1,295,238	57,143	1,238,095	286,631	1,295,238	57,143	1,238,095	286,631
12,952,381	571,429	12,380,952	3,004,946	1,295,238	57,143	1,238,095	286,631	1,295,238	57,143	1,238,095	286,631	1,295,238	57,143	1,238,095	286,631
12,380,952	571,429	11,809,524	2,760,393	1,238,095	57,143	1,180,952	276,039	1,238,095	57,143	1,180,952	276,039	1,238,095	57,143	1,180,952	276,039
12,380,952	571,429	11,809,524	2,892,630	1,238,095	57,143	1,180,952	276,039	1,238,095	57,143	1,180,952	276,039	1,238,095	57,143	1,180,952	276,039
11,809,524	571,429	11,238,095	2,654,475	1,180,952	57,143	1,123,810	265,448	1,180,952	57,143	1,123,810	265,448	1,180,952	57,143	1,123,810	265,448
11,809,524	571,429	11,238,095	2,780,314	1,180,952	57,143	1,123,810	265,448	1,180,952	57,143	1,123,810	265,448	1,180,952	57,143	1,123,810	265,448
11,238,095	571,429	10,666,667	2,548,558	1,123,810	57,143	1,066,667	254,856	1,123,810	57,143	1,066,667	254,856	1,123,810	57,143	1,066,667	254,856
11,238,095	571,429	10,666,667	2,667,998	1,123,810	57,143	1,066,667	254,856	1,123,810	57,143	1,066,667	254,856	1,123,810	57,143	1,066,667	254,856
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B0512.12 Chalk Point 230 kV Breaker 3A	BO478 Burches Hill-Palmer Cr Upgrade 23090, 91, 92, 93	BO499 Burches Hill Sub: Add 3rd 500/230kV	BO526 Ritchie-Benning: Install (2) 230kV Lines
Yes	Yes	Yes	Yes
35	35	35	35
No	No	No	No
0	150	150	0
18.5356%	18.5356%	18.5356%	18.5356%
18.5356%	19.6553%	19.6553%	18.5356%
2,000,000	15,875,382	29,544,357	58,581,170
57,143	453,582	844,124	1,673,748
12.00	6.00	6.00	6.00

B0512.12 Chalk Point 230 kV Breaker 3A

Beginning	Depreciation	Ending	Revenue
1,942,857	57,143	1,885,714	406,671
1,942,857	57,143	1,885,714	406,671
1,885,714	57,143	1,828,571	396,079
1,885,714	57,143	1,828,571	396,079
1,828,571	57,143	1,771,429	385,488
1,828,571	57,143	1,771,429	385,488
1,771,429	57,143	1,714,286	374,896
1,771,429	57,143	1,714,286	374,896
1,714,286	57,143	1,657,143	364,304
1,714,286	57,143	1,657,143	364,304
1,657,143	57,143	1,600,000	353,712
1,657,143	57,143	1,600,000	353,712
1,600,000	57,143	1,542,857	343,120
1,600,000	57,143	1,542,857	343,120
1,542,857	57,143	1,485,714	332,529
1,542,857	57,143	1,485,714	332,529
1,485,714	57,143	1,428,571	321,937
1,485,714	57,143	1,428,571	321,937
1,428,571	57,143	1,371,429	311,345
1,428,571	57,143	1,371,429	311,345
1,371,429	57,143	1,314,286	300,753
1,371,429	57,143	1,314,286	300,753
1,314,286	57,143	1,257,143	290,162
1,314,286	57,143	1,257,143	290,162
1,257,143	57,143	1,200,000	279,570
1,257,143	57,143	1,200,000	279,570
1,200,000	57,143	1,142,857	268,978
1,200,000	57,143	1,142,857	268,978
1,142,857	57,143	1,085,714	258,386
1,142,857	57,143	1,085,714	258,386
....	....	.....	....
....	.....	.....	....

BO478 Burches Hill-Palmer Cr Upgrade 23090, 91, 92, 93

Beginning	Depreciation	Ending	Revenue
15,648,591	453,582	15,195,008	3,270,066
15,648,591	453,582	15,195,008	3,440,212
15,195,008	453,582	14,741,426	3,185,992
15,195,008	453,582	14,741,426	3,351,059
14,741,426	453,582	14,287,844	3,101,918
14,741,426	453,582	14,287,844	3,261,906
14,287,844	453,582	13,834,261	3,017,844
14,287,844	453,582	13,834,261	3,172,753
13,834,261	453,582	13,380,679	2,933,770
13,834,261	453,582	13,380,679	3,083,600
13,380,679	453,582	12,927,097	2,849,695
13,380,679	453,582	12,927,097	2,994,447
12,927,097	453,582	12,473,514	2,765,621
12,927,097	453,582	12,473,514	2,905,293
12,473,514	453,582	12,019,932	2,681,547
12,473,514	453,582	12,019,932	2,816,140
12,019,932	453,582	11,566,350	2,597,473
12,019,932	453,582	11,566,350	2,726,987
11,566,350	453,582	11,112,767	2,513,399
11,566,350	453,582	11,112,767	2,637,834
11,112,767	453,582	10,659,185	2,429,325
11,112,767	453,582	10,659,185	2,548,681
10,659,185	453,582	10,205,603	2,345,251
10,659,185	453,582	10,205,603	2,459,528
10,205,603	453,582	9,752,020	2,261,176
10,205,603	453,582	9,752,020	2,370,375
9,752,020	453,582	9,298,438	2,177,102
9,752,020	453,582	9,298,438	2,281,221
9,298,438	453,582	8,844,856	2,093,028
9,298,438	453,582	8,844,856	2,192,068
....	....	.....	....
....	.....	.....	....

BO499 Burches Hill Sub: Add 3rd 500/230kV

Beginning	Depreciation	Ending	Revenue
29,122,295	844,124	28,278,170	6,085,649
29,122,295	844,124	28,278,170	6,402,294
28,278,170	844,124	27,434,046	5,929,185
28,278,170	844,124	27,434,046	6,236,378
27,434,046	844,124	26,589,921	5,772,722
27,434,046	844,124	26,589,921	6,070,463
26,589,921	844,124	25,745,797	5,616,259
26,589,921	844,124	25,745,797	5,904,547
25,745,797	844,124	24,901,672	5,459,795
25,745,797	844,124	24,901,672	5,738,632
24,901,672	844,124	24,057,548	5,303,332
24,901,672	844,124	24,057,548	5,572,716
24,057,548	844,124	23,213,423	5,146,868
24,057,548	844,124	23,213,423	5,406,801
23,213,423	844,124	22,369,299	4,990,405
23,213,423	844,124	22,369,299	5,240,885
22,369,299	844,124	21,525,174	4,833,942
22,369,299	844,124	21,525,174	5,074,970
21,525,174	844,124	20,681,050	4,677,478
21,525,174	844,124	20,681,050	4,909,054
20,681,050	844,124	19,836,925	4,521,015
20,681,050	844,124	19,836,925	4,743,139
19,836,925	844,124	18,992,801	4,364,551
19,836,925	844,124	18,992,801	4,577,223
18,992,801	844,124	18,148,676	4,208,088
18,992,801	844,124	18,148,676	4,411,308
18,148,676	844,124	17,304,552	4,051,624
18,148,676	844,124	17,304,552	4,245,392
17,304,552	844,124	16,460,427	3,895,161
17,304,552	844,124	16,460,427	4,079,477
....	....	.....	....
....	.....	.....	....

BO526 Ritchie-Benning: Install (2) 230kV Lines

Beginning	Depreciation	Ending	Revenue
57,744,296	1,673,748	56,070,548	12,066,752
57,744,296	1,673,748	56,070,548	12,066,752
56,070,548	1,673,748	54,396,801	11,756,513
56,070,548	1,673,748	54,396,801	11,756,513
54,396,801	1,673,748	52,723,053	11,446,274
54,396,801	1,673,748	52,723,053	11,446,274
52,723,053	1,673,748	51,049,305	11,136,035
52,723,053	1,673,748	51,049,305	11,136,035
51,049,305	1,673,748	49,375,558	10,825,796
51,049,305	1,673,748	49,375,558	10,825,796
49,375,558	1,673,748	47,701,810	10,515,557
49,375,558	1,673,748	47,701,810	10,515,557
47,701,810	1,673,748	46,028,062	10,205,318
47,701,810	1,673,748	46,028,062	10,205,318
46,028,062	1,673,748	44,354,314	9,895,080
46,028,062	1,673,748	44,354,314	9,895,080
44,354,314	1,673,748	42,680,567	9,584,841
44,354,314	1,673,748	42,680,567	9,584,841
42,680,567	1,673,748	41,006,819	9,274,602
42,680,567	1,673,748	41,006,819	9,274,602
41,006,819	1,673,748	39,333,071	8,964,363
41,006,819	1,673,748	39,333,071	8,964,363
39,333,071	1,673,748	37,659,324	8,654,124
39,333,071	1,673,748	37,659,324	8,654,124
37,659,324	1,673,748	35,985,576	8,343,885
37,659,324	1,673,748	35,985,576	8,343,885
35,985,576	1,673,748	34,311,828	8,033,646
35,985,576	1,673,748	34,311,828	8,033,646
34,311,828	1,673,748	32,638,080	7,723,407
34,311,828	1,673,748	32,638,080	7,723,407
....	....	.....	....
....	.....	.....	....

BO701.1 Benning Sub: Add 3rd 230/69kV, 250MVA	BO496 Brighton Sub: Upgrade T1 500/230kv Transormer
Yes	Yes
35	35
No	No
0	150
18.5356%	18.5356%
18.5356%	19.6553%
5,226,954	18,731,954
149,342	535,199
6.00	6.00

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
5,152,283	149,342	5,002,942	1,076,666	18,731,954	267,599	18,464,355	2,264,044	$ 61,867,809		$ 61,867,809
5,152,283	149,342	5,002,942	1,076,666	18,731,954	267,599	18,464,355	2,384,651	$ 63,362,044	$ 63,362,044	
5,002,942	149,342	4,853,600	1,048,985	18,464,355	535,199	17,929,156	3,858,473	$ 61,875,128		$ 61,875,128
5,002,942	149,342	4,853,600	1,048,985	18,464,355	535,199	17,929,156	4,059,234	$ 63,328,730	$ 63,328,730	
4,853,600	149,342	4,704,259	1,021,303	17,929,156	535,199	17,393,957	3,759,270	$ 58,872,543		$ 58,872,543
4,853,600	149,342	4,704,259	1,021,303	17,929,156	535,199	17,393,957	3,954,039	$ 60,311,803	$ 60,311,803	
4,704,259	149,342	4,554,917	993,622	17,393,957	535,199	16,858,759	3,660,068	$ 55,869,958		$ 55,869,958
4,704,259	149,342	4,554,917	993,622	17,393,957	535,199	16,858,759	3,848,844	$ 57,294,876	$ 57,294,876	
4,554,917	149,342	4,405,576	965,941	16,858,759	535,199	16,323,560	3,560,866	$ 52,867,372		$ 52,867,372
4,554,917	149,342	4,405,576	965,941	16,858,759	535,199	16,323,560	3,743,649	$ 54,277,949	$ 54,277,949	
4,405,576	149,342	4,256,234	938,259	16,323,560	535,199	15,788,361	3,461,664	$ 43,488,298		$ 43,488,298
4,405,576	149,342	4,256,234	938,259	16,323,560	535,199	15,788,361	3,638,454	$ 44,855,318	$ 44,855,318	
4,256,234	149,342	4,106,892	910,578	15,788,361	535,199	15,253,163	3,362,462	$ 40,661,257		$ 40,661,257
4,256,234	149,342	4,106,892	910,578	15,788,361	535,199	15,253,163	3,533,259	$ 41,978,876	$ 41,978,876	
4,106,892	149,342	3,957,551	882,897	15,253,163	535,199	14,717,964	3,263,259	$ 39,399,681		$ 39,399,681
4,106,892	149,342	3,957,551	882,897	15,253,163	535,199	14,717,964	3,428,064	$ 40,667,900	$ 40,667,900	
3,957,551	149,342	3,808,209	855,215	14,717,964	535,199	14,182,765	3,164,057	$ 38,138,105		$ 38,138,105
3,957,551	149,342	3,808,209	855,215	14,717,964	535,199	14,182,765	3,322,869	$ 39,356,924	$ 39,356,924	
3,808,209	149,342	3,658,868	827,534	14,182,765	535,199	13,647,566	3,064,855	$ 36,876,529		$ 36,876,529
3,808,209	149,342	3,658,868	827,534	14,182,765	535,199	13,647,566	3,217,674	$ 38,045,948	$ 38,045,948	
3,658,868	149,342	3,509,526	799,853	13,647,566	535,199	13,112,368	2,965,653	$ 35,614,954		$ 35,614,954
3,658,868	149,342	3,509,526	799,853	13,647,566	535,199	13,112,368	3,112,479	$ 36,734,973	$ 36,734,973	
3,509,526	149,342	3,360,185	772,171	13,112,368	535,199	12,577,169	2,866,451	$ 34,353,378		$ 34,353,378
3,509,526	149,342	3,360,185	772,171	13,112,368	535,199	12,577,169	3,007,283	$ 35,423,997	$ 35,423,997	
3,360,185	149,342	3,210,843	744,490	12,577,169	535,199	12,041,970	2,767,248	$ 33,091,802		$ 33,091,802
3,360,185	149,342	3,210,843	744,490	12,577,169	535,199	12,041,970	2,902,088	$ 34,113,021	$ 34,113,021	
3,210,843	149,342	3,061,502	716,809	12,041,970	535,199	11,506,772	2,668,046	$ 31,830,226		$ 31,830,226
3,210,843	149,342	3,061,502	716,809	12,041,970	535,199	11,506,772	2,796,893	$ 32,802,045	$ 32,802,045	
3,061,502	149,342	2,912,160	689,127	11,506,772	535,199	10,971,573	2,568,844	$ 30,568,651		$ 30,568,651
3,061,502	149,342	2,912,160	689,127	11,506,772	535,199	10,971,573	2,691,698	$ 31,491,069	$ 31,491,069	
....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....		$ -	
									$ 795,101,798	$ 771,500,846

Potomac Electric Power Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
112	**Less LTD on Securitization Bonds**	0

Calculation of the above Securitization Adjustments

Attachment 4E - PPL Formula Update

ATTACHMENT H-8G

PPL Electric Utilities Corporation

Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	2012 Data
Shaded cells are input cells				
Allocators				
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	12,018,709
2	Total Wages Expense		p354.28.b	102,136,227
3	Less A&G Wages Expense		p354.27.b	2,120,568
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	100,015,659
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**12.0168%**
	Plant Allocation Factors			
6	Electric Plant in Service		p207.104.g	6,501,887,796
7	Accumulated Depreciation (Total Electric Plant)	(Note J)	p219.29.c	2,299,248,949
8	Accumulated Amortization	(Note A)	p200.21.c	45,309,117
9	Total Accumulated Depreciation		(Line 7 + 8)	2,344,558,066
10	Net Plant		(Line 6 - Line 9)	4,157,329,730
11	Transmission Gross Plant (excluding Land Held for Future Use)		(Line 25 - Line 24)	1,762,395,436
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**27.1059%**
13	Transmission Net Plant (excluding Land Held for Future Use)		(Line 33 - Line 24)	1,215,227,381
14	**Net Plant Allocator**		(Line 13 / Line 10)	**29.2310%**
Plant Calculations				
	Plant In Service			
15	Transmission Plant In Service	(Note B)	p207.58.g	1,538,083,941
16	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year	For Reconciliation Only	Attachment 6	
17	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)	(Note B)	Attachment 6	137,326,964
18	**Total Transmission Plant**		(Line 15 - Line 16 + Line 17)	**1,675,410,905**
19	General		p207.99.g	621,752,703
20	Intangible		p205.5.g	102,103,345
21	Total General and Intangible Plant		(Line 19 + Line 20)	723,856,048
22	Wage & Salary Allocator		(Line 5)	12.0168%
23	**Total General and Intangible Functionalized to Transmission**		(Line 21 * Line 22)	**86,984,531**
24	**Land Held for Future Use**	(Note C) (Note P)	Attachment 5	**37,556,123**
25	**Total Plant In Rate Base**		**(Line 18 + Line 23 + Line 24)**	**1,799,951,559**
	Accumulated Depreciation			
26	Transmission Accumulated Depreciation	(Note J)	p219.25.c	**516,522,634**
27	Accumulated General Depreciation	(Note J)	p219.28.c	209,711,782
28	Accumulated Amortization		(Line 8)	45,309,117
29	Total Accumulated Depreciation		(Line 27 + 28)	255,020,899
30	Wage & Salary Allocator		(Line 5)	12.0168%
31	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 29 * Line 30)	30,645,421
32	**Total Accumulated Depreciation**		**(Sum Lines 26 + 31)**	**547,168,055**
33	**Total Net Property, Plant & Equipment**		**(Line 25 - Line 32)**	**1,252,783,504**

Adjustment To Rate Base				
	Accumulated Deferred Income Taxes			
34	**ADIT net of FASB 106 and 109**		Attachment 1	**-158,362,203**
	CWIP for Incentive Transmission Projects			
35	CWIP Balances for Current Rate Year	(Note H)	Attachment 6	**205,873,856**
	Prepayments			
36	Prepayments	(Note A) (Note O)	Attachment 5	**3,603,011**
	Materials and Supplies			
37	Undistributed Stores Expense	(Note A)	p227.16.c	2,837,814
38	Wage & Salary Allocator		(Line 5)	12.0168%
39	Total Undistributed Stores Expense Allocated to Transmission		(Line 37 * Line 38)	341,015
40	Transmission Materials & Supplies		p227.8.c	9,788,704
41	**Total Materials & Supplies Allocated to Transmission**		(Line 39 + Line 40)	**10,129,719**
	Cash Working Capital			
42	Operation & Maintenance Expense		(Line 70)	74,276,800
43	1/8th Rule		1/8	12.5%
44	**Total Cash Working Capital Allocated to Transmission**		(Line 42 * Line 43)	**9,284,600**
45	**Total Adjustment to Rate Base**		(Lines 34 + 35 + 36 + 41 + 44)	**70,528,983**
46	**Rate Base**		(Line 33 + Line 45)	**1,323,312,487**
Operations & Maintenance Expense				
	Transmission O&M			
47	Transmission O&M		Attachment 5	109,037,021
48	Less Account 565		Attachment 5	58,090,727
49	Plus Charges billed to Transmission Owner and booked to Account 565	(Note N)	Attachment 5	0
50	**Transmission O&M**		(Lines 47 - 48 + 49)	**50,946,294**
	Allocated Administrative & General Expenses			
51	Total A&G		323.197b	179,033,604
52	Less: Administrative & General Expenses on Securitization Bonds	(Note O)	Attachment 8	0
53	Plus: Fixed PBOP expense	(Note J)	Attachment 5	10,028,618
54	Less: Actual PBOP expense		Attachment 5	3,489,356
55	Less Property Insurance Account 924		p323.185.b	9,161,310
56	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	4,547,826
57	Less General Advertising Exp Account 930.1		p323.191.b	0
58	Less EPRI Dues	(Note D)	p352 & 353	0
59	Administrative & General Expenses		Sum (Lines 51 + 53) - Line 52 - Sum (Lines 54 to 58)	171,863,730
60	Wage & Salary Allocator		(Line 5)	12.0168%
61	**Administrative & General Expenses Allocated to Transmission**		(Line 59 * Line 60)	**20,652,568**
	Directly Assigned A&G			
62	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	0
63	General Advertising Exp Account 930.1	(Note K)	Attachment 5	0
64	**Subtotal - Accounts 928 and 930.1 - Transmission Related**		(Line 62 + Line 63)	**0**
65	Property Insurance Account 924	(Note G)	Attachment 5	9,161,310
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 924 and 930.1 - General		(Line 65 + Line 66)	9,161,310
68	Net Plant Allocator		(Line 14)	29.2310%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**2,677,939**
70	**Total Transmission O&M**		**(Lines 50 + 61 + 64 + 69)**	**74,276,800**

	Depreciation & Amortization Expense				
	Depreciation Expense				
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J)	Attachment 5	**25,579,790**
72	General Depreciation Expense Including Amortization of Limited Term Plant		(Note J)	Attachment 5	16,453,564
73	Intangible Amortization		(Note A)	p336.1.d&e	17,130,177
74	Total			(Line 72 + Line 73)	33,583,741
75	Wage & Salary Allocator			(Line 5)	12.0168%
76	**General Depreciation & Intangible Amortization Allocated to Transmission**			(Line 74 * Line 75)	**4,035,700**
77	**Total Transmission Depreciation & Amortization**			**(Lines 71 + 76)**	**29,615,490**
	Taxes Other than Income Taxes				
78	**Taxes Other than Income Taxes**			Attachment 2	**2,412,582**
79	**Total Taxes Other than Income Taxes**			**(Line 78)**	**2,412,582**
	Return \ Capitalization Calculations				
	Long Term Interest				
80	Long Term Interest			p117.62.c through 66.c	100,374,814
81	Less LTD Interest on Securitization Bonds		(Note O)	Attachment 8	0
82	**Long Term Interest**			(Line 80 - Line 81)	**100,374,814**
83	**Preferred Dividends**		enter positive	p118.29.c	**3,906,250**
	Common Stock				
84	Proprietary Capital			p112.16.c	2,060,370,224
85	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	101,914
86	Less Preferred Stock			(Line 94)	0
87	Less Account 216.1			p112.12.c	5,266,418
88	**Common Stock**			(Line 84 - 85 - 86 - 87)	**2,055,001,892**
	Capitalization				
89	Long Term Debt			p112.18.c, 19.c & 21.c	1,974,040,000
90	Less Loss on Reacquired Debt			p111.81.c	65,452,319
91	Plus Gain on Reacquired Debt			p113.61.c	0
92	Less LTD on Securitization Bonds		(Note O)	Attachment 8	0
93	Total Long Term Debt			(Line 89 - 90 + 91 - 92)	1,908,587,681
94	Preferred Stock			p112.3.c	0
95	Common Stock			(Line 88)	2,055,001,892
96	**Total Capitalization**			(Sum Lines 93 to 95)	**3,963,589,573**
97	Debt %	Total Long Term Debt		(Line 93 / Line 96)	48.2%
98	Preferred %	Preferred Stock		(Line 94 / Line 96)	0.0%
99	Common %	Common Stock		(Line 95 / Line 96)	51.8%
100	Debt Cost	Total Long Term Debt		(Line 82 / Line 93)	0.0526
101	Preferred Cost	Preferred Stock		(Line 83 / Line 94)	0.0000
102	Common Cost	Common Stock	(Note J)	Fixed	0.1168
103	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 97 * Line 100)	0.0253
104	Weighted Cost of Preferred	Preferred Stock		(Line 98 * Line 101)	0.0000
105	Weighted Cost of Common	Common Stock		(Line 99 * Line 102)	0.0606
106	**Rate of Return on Rate Base (ROR)**			(Sum Lines 103 to 105)	**0.0859**
107	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 106)**	**113,648,067**

Composite Income Taxes

	Income Tax Rates			
108	FIT=Federal Income Tax Rate	(Note I)		35.00%
109	SIT=State Income Tax Rate or Composite			9.99%
110	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code	0.00%
111	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		41.49%
112	T / (1-T)			70.92%
	ITC Adjustment			
113	Amortized Investment Tax Credit - Transmission Related		Attachment 5	-456,347
114	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)	Line 113 * (1 / (1 - Line 111))	**-779,994**
115	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =	[Line 112 * Line 107 * (1- (Line 103 / Line 106))]	**56,833,546**
116	**Total Income Taxes**		**(Line 114 + Line 115)**	**56,053,552**

Revenue Requirement

	Summary			
117	Net Property, Plant & Equipment		(Line 33)	1,252,783,504
118	Total Adjustment to Rate Base		(Line 45)	70,528,983
119	Rate Base		(Line 46)	1,323,312,487
120	Total Transmission O&M		(Line 70)	74,276,800
121	Total Transmission Depreciation & Amortization		(Line 77)	29,615,490
122	Taxes Other than Income		(Line 79)	2,412,582
123	Investment Return		(Line 107)	113,648,067
124	Income Taxes		(Line 116)	56,053,552
125	**Gross Revenue Requirement**		**(Sum Lines 120 to 124)**	**276,006,492**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
126	Transmission Plant In Service		(Line 15)	1,538,083,941
127	Excluded Transmission Facilities	(Note M)	Attachment 5	0
128	Included Transmission Facilities		(Line 126 - Line 127)	1,538,083,941
129	Inclusion Ratio		(Line 128 / Line 126)	100.00%
130	Gross Revenue Requirement		(Line 125)	276,006,492
131	**Adjusted Gross Revenue Requirement**		(Line 129 * Line 130)	**276,006,492**
	Revenue Credits			
132	**Revenue Credits**		Attachment 3	**23,470,990**
133	**Net Revenue Requirement**		**(Line 131 - Line 132)**	**252,535,502**
	Net Plant Carrying Charge			
134	Gross Revenue Requirement		(Line 130)	**276,006,492**
135	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**1,364,762,127**
136	Net Plant Carrying Charge		(Line 134 / Line 135)	**20.2238%**
137	Net Plant Carrying Charge without Depreciation		(Line 134 - Line 71) / Line 135	**18.3495%**
138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 134 - Line 71 - Line 107 - Line 116) / Line 135	**5.9150%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
139	Gross Revenue Requirement Less Return and Taxes		(Line 130 - Line 123 - Line 124)	**106,304,872**
140	Increased Return and Taxes		Attachment 4	**181,428,482**
141	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 139 + Line 140)	**287,733,354**
142	Net Transmission Plant		(Line 18 - Line 26 + Line 35)	**1,364,762,127**
143	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 141 / Line 142)	**21.0830%**
144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 141 - Line 71) / Line 142	**19.2087%**
145	**Net Revenue Requirement**		(Line 133)	**252,535,502**
146	True-up amount		Attachment 6	**9,301,736**
147	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**-**
148	**Net Zonal Revenue Requirement**		(Line 145 + 146 + 147)	**261,837,237**
	Network Zonal Service Rate			
149	1 CP Peak	(Note L)	PJM Data	**7,381.5**
150	Rate ($/MW-Year)		(Line 148 / 149)	**$ 35,472**
151	**Network Service Rate ($/MW/Year)**		**(Line 150)**	**$ 35,472**

Notes

A Electric portion only.

B Line 16, for the Reconciliation, includes New Transmission Plant that actually was placed in service weighted by the number of months it actually was in service. Line 17 includes New Transmission Plant to be placed in service in the current calendar year.

C Includes Transmission portion only.

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 page 351.h. Property Insurance excludes prior period adjustment in the first year of the formula's operation and reconciliation for the first year.

H CWIP can be included only 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.
The calculation of the Reconciliation revenue requirement according to Step 7 of Attachment 6 ("Estimate and Reconciliation Worksheet") shall reflect the actual tax rates in effect for the Rate Year being reconciled ("Test Year"). When statutory marginal tax rates change during such Test Year, the effective tax rate used in the formula shall be weighted by the number of days each such rate was in effect. For example, a 35% rate in effect for 120 days superseded by a 40% rate in effect for the remainder of the year will be calculated as: ((.3500 x 120) + (.4000 x 245))/365 = .3836.

J ROE will be as follows: (i.) 11.60% for the period November 1, 2008 through May 31, 2009; (ii.) 11.64% for the period June 1, 2009 through May 31, 2010; (iii.) 11.68% on June 1, 2010 through May 31, 2011 and thereafter. No change in ROE will be made absent a filing at FERC.
PBOP expense is fixed until changed as the result of a filing at FERC.
Depreciation rates shown in Attachment 9 are fixed until changed as the result of a filing at FERC.
Upon request, PPL Electric Utilities Corporation will provide workpapers at the annual update to reconcile formula depreciation expense and depreciation accruals to Form No. 1 amounts.
As set forth in Attachment 5, added to the depreciation expense will be actual removal costs (net of salvage) amortized over five years.

K Education and outreach expenses related to transmission (e.g., 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 Includes only charges incurred for system integration, such as those under the EHV Agreement, and transmission costs paid to others that benefit transmission customers.

O Amounts associated with transition bonds issued to securitize the recovery of retail stranded costs are removed from account balances, pursuant to an Order entered by the Pennsylvania Public Utility Commission on May 21, 1999 at Docket No. R-00994637, in accordance with Pennsylvania's Electric Generation Customer Choice and Competition Act.

P Any gain from the sale of land included in Land Held for Future Use in the Formula Rate received during the Rate Year shall be used to reduce the ATRR in the Rate Year. The Formula Rate shall not include any losses on sales of such land.

PPL Electric Utilities Corporation

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Transmission Related	*Plant Related*	*Labor Related*	*Total Transmission ADIT*	
ADIT- 282	(170,131,030)	0	(56,132,374)		From Acct. 282 total, below
ADIT-283	0	(27,158,458)	(597,274)		From Acct. 283 total, below
ADIT-190	25,962,746	0	4,675,631		From Acct. 190 total, below
Subtotal	(144,168,284)	(27,158,458)	(52,054,017)		Sum lines 1 through 3
Wages & Salary Allocator			12.0168%		
Net Plant Allocator		29.2310%			
ADIT	(144,168,284)	(7,938,678)	(6,255,241)	(158,362,203)	Sum Cols. D, E, F; Enter as negative Appendix A, line 42.
	row 4	row 5 * row 4	row 5 * row 4		

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A	B	C	D	E	F	G
ADIT-190	***Total***	***Gas, Prod, Dist Or Other Related***	***Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Account 190						
Accumulated Deferred Investment Tax Credits (Non-Transmission)	1,121,571	1,121,571				Basis difference between book plant and tax plant basis related to investment tax credits on distribution property.
Accumulated Deferred Investment Tax Credits (Transmission)	279,486		279,486			Basis difference between book plant and tax plant basis related to investment tax credits on transmission property.
Regulatory Liability - Income Taxes Related to ITC (Non-Tx)	795,434	795,434				Liability recorded for regulatory purposes related to accumulated deferred investment tax credit book/tax basis difference on distribution property.
Regulatory Liability - Income Taxes Related to ITC (Tx)	198,212		198,212			Liability recorded for regulatory purposes related to accumulated deferred investment tax credit book/tax basis difference on transmission property.
Contributions in Aid of Construction (Non-Tx)	82,606,713	82,606,713				Distribution related income that is taxable for tax return purposes, but recorded as a reduction to plant for book purposes.
Contributions in Aid of Construction (Tx-related)	23,402,880		23,402,880			Transmission related income that is taxable for tax return purposes, but recorded as a reduction to plant for book purposes.
Pensions and Post-Retirement	7,633,590	7,633,590				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes.
FAS158 Regulatory Liability	150,244,890	150,244,890				Liability recorded for regulatory purposes for FAS 158 pension and post-retirement costs.
Bad Debts	13,038,832	13,038,832				Retail related book expense not deductible for tax return purposes.
Vacation Pay	4,502,873				4,502,873	Book expense not deductible for tax return purposes - labor related to all functions.
Deferred Compensation	172,758				172,758	Book expense not deductible for tax return purposes - labor related to all functions.
Taxes Other Than Income Taxes	6,171,719	6,171,719				Book expense not deductible for tax return purposes - retail related gross receipts and sales & use taxes.
RAR Adjustments	2,200,285	2,200,285				Distribution related IRS audit adjustments.
Obsolete Inventory	68,927	68,927				Distribution related book expense not deductible for tax return purposes.
Environmental Liability	2,700,925	2,700,925				Distribution related book expense for manufactured gas plants not deductible for tax return purposes.
Post Employment Liabilities	3,511,734	3,511,734				Book expense not deductible for tax return purposes.
State NOL Carryforwards	39,508,009	39,508,009				State net operating loss carryforward.
STAS Adjustment	0	0				Distribution related expense deferred for book purposes and deducted for tax purposes.
Tax Credit Carryforward	101,186	101,186				Tax credits carryforward to a future period.
Conservation Program Regulatory Asset	3,121,905	3,121,905				Distribution related expense deferred for book purposes and deducted for tax purposes.
Universal Service Rider over/undercollection	6,914,805	6,914,805				Distribution related expense deferred for book purposes and deducted for tax purposes.
Generation Service Charge over/undercollection	10,941,987	10,941,987				Distribution related expense deferred for book purposes and deducted for tax purposes.
Transmission Formula Rate over/undercollection	19,249		19,249			Transmission related expense deferred for book purposes and deducted for tax purposes.
Transmission Service Charge over/undercollection	2,687,121	2,687,121				Distribution related expense deferred for book purposes and deducted for tax purposes.
Book Contingencies	1,358,912	1,358,912				Distribution related book expense not deductible for tax return purposes.
Federal NOL Carryforward	83,972,204	81,431,587	2,540,617			Federal net operating loss carryforward.
Deferred Intercompany Transactions	(221,917)	(221,917)				Retail related income recorded for book purposes not includable in taxable income - related to receivables factoring.
Smart Meter Technology Regulatory Liability	1,069,092	1,069,092				Distribution related expense deferred for book purposes and deducted for tax purposes.
Charitable Contribution Carryforward	888,323	888,323				Distribution related tax deduction carryforward to a future period.
Subtotal - p234	449,011,705	417,895,630	26,440,444	0	4,675,631	
Less FASB 109 Above if not separately removed	2,394,690	1,916,992	477,698			
Less FASB 106 Above if not separately removed	6,291,857	6,291,857				
Total	440,325,158	409,686,781	25,962,746	0	4,675,631	

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.

PPL Electric Utilities Corporation

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod, Dist Or Other Related*	*Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Account 282						
ACRS/MACRS Property (Non-Transmission)	(549,152,786)	(549,152,786)				Deductions for distribution related tax depreciation in excess of book depreciation at federal rate.
ACRS/MACRS Property (General Plant)	(52,545,641)				(52,545,641)	Deductions for general plant related tax depreciation in excess of book depreciation at applicable federal and state rates.
ACRS/MACRS Property (Transmission)	(153,707,087)		(153,707,087)			Deductions for transmission related method/life, book and tax recovery differences on pre-ACRS/MACRS property, ACRS/MACRS property and unamortized net negative salvage at federal and state rates.
FAS109 regulatory assets/liabilities related to plant	(174,578,388)	(174,578,388)				Asset recorded for regulatory purposes to adjust plant related deferred taxes to current federal and state rates.
Basis adjustments between book and tax plant (Non-Tx)	(297,442,975)	(297,442,975)				Basis difference between Distribution related book plant and tax plant basis at federal & state rates.
Basis adjustments between book and tax plant (General Plant)	3,386,366				3,386,366	Basis difference between book plant and tax plant basis at federal & state rates.
Basis adjustments between book and tax plant (Tx-related)	(17,541,852)		(17,541,852)			Basis difference between Transmission related plant and tax plant basis at federal & state rates.
RAR adjustments related to plant (Non-Transmission)	13,274,015	13,274,015				Settled IRS audit adjustments related to Distribution plant.
RAR adjustments related to plant (Transmission)	1,117,909		1,117,909			Settled IRS audit adjustments related to Transmission plant.
RAR adjustments related to plant (General Plant)	(6,973,099)				(6,973,099)	Settled IRS audit adjustments related to General plant.
Effectively Settled Audit Adjustments	(9,864,376)	(9,864,376)				Agreed to IRS audit adjustments related to Distribution plant.
Non-Utility Property	(115,387)	(115,387)				Difference between net book plant and net tax plant resulting from deductions for non-utility related tax depreciation in excess of book depreciation and cost basis differences between book plant and tax plant at federal and state tax rates.
Subtotal - p275	(1,244,143,301)	(1,017,879,897)	(170,131,030)	0	(56,132,374)	
Less FASB 109 Above if not separately removed	(173,170,143)	(173,170,143)				
Less FASB 106 Above if not separately removed	0					
Total	(1,070,973,158)	(844,709,754)	(170,131,030)	0	(56,132,374)	

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.

PPL Electric Utilities Corporation

A	B	C	D	E	F	G
ADIT-283	*Total*	*Gas, Prod, Dist Or Other Related*	*Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Account 283						
Reacquired debt costs	(27,158,458)			(27,158,458)		Plant related expense deferred for book purposes and deducted for tax purposes.
FAS 109 regulatory assets/liabilities	(123,813,061)	(123,813,061)				Asset recorded for regulatory purposes related to book and tax basis plant and non-plant differences.
Pension and post-retirement	(70,387,872)	(70,387,872)				Expense and equity(FAS158) adjustments for book purposes not deductible for tax purposes.
FAS158 Regulatory Asset	(150,244,891)	(150,244,891)				Asset recorded for regulatory purposes for FAS 158 pension and post-retirement costs.
Storms Deferrals	(24,085,054)	(24,085,054)				Distribution related expense deferred for book purposes and deducted for tax purposes.
RAR Adjustments	(3,022,456)	(3,022,456)				Distribution related IRS audit adjustments.
Clearing accounts	(597,274)				(597,274)	Expense deferred for book purposes and deducted for tax purposes.
Receivables Factoring	(4,492,107)	(4,492,107)				Retail related income recorded for book purposes not includable in taxable income.
Prepaid Insurance	(917,427)	(917,427)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Competitive Enhancement Rider over/undercollections	(337,666)	(337,666)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Unrealized gains/losses	(72,278)	(72,278)				Equity adjustment for book purposes not includable in taxable income.
Rate case expenses	112,890	112,890				Retail related expense deferred for book purposes and deducted for tax purposes.
Default Service Plan Regulatory Asset	(668,455)	(668,455)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Conservation Program Regulatory Asset	(321,454)	(321,454)				Distribution related expense deferred for book purposes and deducted for tax purposes.
Deferred intercompany gain - trademark sale	(514,252)	(514,252)				Income recorded for book purposes not includable in taxable income.
Subtotal - p277	(406,519,815)	(378,764,083)	0	(27,158,458)	(597,274)	
Less FASB 109 Above if not separately removed	(122,814,312)	(122,814,312)				
Less FASB 106 Above if not separately removed	0	0				
Total	(283,705,503)	(255,949,771)	0	(27,158,458)	(597,274)	

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.

PPL Electric Utilities Corporation

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	**Page 263 Col (i)**	**Allocator**	**Allocated Amount**
	Plant Related		**Net Plant Allocator**	
1	Real Property (State, Municipal or Local)	2,117,661		
2	PURTA	1,732,828		
3				
4				
5				
6				
7				
8	**Total Plant Related**	3,850,489	29.2310%	1,125,535
	Labor Related		**Wages & Salary Allocator**	
9	Federal FICA	7,269,060		
10	Federal Unemployment	48,138		
11	State Unemployment	320,105		
12				
13				
14	**Total Labor Related**	7,637,303	12.0168%	917,762
	Other Included		**Net Plant Allocator**	
15	PA Capital Stock Tax	1,262,466		
16	Tax on Insurance Premiums	872		
17		0		
18				
19	**Total Other Included**	1,263,338	29.2310%	369,286
20	**Total Included (Lines 8 + 14 + 19)**	12,751,130		2,412,582
	Currently Excluded			
21	Gross Receipts	100,160,594		
22	Sales and Use	(834,566)		
23				
24				
25				
26				
27				
28	**Subtotal, Excluded**	99,326,028		
29	**Total, Included and Excluded (Line 20 + Line 28)**	112,077,158		
30	**Total Other Taxes from p114.14.c less Tax on Securitization Bonds**	112,077,158		
31	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.

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, which 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 described in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

PPL Electric Utilities Corporation

Attachment 3 - Revenue Credit Worksheet

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related		1,624,535
	Account 456 - Other Electric Revenues (Note 1)		
2	Transmission for Others (Note 3)		-
3	Schedule 12 Revenues (Note 3)		13,244,683
4	Schedule 1A		2,596,511
5	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (Note 3)		-
6	Point-to-Point Service revenues for which the load is not included in the divisor received by Transmission Owner (e.g. Schedule 8)		3,013,376
7	Professional Services provided to others		1,192,933
8	Facilities Charges including Interconnection Agreements (Note 2)		1,798,952
9	Gross Revenue Credits	(Sum Lines 1-10)	23,470,990
10	Amount offset from Note 3 below		-

11 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 150 of Appendix A.

12 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.

13 Note 3: 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, e.g., revenues associated with distribution facilities. In addition, Revenues from Schedule 12 are not included in the total above to the extent they are credited directly by PJM to zonal customers.

PPL Electric Utilities Corporation

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 29 + Line 39 from below	181,428,482
B	100 Basis Point increase in ROE			1.00%
Return Calculation				
			Appendix A Line or Source Reference	
1	**Rate Base**		(Attachment A Line 46)	1,323,312,487
	Long Term Interest			
2	Long Term Interest		(Attachment A Line 80)	100,374,814
3	Less LTD Interest on Securitization Bonds		Attachment 8	-
4	Long Term Interest		(Line 2 - Line 3)	100,374,814
5	**Preferred Dividends**	enter positive	p118.29.c	3,906,250
	Common Stock			
6	Proprietary Capital		p112.16.c	2,060,370,224
7	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	101,914
8	Less Preferred Stock		(Attachment A Line 86)	0
9	Less Account 216.1		p112.12.c	5,266,418
10	Common Stock		(Line 6 - 7 - 8 - 9)	2,055,001,892
	Capitalization			
11	Long Term Debt		p112.18.c, 19.c & 21.c	1,974,040,000
12	Less Loss on Reacquired Debt		p111.81.c	65,452,319
13	Plus Gain on Reacquired Debt		p113.61.c	0
14	Less LTD on Securitization Bonds		Attachment 8	0
15	Total Long Term Debt		(Line 11 - 12 + 13 - 14)	1,908,587,681
16	Preferred Stock		p112.3.c	0
17	Common Stock		(Line 10)	2,055,001,892
18	Total Capitalization		(Sum Lines 15 to 17)	3,963,589,573
19	Debt %	Total Long Term Debt	(Line 15 / Line 18)	48.2%
20	Preferred %	Preferred Stock	(Line 16 / Line 18)	0.0%
21	Common %	Common Stock	(Line 17 / Line 18)	51.8%
22	Debt Cost	Total Long Term Debt	(Line 4 / Line 15)	0.0526
23	Preferred Cost	Preferred Stock	(Line 5 / Line 16)	0.0000
24	Common Cost	Common Stock	Fixed	0.1268
25	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 19 * Line 22)	0.0253
26	Weighted Cost of Preferred	Preferred Stock	(Line 20 * Line 23)	0.0000
27	Weighted Cost of Common	Common Stock	(Line 21 * Line 24)	0.0657
28	**Rate of Return on Rate Base (ROR)**		(Sum Lines 25 to 27)	**0.0911**
29	**Investment Return = Rate Base * Rate of Return**		**(Line 1 * Line 28)**	**120,509,044**
Composite Income Taxes				
	Income Tax Rates			
30	FIT=Federal Income Tax Rate			35.00%
31	SIT=State Income Tax Rate or Composite			9.99%
32	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
33	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		41.49%
34	CIT = T / (1-T)			70.92%
35	1 / (1-T)			170.92%
	ITC Adjustment			
36	Amortized Investment Tax Credit		Attachment 5	(456,347)
37	**ITC Adjust. Allocated to Trans. - Grossed Up**		(Line 36 * (1 / (1 - Line 33)	**-779,994**
38	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		61,699,432
39	**Total Income Taxes**			**60,919,438**

Attachment 5 - Cost Support

ITC Adjustment

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Form No. 1 Amount	Transmission Related	Non-transmission Related	Details
113	**Amortized Investment Tax Credit**	Company Records	-1,372,174	-456,347	-915,827	Enter Negative

Transmission / Non-transmission Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Transmission Related Major Items	Transmission Related Minor Items	Non-transmission Related	Details
24	**Land Held for Future Use**	(Note C)	p.214.d - p214.6.d &	40,353,116	33,052,194	4,503,929	2,796,993	
			Company Records		0	0		Removal of land held for future use (if any) that is included in CWIP balance
		(Note P)	Company Records		0	0		Gains from the sale of Land Held for Future Use
					33,052,194	4,503,929		Balance for Appendix A

Adjustments to A & G Expense

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Total	Prior Period Adjustment	Adjusted Total	Details
	Allocated Administrative & General Expenses					
53	Fixed PBOP expense	FERC Authorized	10,028,618			
54	Actual PBOP expense	Company Records	3,489,356			Current year actual PBOP expense
65	Property Insurance Account 924	p323.185.b	9,161,310	0	9,161,310	Annual Premium associated with storm insurance excluding recoveries related to prior periods. (See FM 1 note to page 320 line 185)

Regulatory Expense Related to Transmission Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G						
62	Regulatory Commission Exp Account 928	(Note G)	p350-151h	4,547,826	0	4,547,826	

Safety Related Advertising Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
66	General Advertising Exp Account 930.1	(Note F)	p323.191.b	-	-	-	

MultiState Workpaper

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates							
			PA					
109	SIT=State Income Tax Rate or Composite	(Note I)	9.99%					

Education and Out Reach Cost Support

	Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
63	General Advertising Exp Account 930.1	(Note K)	p323.191.b	-		-	-

PPL Electric Utilities Corporation

Attachment 5 - Cost Support

Excluded Plant Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
127	Excluded Transmission Facilities		(Note M)		**General Description of the Facilities**
	Instructions:			**Enter $**	
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			**0**	**None**
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 workpaper	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

Prepayments and Prepaid Pension Asset

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Prepayments on Securitization Bonds Adjustment	POLR and Retail Related Adjustment	Prepayments	W&S Allocator	Functionalized to TX	Description of the Prepayments
36 Prepayments									
Prepayments	(Note A) (Note O)	Form 1 -- p111.57.c	75,766,213	0	45,783,166	29,983,047	12.0168%	3,603,011	Less amounts related to POLR, Retail Issues and Bond Securitization.

Adjustments to Transmission O&M

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Total	Adjustments	Transmission Related	Details
47	Transmission O&M	p.321.112.b	109,796,998	759,977	109,037,021	Adjustment for Ancillary Services p321.88b and p321.92b.
48	Less Account 565	p.321.96.b	58,090,727	0	58,090,727	**None**

Facility Credits under Section 30.9 of the PJM OATT

Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & PJM Documentation
	Net Revenue Requirement		
147	Facility Credits under Section 30.9 of the PJM OATT	-	**None**

PJM Load Cost Support

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
149	1 CP Peak	(Note L)	PJM Data	**7,381.5**	

Depreciation Expense

Appendix A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Total	Actual Cost of Removal, Net of Salvage Costs Year 1 2007	Year 2 2008	Year 3 2009	Year 4 2010	Year 5 2011	Total	5 - Year Amortization
71	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	23,352,144							
	Transmission Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	2,227,646	2,107,526	1,433,010	2,342,429	1,932,132	3,323,131	11,138,228	2,227,646
	Total Transmission Depreciation Expense Including Amortization of Limited Term I	(Note J)	Company Records	25,579,790							
72	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	17,655,676							
	General Plant Cost of Removal, Net of Salvage	(Note J)	Company Records	-1,202,112	-1,066,425	-937,714	-2,236,807	-1,205,818	-563,798	-6,010,562	-1,202,112
	Total General Depreciation Expense Including Amortization of Limited Term Plant	(Note J)	Company Records	16,453,564							

PPL Electric Utilities Corporation

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2007)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2008)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2008 - May 31, 2009)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2008)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2009)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2009 - May 31, 2010)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form No. 1 data for Year 1 (e.g., 2007)

$ 168,736,252 Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 16, 17 or 35 of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2008)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Copperstone Substation (b0468)	(C) Monthly Additions Susq-Rose CWIP < 500kV (b0487.1)	(D) Monthly Additions Susq-Rose PIS < 500kV (b0487.1)	(E) Monthly Additions Susq-Rose CWIP >= 500kV (b0487)	(F) Monthly Additions Susq-Rose PIS >= 500kV (b0487)	(G) Weighting	(H) Other Plant In Service Amount (A x G)	(I) Copperstone Substation Amount (B x G) (b0468)	(J) Susq-Rose CWIP Amount (C x G) < 500kV (b0487.1)	(K) Susq-Rose PIS Amount (D x G) < 500kV (b0487.1)	(L) Susq-Rose CWIP Amount (E x G) >= 500kV (b0487)	(M) Susq-Rose PIS Amount (F x G) >= 500kV (b0487)	(N) Other Plant In Service (H / 12)
CWIP Balance Dec (prior yr.)			275,991		41,321,203		12			3,311,898		495,854,435		
Jan	11,748,716	1,422,145	1,853	-	508,491	3,967	11.5	135,110,235	16,354,667	21,308	-	5,847,647	45,621	11,259,186
Feb	12,093,739	292,282	5,698	-	812,466	6,428	10.5	126,984,260	3,068,960	59,826	-	8,530,898	67,494	10,582,022
Mar	7,236,124	241,634	2,501	-	781,282	2,595	9.5	68,743,182	2,295,519	23,756	-	7,422,178	24,653	5,728,598
Apr	17,632,890	2,058,863	7,952	-	797,310	952	8.5	149,879,565	17,500,336	67,592	-	6,777,135	8,092	12,489,964
May	6,895,152	17,285,181	9,779	-	1,022,606	-	7.5	51,713,640	129,638,858	73,343	-	7,669,546	-	4,309,470
Jun	7,409,179		11,558	-	5,288,562	-	6.5	48,159,664	-	75,124	-	34,375,650	-	4,013,305
Jul	3,933,575		12,107	-	1,914,202	-	5.5	21,634,663	-	66,586	-	10,528,112	-	1,802,889
Aug	4,059,236		13,316	-	2,560,042	-	4.5	18,266,562	-	59,921	-	11,520,191	-	1,522,214
Sep	7,295,742		48,867	-	5,608,854	-	3.5	25,535,097	-	171,034	-	19,630,988	-	2,127,925
Oct	4,629,244		57,481	-	(5,588,780)	16,000,000	2.5	11,573,110	-	143,703	-	(13,971,951)	40,000,000	964,426
Nov	34,337,062		79,559	-	11,357,555	-	1.5	51,505,593	-	119,339	-	17,036,333	-	4,292,133
Dec	39,782,267		76,227	-	8,596,570	-	0.5	19,891,134	-	38,114	-	4,298,285	-	1,657,594
Total	157,052,927	21,300,104	602,888	-	74,980,363	16,013,942		728,996,704	168,858,339	4,231,544	-	615,519,447	40,145,859	60,749,725

New Transmission Plant Additions and CWIP (weighted by months in service)

Input to Line 17 of Appendix A	60,749,725
Input to Line 35 of Appendix A	
Month In Service or Month for CWIP	7.36

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 185,872,821 — Must run Appendix A to get this number (with inputs on lines 17 and 35 of Attachment A)

4 May Year 2 Post results of Step 3 on PJM web site

$ 185,872,821 — Must run Appendix A to get this number (with inputs on lines 17 and 35 of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2008 - May 31, 2009)

$ 185,872,821

6 April Year 3 TO populates the formula with Year 2 data from FERC Form No. 1 for Year 2 (e.g., 2008)

$ 168,736,252 Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 16, 17 or 35 of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2
For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 — $ 199,782,855 Input to Formula Line 16

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Copperstone Substation (b0468)	(C) Monthly Additions Susq-Rose CWIP < 500kV (b0487.1)	(D) Monthly Additions Susq-Rose PIS < 500kV (b0487.1)	(E) Monthly Additions Susq-Rose CWIP >= 500kV (b0487)	(F) Monthly Additions Susq-Rose PIS >= 500kV (b0487)	(G) Weighting
CWIP Balance Dec (prior yr.)			275,991		41,321,203		12
Jan	11,748,717	1,422,145	1,853	-	508,491	3,967	11.5
Feb	12,073,543	292,282	5,698	-	812,466	6,428	10.5
Mar	7,236,124	241,634	2,501	-	781,282	2,595	9.5
Apr	17,632,890	2,058,863	7,952	-	797,310	952	8.5
May	8,454,384	16,057,335	12,812	-	1,130,249	1,857	7.5
Jun	5,507,463	93,124	-2,947	-	1,146,132	1,470	6.5
Jul	6,520,518	28,405	24,686	-	1,588,552	1,465	5.5
Aug	10,343,910	395,676	136,162	-	3,786,132	1,314	4.5
Sep	12,548,746	134,971	21,974	-	4,305,047	92	3.5
Oct	22,175,942	(1,782)	-147,367	-	(8,048,472)	16,951,360	2.5
Nov	27,629,123	(295,081)	121,092	-	13,060,745	67,232	1.5
Dec	18,794,709	49,463	303,125	219,588	17,060,370	1,381,433	0.5
Total	160,666,069	20,477,034	763,531	219,588	78,249,508	18,420,165	

	(H) Other Plant In Service Amount (A x G)	(I) Copperstone Substation Amount (B x G) (b0468)	(J) Susq-Rose CWIP Amount (C x G) < 500kV (b0487.1)	(K) Susq-Rose PIS Amount (D x G) < 500kV (b0487.1)	(L) Susq-Rose CWIP Amount (E x G) >= 500kV (b0487)	(M) Susq-Rose PIS Amount (F x G) >= 500kV (b0487)	(N) Other Plant In Service (H / 12)
CWIP Balance Dec (prior yr.)			3,311,898		495,854,435		
Jan	135,110,240	16,354,667	21,308	-	5,847,647	45,621	11,259,187
Feb	126,772,205	3,068,960	59,826	-	8,530,898	67,494	10,564,350
Mar	68,743,180	2,295,519	23,756	-	7,422,178	24,653	5,728,598
Apr	149,879,564	17,500,335	67,594	-	6,777,135	8,092	12,489,964
May	63,407,880	120,430,013	96,089	-	8,476,866	13,928	5,283,990
Jun	35,798,511	605,304	(19,153)	-	7,449,861	9,555	2,983,209
Jul	35,862,847	156,227	135,770	-	8,737,037	8,058	2,988,571
Aug	46,547,594	1,780,544	612,729	-	17,037,596	5,913	3,878,966
Sep	43,920,612	472,397	76,909	-	15,067,664	322	3,660,051
Oct	55,439,855	(4,455)	(368,418)	-	(20,121,181)	42,378,400	4,619,988
Nov	41,443,685	(442,622)	181,637	-	19,591,118	100,848	3,453,640
Dec	9,397,354	24,731	151,563	109,794	8,530,185	690,717	783,113
Total	812,323,527	162,241,621	4,351,509	109,794	589,201,441	43,353,599	67,693,627

New Transmission Plant Additions and CWIP (weighted by months in service)

Input to Line 17 of Appendix A 67,693,627
Input to Line 35 of Appendix A
Month In Service or Month for CWIP 6.94

$ 199,221,933 Result of Formula for Reconciliation — Must run Appendix A to get this number (with inputs in lines 16, 17 and 35 of Appendix A)
(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 8		The forecast in Prior Year		
194,856,528	-	185,872,821	=	8,983,707

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of the Current Yr 0.2800%

Month	Yr	1/12 of Step 8 (See Note #1)	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	748,642	0.2800%	11.5	24,106	772,749
Jul	Year 1	748,642	0.2800%	10.5	22,010	770,652
Aug	Year 1	748,642	0.2800%	9.5	19,914	768,556
Sep	Year 1	748,642	0.2800%	8.5	17,818	766,460
Oct	Year 1	748,642	0.2800%	7.5	15,721	764,364
Nov	Year 1	748,642	0.2800%	6.5	13,625	762,268
Dec	Year 1	748,642	0.2800%	5.5	11,529	760,171
Jan	Year 2	748,642	0.2800%	4.5	9,433	758,075
Feb	Year 2	748,642	0.2800%	3.5	7,337	755,979
Mar	Year 2	748,642	0.2800%	2.5	5,240	753,883
Apr	Year 2	748,642	0.2800%	1.5	3,144	751,787
May	Year 2	748,642	0.2800%	0.5	1,048	749,690
Total		8,983,707				9,134,633

Note #1: For the initial rate year, enter zero for the first five months, June Year 1 through October Year 1. Enter 1/12 of Step 8 for the months Nov Year 1 through May Year 2.

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	9,134,633	0.2800%	775,145	8,385,065
Jul	Year 2	8,385,065	0.2800%	775,145	7,633,399
Aug	Year 2	7,633,399	0.2800%	775,145	6,879,628
Sep	Year 2	6,879,628	0.2800%	775,145	6,123,746
Oct	Year 2	6,123,746	0.2800%	775,145	5,365,748
Nov	Year 2	5,365,748	0.2800%	775,145	4,605,628
Dec	Year 2	4,605,628	0.2800%	775,145	3,843,379
Jan	Year 3	3,843,379	0.2800%	775,145	3,078,995
Feb	Year 3	3,078,995	0.2800%	775,145	2,312,472
Mar	Year 3	2,312,472	0.2800%	775,145	1,543,802
Apr	Year 3	1,543,802	0.2800%	775,145	772,980
May	Year 3	772,980	0.2800%	775,145	-
Total with interest				9,301,736	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest		9,301,736
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 9)	$	-
Revenue Requirement for Year 3		9,301,736

9 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2009)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Copperstone Substation (b0468)	(C) Monthly Additions Northeast Pocono Reliability Project CWIP	(D) Monthly Additions Susq-Rose CWIP < 500kV (b0487.1)	(E) Monthly Additions Susq-Rose PIS < 500kV (b0487.1)	(F) Monthly Additions Susq-Rose CWIP >= 500kV (b0487)	(G) Monthly Additions Susq-Rose PIS >= 500kV (b0487)	(H) Weighting	(I) Other Plant In Service Amount (A x H)	(J) Copperstone Substation Amount (B x H) (b0468)	(K) NPR CWIP Amount (C x H)	(L) Susq-Rose CWIP Amount (D x H) < 500kV (b0487.1)	(M) Susq-Rose PIS Amount (E x H) < 500kV (b0487.1)	(N) Susq-Rose CWIP Amount (F x H) >= 500kV (b0487)
CWIP Balance Dec (prior yr.)				763,531		78,249,508		12			-	9,162,374		938,994,099
Jan	13,118,042	23,639	0	(115,211)	272,202	12,615,433	1,881,343	11.5	150,857,486	271,852	-	(1,324,927)	3,130,323	145,077,480
Feb	7,939,606	366	0	274,967	109,843	12,160,827	104,399	10.5	83,365,867	3,847	-	2,887,154	1,153,352	127,688,684
Mar	33,162,755	3,686	0	(7,883)	259	22,710,120	174,590	9.5	315,046,173	35,017	-	(74,889)	2,461	215,746,140
Apr	28,805,462	20,415	0	(247,138)	492,020	17,169,176	192,431	8.5	244,846,431	173,528	-	(2,100,673)	4,182,170	145,937,996
May	13,207,095		0	44,897	-	16,958,018	11,673	7.5	99,053,210	-	-	336,728	-	127,185,135
Jun	50,222,188		30,423,848	44,897	-	15,963,850	2,400,220	6.5	326,444,220	-	197,755,014	291,831	-	103,765,025
Jul	18,078,755		8,678,100	44,897	-	19,652,382	50,216	5.5	99,433,150	-	47,729,550	246,934	-	108,088,101
Aug	7,307,471		6,202,400	44,897	-	22,157,288	50,216	4.5	32,883,621	-	27,910,800	202,037	-	99,707,796
Sep	4,160,607		6,225,962	186,032	-	18,581,523	50,216	3.5	14,562,125	-	21,790,868	651,112	-	65,035,331
Oct	34,252,711		5,398,500	102,596	179,404	14,102,372	20,066,429	2.5	85,631,778	-	13,496,250	256,490	448,510	35,255,930
Nov	38,376,383		-1,952,301	35,118	-	20,816,591	50,216	1.5	57,564,575	-	(2,928,452)	52,677	-	31,224,887
Dec	72,349,142		2,890,000	-	-	17,987,599	50,216	0.5	36,174,571	-	1,445,000	-	-	8,993,800
Total	320,980,217	48,107	57,866,509	1,171,600	1,053,728	289,124,687	25,082,165		1,545,863,205	484,244	307,199,030	10,586,846	8,916,815	2,152,700,401

New Transmission Plant Additions and CWIP (weighted by months in service)

Input to Line 17 of Appendix A
Input to Line 35 of Appendix A
Month In Service or Month for CWIP

10 May Year 3 Post results of Step 9 on PJM web site
$ 252,535,502 Post results of Step 3 on PJM web site

11 June Year 3 Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2009 - May 31, 2010)
$ 252,535,502

(O) Copperstone Substation (I / 12) (b0171.2)	(P) Susq-Rose CWIP (J / 12) < 500kV (b0487.1)	(Q) Susq-Rose PIS (K / 12) < 500kV (b0487.1)	(R) Susq-Rose CWIP (L / 12) >= 500kV (b0487)	(S) Susq-Rose PIS (M / 12) >= 500kV (b0487)	Total
	275,991		41,321,203		
1,362,889	1,776	-	487,304	3,802	
255,747	4,986	-	710,908	5,625	
191,293	1,980	-	618,515	2,054	
1,458,361	5,633	-	564,761	674	
10,803,238	6,112	-	639,129	-	
-	6,260	-	2,864,637	-	
-	5,549	-	877,343	-	
-	4,993	-	960,016	-	
-	14,253	-	1,635,916	-	
-	11,975	-	(1,164,329)	3,333,333	
-	9,945	-	1,419,694	-	
-	3,176	-	358,190	-	
14,071,528	352,629	-	51,293,287	3,345,488	-
14,071,528		-		3,345,488	78,166,742
	352,629		51,293,287		51,645,916
4.07	4.98	-	3.79	9.49	

(O) Copperstone Substation (I / 12) (b0171.2)	(P) Susq-Rose CWIP (J / 12) < 500kV (b0487.1)	(Q) Susq-Rose PIS (K / 12) < 500kV (b0487.1)	(R) Susq-Rose CWIP (L / 12) >= 500kV (b0487)	(S) Susq-Rose PIS (M / 12) >= 500kV (b0487)	Total
	275,991		41,321,203		
1,362,889	1,776	-	487,304	3,802	
255,747	4,986	-	710,908	5,625	
191,293	1,980	-	618,515	2,054	
1,458,361	5,633	-	564,761	674	
10,035,834	8,007	-	706,406	1,161	
50,442	(1,596)	-	620,822	796	
13,019	11,314	-	728,086	671	
148,379	51,061	-	1,419,800	493	
39,366	6,409	-	1,255,639	27	
(371)	(30,701)	-	(1,676,765)	3,531,533	
(36,885)	15,136	-	1,632,593	8,404	
2,061	12,630	9,149	710,849	57,560	
13,520,135	362,626	9,149	49,100,120	3,612,800	
13,520,135		9,149		3,612,800	84,835,712
	362,626		49,100,120		49,462,746
4.08	6.30	11.50	4.47	9.65	

(O) Susq-Rose PIS Amount (G x H) >= 500kV (b0487)	(P) Other Plant In Service (I / 12)	(Q) Copperstone Substation (J / 12) (b0468)	(R) NPR CWIP (K / 12)	(S) Susq-Rose CWIP (L / 12) < 500kV (b0487.1)	(T) Susq-Rose PIS (M / 12) < 500kV (b0487.1)	(U) Susq-Rose CWIP (N / 12) >= 500kV (b0487)	(V) Susq-Rose PIS (O / 12) >= 500kV (b0487)	Total
			-	763,531		78,249,508		
21,635,445	12,571,457	22,654	-	(110,411)	260,860	12,089,790	1,802,954	
1,096,190	6,947,156	321	-	240,596	96,113	10,640,724	91,349	
1,658,605	26,253,848	2,918	-	(6,241)	205	17,978,845	138,217	
1,635,664	20,403,869	14,461	-	(175,056)	348,514	12,161,500	136,305	
87,548	8,254,434	-	-	28,061	-	10,598,761	7,296	
15,601,430	27,203,685	-	16,479,585	24,319	-	8,647,085	1,300,119	
276,188	8,286,096	-	3,977,463	20,578	-	9,007,342	23,016	
225,972	2,740,302	-	2,325,900	16,836	-	8,308,983	18,831	
175,756	1,213,510	-	1,815,906	54,259	-	5,419,611	14,646	
50,166,073	7,135,981	-	1,124,688	21,374	37,376	2,937,994	4,180,506	
75,324	4,797,048	-	(244,038)	4,390	-	2,602,074	6,277	
25,108	3,014,548	-	120,417	-	-	749,483	2,092	
92,659,301	128,821,934	40,354	25,599,919	882,237	743,068	179,391,700	7,721,608	
	128,821,934	40,354			743,068		7,721,608	137,326,964
			25,599,919	882,237		179,391,700		205,873,856
	7.18	1.93	6.69	2.96	3.54	4.55	8.31	

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3	A	137	Net Plant Carrying Charge without Depreciation	18.3495%
4	B	144	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.2087%
5	C		Line B less Line A	0.8593%

6 **FCR if a CIAC**

Line		Formula Line		
7	D	138	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	5.9150%

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.**

Line	Instruction	Details		Susquehanna - Roseland CWIP (b0487) >= 500kV	Actual Susquehanna - Roseland PIS (b0487) >= 500kV	Projected Susquehanna - Roseland PIS (b0487) >= 500kV	Hosensack Wavetrap (b0171.2)	Alburtis Wavetrap (b0172.1)	Juniata Wavetrap (b0284.2)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42.00	42.00	42.00	42.00	42.00	42.00
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	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125	125	125	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		18.3495%	18.3495%	18.3495%	18.3495%	18.3495%	18.3495%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		19.4236%	19.4236%	19.4236%	18.3495%	18.3495%	18.3495%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified	Investment		179,391,700	25,316,858	25,082,165	86,626	62,067	123,504
18	Line 17 divided by line 12	Annual Depreciation Exp		-	602,825	597,194	2,063	1,478	2,941
19	Month in which project is placed in service (e.g. Jan=1)	Month in Service or Month for CWIP		-		8.31			

Line	Details		Susquehanna - Roseland CWIP (b0487.1) < 500kV	Actual Susquehanna - Roseland PIS (b0487.1) < 500kV	Projected Susquehanna - Roseland PIS (b0487.1) < 500kV	Stanton 4th Transformer (b0791)	Actual Copperstone Substation (b0468)	Projected Copperstone Substation (b0468)
11	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes	Yes	Yes
12	Life		42.00	42.00	42.00	42.00	42.00	42.00
13	CIAC	(Yes or No)	No	No	No	No	No	No
14	Increased ROE (Basis Points)		125	125	125	0	0	0
15	11.68% ROE		18.3495%	18.3495%	18.3495%	18.3495%	18.3495%	18.3495%
16	FCR for This Project		19.4236%	19.4236%	19.4236%	18.3495%	18.3495%	18.3495%
17	Investment		882,237	2,843,479	1,053,728	3,733,895	22,663,432	48,107
18	Annual Depreciation Exp		-	67,702	25,089	88,902	539,606	1,145
19	Month in Service or Month for CWIP		-		3.54			1.93

Line		Invest Yr	CWIP (b0487) Beginning	Depreciation	Ending	Revenue	Actual PIS (b0487) Beginning	Depreciation	Ending	Revenue	Projected PIS (b0487) Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	5,534,456	-	5,534,456	433,645	-	-	-	-	-	-	-	-
22	W Increased ROE	2008	5,534,456	-	5,534,456	453,741	-	-	-	-	-	-	-	-
23	W 11.68 % ROE	2009	25,703,638	-	25,703,638	3,744,759	-	-	-	-	-	-	-	-
24	W Increased ROE	2009	25,703,638	-	25,703,638	3,928,397	-	-	-	-	-	-	-	-
25	W 11.68 % ROE	2010	32,334,326	-	32,334,326	7,002,398	1,707,870	17,350	1,690,519	172,037	-	-	-	-
26	W Increased ROE	2010	32,334,326	-	32,334,326	7,346,350	1,707,870	17,350	1,690,519	181,239	-	-	-	-
27	W 11.68 % ROE	2011	41,267,823	-	41,267,823	8,153,565	1,690,519	40,664	1,649,856	366,037	-	-	-	-
28	W Increased ROE	2011	41,267,823	-	41,267,823	8,573,934	1,690,519	40,664	1,649,856	382,443	-	-	-	-
29	W 11.68 % ROE	2012	49,100,120	-	49,100,120	10,122,906	6,771,155	164,250	6,606,905	1,526,277	-	-	-	-
30	W Increased ROE	2012	49,100,120	-	49,100,120	10,644,117	6,771,155	164,250	6,606,905	1,598,510	-	-	-	-
31	W 11.68 % ROE	2013	179,391,700	-	179,391,700	32,917,437	24,904,453	164,250	24,740,203	4,703,946	25,082,165	233,614	24,848,551	2,017,257
32	W Increased ROE	2013	179,391,700	-	179,391,700	34,844,248	24,904,453	164,250	24,740,203	4,989,678	25,082,165	233,614	24,848,551	2,121,661
33	W 11.68 % ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-
34	W Increased ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-
35	W 11.68 % ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
36	W Increased ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
37	W 11.68 % ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
38	W Increased ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
39	W 11.68 % ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
40	W Increased ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
41	W 11.68 % ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
42	W Increased ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
43	W 11.68 % ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
44	W Increased ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
45	W 11.68 % ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
46	W Increased ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
47	W 11.68 % ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
48	W Increased ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
49	W 11.68 % ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
50	W Increased ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
51	W 11.68 % ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
52	W Increased ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
53	W 11.68 % ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
54	W Increased ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
55	W 11.68 % ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
56	W Increased ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
57	W 11.68 % ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
58	W Increased ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
59	W 11.68 % ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
60	W Increased ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
61			-	-	-	-	-	-	-	-	-	-	-	-
62														

Line		Invest Yr	Hosensack Beginning	Depreciation	Ending	Revenue	Alburtis Beginning	Depreciation	Ending	Revenue	Juniata Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	86,626	1,454	85,172	12,921	62,067	991	61,076	8,811	-	-	-	-
22	W Increased ROE	2008	86,626	1,454	85,172	12,921	62,067	991	61,076	8,811	-	-	-	-
23	W 11.68 % ROE	2009	85,172	2,063	83,109	19,836	61,076	1,478	59,598	14,223	123,504	2,941	120,563	28,723
24	W Increased ROE	2009	85,172	2,063	83,109	19,836	61,076	1,478	59,598	14,223	123,504	2,941	120,563	28,723
25	W 11.68 % ROE	2010	83,109	2,063	81,047	19,614	59,598	1,478	58,121	14,064	120,563	2,941	117,623	28,413
26	W Increased ROE	2010	83,109	2,063	81,047	19,614	59,598	1,478	58,121	14,064	120,563	2,941	117,623	28,413
27	W 11.68 % ROE	2011	81,047	2,063	78,984	17,668	58,121	1,478	56,643	12,669	117,623	2,941	114,682	25,599
28	W Increased ROE	2011	81,047	2,063	78,984	17,668	58,121	1,478	56,643	12,669	117,623	2,941	114,682	25,599
29	W 11.68 % ROE	2012	78,984	2,063	76,922	17,921	56,643	1,478	55,165	12,851	114,682	2,941	111,742	25,978
30	W Increased ROE	2012	78,984	2,063	76,922	17,921	56,643	1,478	55,165	12,851	114,682	2,941	111,742	25,978
31	W 11.68 % ROE	2013	76,922	2,063	74,859	15,799	55,165	1,478	53,687	11,329	111,742	2,941	108,801	22,905
32	W Increased ROE	2013	76,922	2,063	74,859	15,799	55,165	1,478	53,687	11,329	111,742	2,941	108,801	22,905
33	W 11.68 % ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-
34	W Increased ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-
35	W 11.68 % ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
36	W Increased ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
37	W 11.68 % ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
38	W Increased ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
39	W 11.68 % ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
40	W Increased ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
41	W 11.68 % ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
42	W Increased ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
43	W 11.68 % ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
44	W Increased ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
45	W 11.68 % ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
46	W Increased ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
47	W 11.68 % ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
48	W Increased ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
49	W 11.68 % ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
50	W Increased ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
51	W 11.68 % ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
52	W Increased ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
53	W 11.68 % ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
54	W Increased ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
55	W 11.68 % ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
56	W Increased ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
57	W 11.68 % ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
58	W Increased ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
59	W 11.68 % ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
60	W Increased ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
61			-	-	-	-	-	-	-	-	-	-	-	-
62														

Line		Invest Yr	CWIP (b0487.1) Beginning	Depreciation	Ending	Revenue	Actual PIS (b0487.1) Beginning	Depreciation	Ending	Revenue	Projected PIS (b0487.1) Beginning	Depreciation	Ending	Revenue
21	W 11.68 % ROE	2008	-	-	-	-	-	-	-	-	-	-	-	-
22	W Increased ROE	2008	-	-	-	-	-	-	-	-	-	-	-	-
23	W 11.68 % ROE	2009	395,068	-	395,068	43,820	-	-	-	-	-	-	-	-
24	W Increased ROE	2009	395,068	-	395,068	45,969	-	-	-	-	-	-	-	-
25	W 11.68 % ROE	2010	983,014	-	983,014	212,883	2,138,193	15,476	2,122,717	155,221	-	-	-	-
26	W Increased ROE	2010	983,014	-	983,014	223,339	2,138,193	15,476	2,122,717	162,084	-	-	-	-
27	W 11.68 % ROE	2011	338,809	-	338,809	66,941	2,122,717	50,909	2,071,807	460,250	-	-	-	-
28	W Increased ROE	2011	338,809	-	338,809	70,392	2,122,717	50,909	2,071,807	481,355	-	-	-	-
29	W 11.68 % ROE	2012	362,626	-	362,626	74,762	2,547,287	62,474	2,484,814	574,764	-	-	-	-
30	W Increased ROE	2012	362,626	-	362,626	78,611	2,547,287	62,474	2,484,814	601,141	-	-	-	-
31	W 11.68 % ROE	2013	882,237	-	882,237	161,886	2,703,748	67,702	2,636,046	551,402	1,053,728	19,783	1,033,945	209,506
32	W Increased ROE	2013	882,237	-	882,237	171,362	2,703,748	67,702	2,636,046	579,716	1,053,728	19,783	1,033,945	220,612
33	W 11.68 % ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-
34	W Increased ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-
35	W 11.68 % ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
36	W Increased ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-
37	W 11.68 % ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
38	W Increased ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-
39	W 11.68 % ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
40	W Increased ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-
41	W 11.68 % ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
42	W Increased ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-
43	W 11.68 % ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
44	W Increased ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-
45	W 11.68 % ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
46	W Increased ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-
47	W 11.68 % ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
48	W Increased ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-
49	W 11.68 % ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
50	W Increased ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-
51	W 11.68 % ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
52	W Increased ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-
53	W 11.68 % ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
54	W Increased ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-
55	W 11.68 % ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
56	W Increased ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-
57	W 11.68 % ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
58	W Increased ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-
59	W 11.68 % ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
60	W Increased ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-
61			-	-	-	-	-	-	-	-	-	-	-	-
62														

Line		Invest Yr	Stanton Beginning	Depreciation	Ending	Revenue	Actual Copperstone Beginning	Depreciation	Ending	Revenue	Projected Copperstone Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
21	W 11.68 % ROE	2008	-	-	-	-	-	-	-	-	-	-	-	-	$ 455,377		$ 455,377
22	W Increased ROE	2008	-	-	-	-	-	-	-	-	-	-	-	-	$ 475,473	$ 475,473	
23	W 11.68 % ROE	2009	-	-	-	-	-	-	-	-	-	-	-	-	$ 3,851,361		$ 3,851,361
24	W Increased ROE	2009	-	-	-	-	-	-	-	-	-	-	-	-	$ 4,037,148	$ 4,037,148	
25	W 11.68 % ROE	2010	-	-	-	-	-	-	-	-	-	-	-	-	$ 7,606,140		$ 7,606,140
26	W Increased ROE	2010	-	-	-	-	-	-	-	-	-	-	-	-	$ 7,975,046	$ 7,975,046	
27	W 11.68 % ROE	2011	3,733,895	25,673	3,708,222	237,250	918,555	11,846	906,709	108,883	-	-	-	-	$ 9,449,462		$ 9,449,462
28	W Increased ROE	2011	3,733,895	25,673	3,708,222	237,250	918,555	11,846	906,709	108,883	-	-	-	-	$ 9,911,193	$ 9,911,193	
29	W 11.68 % ROE	2012	3,708,222	88,902	3,619,320	835,093	906,709	21,870	884,838	204,296	-	-	-	-	$ 13,394,951		$ 13,394,951
30	W Increased ROE	2012	3,708,222	88,902	3,619,320	835,093	906,709	21,870	884,838	204,296	-	-	-	-	$ 14,016,520	$ 14,016,520	
31	W 11.68 % ROE	2013	3,619,320	88,902	3,530,418	736,715	22,244,731	539,606	21,705,126	4,522,382	48,107	1,056	47,051	9,690	$ 45,880,257		$ 45,880,257
32	W Increased ROE	2013	3,619,320	88,902	3,530,418	736,715	22,244,731	539,606	21,705,126	4,522,382	48,107	1,056	47,051	9,690	$ 48,226,087	$ 48,226,087	
33	W 11.68 % ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
34	W Increased ROE	2014	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
35	W 11.68 % ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
36	W Increased ROE	2015	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
37	W 11.68 % ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
38	W Increased ROE	2016	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
39	W 11.68 % ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
40	W Increased ROE	2017	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
41	W 11.68 % ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
42	W Increased ROE	2018	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
43	W 11.68 % ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
44	W Increased ROE	2019	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
45	W 11.68 % ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
46	W Increased ROE	2020	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
47	W 11.68 % ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
48	W Increased ROE	2021	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
49	W 11.68 % ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
50	W Increased ROE	2022	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
51	W 11.68 % ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
52	W Increased ROE	2023	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
53	W 11.68 % ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
54	W Increased ROE	2024	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
55	W 11.68 % ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
56	W Increased ROE	2025	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
57	W 11.68 % ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
58	W Increased ROE	2026	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
59	W 11.68 % ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
60	W Increased ROE	2027	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -	
61			-	-	-	-	-	-	-	-	-	-	-	-	$ -		$ -
62																	

On the formulas used in the Columns for lines 21+ are as follows:
For Plant in service: (first year means first year the project is placed in service)
"Beginning" is the investment on line 17 for the first year and is the "Ending" for the prior year after the first year
"Depreciation" is the annual depreciation in line 18 divided by twelve times the difference of thirteen minus line 19 in the first year and line 18 thereafter if "no" on line 13. "Depreciation" is "0" (zero) if "Yes" on line 13
"Ending" is "Beginning" less "Depreciation"
Revenue is "Ending" times line 16 for the current year times the quotient line 19 divided by 13 plus "Depreciation" for the first year and "Ending" times line 16 plus "Depreciation" thereafter

For CWIP:
Beginning is the line 17 for that year
Depreciation is not used
Ending is the same as Beginning
Revenue is Ending times line 16 for the current year

PPL Electric Utilities Corporation

Attachment 8 - Company Exhibit - Securitization Worksheet

Line #			
	Prepayments		
36	**Less Prepayments on Securitization Bonds**	0	(See FM 1, note to page 110, line 57)
	Administrative and General Expenses		
52	**Less Administrative and General Expenses on Securitization Bonds**	0	(See FM 1, note to page 114, line 4)
	Taxes Other Than Income		
78	**Less Taxes Other Than Income on Securitization Bonds**	0	(See FM 1, note to page 114, line 14)
	Long Term Interest		
81	**Less LTD Interest on Securitization Bonds**	0	(See FM 1, note to page 114, lines 62 + 63)
	Capitalization		
92	**Less LTD on Securitization Bonds**	0	(See FM 1, note to page 112, line 18)

Calculation of the above Securitization Adjustments

The amounts above are associated with transition bonds issued to securitize the recovery of retail stranded costs, pursuant to an Order entered by the Pennsylvania Public Utility Commission on May 21, 1999 at Docket No. R-00994637, in accordance with Pennsylvania's Electric Generation Customer Choice and Competition Act.

PPL Electric Utilities Corporation

Attachment 9 - Depreciation Rates

(A) Number	(B) Plant Type	(C) Estimated Life	(D) Mortality Curve	(E) Current Age	(F) Remaining Life	(G) Applied Depreciation Rate	(H) Gross Depreciable Plant $	(I) Accumulated Depreciation $	(J) Depreciable Balance $	(K) Depreciation Expense $
	Transmission									
350.4	Land Rights	70	S4	20.5	49.50	1.7360	106,432,096	38,292,118	68,139,978	1,182,908
352	Structures and Improvements	55	R4	19.5	35.50	3.1387	38,106,888	16,446,606	21,660,282	679,844
353	Station Equipment	47	R1	9.5	37.50	2.5168	587,715,827	171,973,565	415,742,262	10,463,254
354	Towers and Fixtures	65	R3	14.9	50.10	1.9428	392,737,876	131,108,820	261,629,056	5,082,851
354.2	Towers and Fixtures - Clearing Land and Rights of Way	70	R4	28.0	42.00	2.5947	11,764,501	6,680,362	5,084,139	131,916
355	Poles and Fixtures	55	R1.5	15.2	39.80	2.6718	100,036,114	42,023,879	58,012,235	1,549,992
355.2	Poles and Fixtures - Clearing Land and Rights of Way	70	R4	25.1	44.90	2.3463	7,410,808	3,888,147	3,522,661	82,650
356	Overhead Conductors and Devices	55	R3	16.7	38.30	2.6493	249,003,383	117,749,108	131,254,275	3,477,283
357	Underground Conduit	50	R4	19.5	30.50	3.2147	6,319,982	2,226,352	4,093,630	131,600
358	Underground Conductors and Devices	40	R3	11.5	28.50	3.7821	20,587,258	7,976,012	12,611,246	476,975
359	Roads and Trails	70	R4	25.4	44.60	2.0628	7,332,574	2,830,515	4,502,059	92,870
	General									
389.4	Land Rights	65	R4	40.2	24.80	3.4939	4,399	1,496	2,903	101
390.2	Structures and Improvements - Buildings	55	S0	36.7	18.30	1.8511	353,869,548	70,491,213	283,378,335	5,245,737
390.21	Structures and Improvements - Leaseholds	10	NA		6.50	-	741,658	298,463	443,195	0
390.4	Structures and Improvements - Air Conditioning	30	R2	8.4	21.60	4.5527	33,717,809	11,713,311	22,004,498	1,001,808
391.2	Office Furniture and Equipment - Furniture	20	NA		10.70	5.2241	19,703,132	8,021,882	11,681,250	1,029,302
391.4	Office Furniture and Equipment - Mechanical Equipment	15	NA		9.90	6.6627	2,664,883	768,184	1,896,699	177,553
391.6	Office Furniture and Equipment - Computer Equipment - General	5	NA		2.50	17.6160	2,924,466	743,215	2,181,251	515,173
391.8	Office Furniture and Equipment - Computer Equipment - Power Mgt System	7	NA		-	14.2800	38,155,394	38,155,394	0	0
392.1	Transportation Equipment - 5 Years	5	R4	1.2	3.80	41.6439	5,441,699	3,225,483	2,216,216	922,919
392.2	Transportation Equipment - 8 Years	8	S3	2.7	5.30	32.8374	18,314,882	10,893,758	7,421,124	2,436,901
392.3	Transportation Equipment - 10 Years	11	R2.5	5.3	5.70	7.4882	69,514,057	36,270,678	33,243,379	2,489,331
392.4	Transportation Equipment - Trailers	16	L1	0.7	15.30	9.0859	6,199,286	2,177,935	4,021,351	365,376
392.5	Transportation Equipment - 15 Years	14	L2	4.9	9.10	13.9748	3,171,751	1,210,777	1,960,974	274,041
392.6	Transportation Equipment - 20 Years	18	L1.5	6.4	11.60	10.5877	653,799	120,333	533,466	56,482
393	Store Equipment	25	NA		10.40	5.2284	2,438,586	1,015,038	1,423,548	127,499
394	Tools, Shop and Garage Equipment - Distribution Line Crews	20	NA		10.50	5.8304	4,927,326	1,764,024	3,163,302	287,285
394.2	Tools, Shop and Garage Equipment - Tools	20	NA		8.10	7.1341	285,954	108,970	176,984	20,400
394.4	Tools, Shop and Garage Equipment - Construction Department	20	NA		9.30	5.7911	1,582,631	722,948	859,683	91,652
394.6	Tools, Shop and Garage Equipment - Other	20	NA		12.50	4.9281	20,320,045	6,358,565	13,961,480	1,001,384
394.8	Tools, Shop and Garage Equipment - Garage Tools Support	20	NA		4.70	6.4244	5,298,994	3,667,657	1,631,337	340,431
395	Laboratory Equipment	20	NA		13.50	4.8134	5,006,766	1,729,336	3,277,430	240,996
396	Power Operated Equipment	15	NA		9.70	8.9870	1,794,193	1,002,190	792,003	161,245
397	Communication Equipment	15	NA		12.10	5.9016	12,489,002	10,687,609	1,801,393	737,056
398	Miscellaneous Equipment	20	NA		9.40	6.5915	2,017,803	495,913	1,521,890	133,003
	Intangible									
303.2	Intangible Computer Software	5	NA		3.00	20.00	100,444,873	44,262,683	56,182,190	17,110,857
303.4	Other Amortized Property	15	NA		-	6.67	1,035,137	1,035,137	-	19,320

Notes:

1 Columns (A), (B), (C), and (D) are fixed and cannot be changed absent Commission approval or acceptance.
2 Column (E) is based on the Estimated Life in Column (C) less the Remaining Life in Column (F) for those accounts for which using a Mortality Curve is identified.
3 Column (F) is the average remaining life of the assets in the account based on their vintage.
4 Column (G) is the depreciation rate from the Mortality Curve specified based on data in Columns (C) and (D).
5 Columns (H) and (I) are the depreciable gross plant investment and accumulated depreciation in the account or subaccount.
6 Column (J) is the depreciable net plant in the account or subaccount.
7 Column (K) is Column (G) multiplied by Column (J) for those accounts that have an identified Mortality Curve.
8 Each year, PPL Electric will provide a copy of the annual report submitted to the PA PUC that shows the calculation of the depreciation rates and expenses derived from Columns (C) and (D).
9 Every 5 years, PPL Electric will file with the Commission a depreciation study supporting its existing Estimated Life and Mortality Curve for each account or subaccount.
10 Column (K) for Accounts Nos. 303.2 and 303.4 are calculated using individual asset depreciation and, therefore, are not derived values.
11 Column (K) for Account No. 392.3 is net of capitalized depreciation expense. See the applicable note in FERC Form No. 1.
12 For those General Plant accounts that do not have Mortality Curves as indicated by "NA" in Column (D), additional detail is provided in Attachment 9 - Supplemental General Plant Depreciation Details.

PPL Electric Utilities Corporation

Attachment 9 - Supplemental
General Plant Depreciation Details

(A) Number	(B) Plant Type	(C) Estimated Life	(G) Applied Depreciation Rate	(H) Gross Depreciable Plant $	(I) Accumulated Depreciation $	(J) Depreciable Balance $	(K) Depreciation Expense $
	General						
390.21	Structures and Improvements - Leaseholds - Net Method	10	-	741,658	298,463	443,195	0
391.2	Office Furniture and Equipment - Furniture - Gross Method	20	4.9024	15,292,075	4,568,409	10,723,666	749,677
391.2	Office Furniture and Equipment - Furniture - Net Method	20	29.2011	4,411,057	3,453,473	957,584	279,625
				19,703,132	8,021,882	11,681,250	1,029,302
391.4	Office Furniture and Equipment - Mechanical Equipment - Gross Method	15	6.5247	2,619,706	728,335	1,891,371	170,928
391.4	Office Furniture and Equipment - Mechanical Equipment - Net Method	15	124.3373	45,177	39,849	5,328	6,625
				2,664,883	768,184	1,896,699	177,553
391.6	Office Furniture and Equipment - Computer Equipment - General- Gross Method	5	17.6160	2,924,466	743,215	2,181,251	515,173
391.8	Office Furniture and Equipment - Computer Equipment - Power Mgt System- Gross Method	7	14.2800	38,155,394	38,155,394	0	0
393	Store Equipment - Gross Method	25	4.0104	1,284,595	414,273	870,322	51,518
393	Store Equipment - Net Method	25	13.7343	1,153,991	600,765	553,226	75,982
				2,438,586	1,015,038	1,423,548	127,499
394	Tools, Shop and Garage Equipment - Distribution Line Crews - Gross Method	20	5.0000	2,371,043	708,816	1,662,227	118,552
394	Tools, Shop and Garage Equipment - Distribution Line Crews - Net Method	20	11.2408	2,556,283	1,055,209	1,501,074	168,733
				4,927,326	1,764,025	3,163,301	287,285
394.2	Tools, Shop and Garage Equipment - Tools - Gross Method	20	4.8015	133,692	28,573	105,119	6,419
394.2	Tools, Shop and Garage Equipment - Tools - Net Method	20	19.4545	152,262	80,397	71,865	13,981
				285,954	108,970	176,984	20,400
394.4	Tools, Shop and Garage Equipment - Construction Department - Gross Method	20	5.7824	1,574,680	719,188	855,492	91,054
394.4	Tools, Shop and Garage Equipment - Construction Department - Net Method	20	14.2857	7,951	3,761	4,190	599
				1,582,631	722,949	859,682	91,652
394.6	Tools, Shop and Garage Equipment - Gross Method	20	4.6677	17,157,995	3,633,648	13,524,347	800,885
394.6	Tools, Shop and Garage Equipment - Net Method	20	45.8669	3,162,050	2,724,917	437,133	200,499
				20,320,045	6,358,565	13,961,480	1,001,384
394.8	Tools, Shop and Garage Equipment - Garage Tools Support - Gross Method	20	4.4306	1,396,531	161,523	1,235,008	61,874
394.8	Tools, Shop and Garage Equipment - Garage Tools Support - Net Method	20	70.2842	3,902,463	3,506,134	396,329	278,557
				5,298,994	3,667,657	1,631,337	340,431
395	Laboratory Equipment - Gross Method	20	5.4823	2,923,820	551,443	2,372,377	160,293
395	Laboratory Equipment - Net Method	20	8.9169	2,082,946	1,177,893	905,053	80,703
				5,006,766	1,729,336	3,277,430	240,996
396	Power Operated Equipment - Gross Method	15	6.5726	814,124	252,678	561,446	53,509
396	Power Operated Equipment - Net Method	15	46.7285	980,069	749,512	230,557	107,736
				1,794,193	1,002,190	792,003	161,245
397	Communication Equipment - Gross Method	15	5.6662	11,808,423	10,290,566	1,517,857	669,086
397	Communication Equipment - Net Method	15	23.9723	680,579	397,043	283,536	67,970
				12,489,002	10,687,609	1,801,393	737,056
398	Miscellaneous Equipment - Gross Method	20	4.3796	1,115,990	178,083	937,907	48,876
398	Miscellaneous Equipment - Net Method	20	14.4057	901,813	317,830	583,983	84,127
				2,017,803	495,913	1,521,890	133,003

Notes:

1 This schedule shows additional detail for those General Plant accounts that do not have a Mortality Curve. The calculation of Depreciation Expense by the Gross Plant Method (i.e., Column (G) multiplied by Column (H)) and the Net Plant Method (i.e., Column (G) multiplied by Column (J)) is shown separately for the assets in each account subject to each such method. Assets purchased new are depreciated using the Gross Plant Method. Assets purchased used are depreciated using the Net Plant Method (i.e., over their remaining economic life).

Attachment 4F - AEP East Formula Rate Summary Update

Formula Rate Update for AEP East subsidiaries in PJM

To be Effective July 1, 2013 through June 30, 2014
Docket No ER08-1329

Pursuant to PJM OATT Attachment H-14A (Formula Rate Implementation Protocols), AEP has calculated its Annual Transmission Revenue Requirements (ATRR) to produce the "Annual Update" for the Rate Year beginning July 1, 2013 through June 30, 2014. All the files pertaining to the Annual Update are to be posted on the PJM website in PDF format. The first file provides the ATRR 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 increase effective July 1, 2013 from $26,339.82 per MW per year to $29,042.93 per MW per year with the AEP annual revenue requirement increasing from $646,136,826 to $676,950,019.

The AEP Schedule 1A rate increased from $.0643 per MWh to $.0829 per MWh.

An annual revenue requirement of $8,440,878 for RTEP projects (including true-up and interest) is to be collected under PJM Tariff Schedule 12. The RTEP Project revenue requirement includes:

1. b0839 (Twin Branch) $1,187,960
2. b0318 (Amos 765/138 kV Transformer) $1,952,440
3. b0504 (Hanging Rock) $1,014,540
4. b0570 (East Side Lima) $24,004
5. b1034.1 (Torrey-West Canton) $528,784
6. b1034.6 (138kV circuit South Canton Station) $424,916
7. b1231 (West Moulton Station) $933,951
8. b1465.2 (Rockport Jefferson 300 MVAR bank) $44,386
9. b1465.3 (Rockport Jefferson 765 kV line) $1,301,059
10. b1712.2 (Altavista-Leesville 138kV line) $301,999
11. b1864.1 (Kammer 345/138 kV transformers) $682,672
12. b1864.2 (West Bellaire-Brues 138 kV circuit) of $44,166

Formula Rate Update 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 July 1, 2013
Docket No ER10-355

Pursuant to Attachment H-20A (Formula Rate Implementation Protocols) in PJM Tariff, AEP has calculated its Annual Transmission Revenue Requirements (ATRR) to produce the "Annual Update" for the Rate Year beginning July 1, 2013 through June 30, 2014. All the files pertaining to the Annual Update are also posted on the PJM website in PDF format along with supporting workpapers. The first file provides the ATRR and rates for Network transmission service and Scheduling System Control and Dispatch Service, Schedule 1A.

AEP network service rate will increase effective July 1, 2013 from $1,091.09 per MW per year or $2.99/MW Day to $2,992.32 per MW per year or $8.20/MW Day with the AEP annual revenue requirement increasing from $26,765,400 to $69,746,794.

The AEP Transmission Companies' Schedule 1A rates are not applicable because they are handled via AEP Operating Companies.

An annual revenue requirement of $7,439,363 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 $1,438,660
2. b1465.2 (Rockport Jefferson-MVAR Bank) $1,578,782
3. b2048 (Tanners Creek 345/138 kV transformer) $461,439
4. b0570 (Lima-Sterling) $1,835,044
5. b1231 (Wapakoneta-West Moulton) $736,412
6. b1034.1 (South Canton-Wagenhals-Wayview 138 kV) $443,007
7. b1034.8 (South Canton Wagenhals Station) $244,284
8. b1864.2 (West Bellaire-Brues 138 kV Circuit) $124,755
9. b1870 (Ohio Central Transformer) $576,980