COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

MAR 28 2008

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF

AN EXAMINATION OF THE APPLICATION	)	
OF THE FUEL ADJUSTMENT CLAUSE OF	)	
KENTUCKY POWER COMPANY FROM	)	CASE NO. 2007-00522
MAY 1, 2007 THROUGH OCTOBER 31, 2007	)	

KENTUCKY POWER COMPANY

RESPONSES TO COMMISSION STAFF'S
DATA REQUESTS OF THE MARCH 18, 2008 HEARING

March 28, 2008

Kentucky Power Company

REQUEST

Please refer to PSC 1st Set, Item No. 4, pages 78 through 92. Please reconcile the column KWH Metered to the Company's October 2007 Fuel Adjustment Clause Sales Schedule, Page 3 of 5, Line 5, Inter-System Sales Including Interchange Out. Please provide an explanation of interchange out.

RESPONSE

The Company believes this is the result of rounding. The data provided in the response to the data request was presented in KWH. The data presented in the October, 2007 fuel adjustment clause schedule was rounded to the nearest MWH. That is, on PSC 1st Set, Item No. 4 pages 79 through 92 the total KWH Metered column total is 511,357,344. On the October 2007 Fuel Adjustment Clause Sale Schedule, Page 3 of 5, Line 5, Inter-System Sales Including Interchange Out the total KWH is 511,357,000. The difference between the two is 344 KWH. In reviewing the Company's response to Item No. 4, Page 84 of 92, Account 4470035 Total, KWH Metered column has an amount of 5,827,344. This amount should have been 5,827,000. By replacing the 5,827,344 amount with 5,827,000, the result will reconcile with the amount filed in the October 2007 monthly filing.

The term "interchange out" refers to the portion of KPCo's KWH and their associated costs that are assigned to off-system sales. The term "inter-system sales" refers to the portion of KPCo's KWH and their associated costs that are assigned to sales to affiliated companies.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Please refer to PSC 1st Set, Item No. 17b. The Company's response indicates it is providing "the bid evaluation that identifies proposal ranking and the selected vendor." That information does not appear to have been provided. Please indicate where the information is provided in the response or provide, as requested in the Data Request, "the bid tabulation sheet or corresponding document that ranked the proposals....[and] the reasons for each selection.

RESPONSE

Revised Confidential Attachment 17b provides details regarding each offer and highlights the vendors selected. In addition to this information, KPCo considers additional factors including: vendor financial status, existing supply base, mode of delivery and term of current agreements. AEP-Fuel Procurement East selected 4 vendors from which 4 contracts have been or are expected to be executed from the AEP System solicitation. The final vendor selection is based on a business decision resulting from evaluating all of the previously mentioned factors and determining which suppliers best meet these requirements at the time. For additional information regarding the executed contracts, please see Company's response to PSC First Set Item No. 6.

WITNESS: Jason T Rusk

TERM RESPONSES

No.	Company	Product	Term	Applicable Dates	Price	TPM	Moist %	Ash %	Sulfur %	Btu	SO2 #	(H=½W) Fusion	Synfuel/Coal	Mode	Shipping Point
1	Alliance Coal Sales														
1	Alliance Coal Sales														
6	Alpha Coal Sales Co., LLC														
6	Alpha Coal Sales Co., LLC														
17	Appalachian Fuels, Inc.														
17	Appalachian Fuels, Inc.														
20	Appalachian Fuels, Inc.														
20	Appalachian Fuels, Inc.														
20	Appalachian Fuels, Inc.														
23	Appalachian Fuels, Inc.														
23	Appalachian Fuels, Inc.														
29	COALTRADE, LLC														
29	COALTRADE, LLC														
31	Genesis Coal Corp. by CSV, Inc.														
31	Genesis Coal Corp. by CSV, Inc.														
31	Genesis Coal Corp. by CSV, Inc.														
36	ICG, LLC														
36	ICG, LLC														
37	ICG, LLC														
37	ICG, LLC														
37	ICG, LLC														
38	ICG, LLC														
38	ICG, LLC														
38	ICG, LLC														
38	ICG, LLC														
39	ICG, LLC														
39	ICG, LLC														
39	ICG, LLC														
39	ICG, LLC														
39	ICG, LLC														
40	ICG, LLC														
40	ICG, LLC														
41	ICG, LLC														
41	ICG, LLC														
42	Logan & Kanawha Coal Co.														
42	Logan & Kanawha Coal Co.														
42	Logan & Kanawha Coal Co.														
48	Marshall Resources														
48	Marshall Resources														
48	Marshall Resources														
49	Massey Utility Sales Co.														
49	Massey Utility Sales Co.														
49	Massey Utility Sales Co.														
56	Premier Elkhorn Coal Co.														
56	Premier Elkhorn Coal Co.														
56	Premier Elkhorn Coal Co.														
56	Premier Elkhorn Coal Co.														
56	Premier Elkhorn Coal Co.														
57	Raven Crest Minerals, LLC														
57	Raven Crest Minerals, LLC														
57	Raven Crest Minerals, LLC														

No.	Company	Product	Term	Applicable Dates	Price	TPM	Moist %	Ash %	Sulfur %	Btu	SO2 #	Fusion	Synfuel/Coal	Mode	Shipping Point
57	Raven Crest Minerals, LLC														
57	Raven Crest Minerals, LLC														
58	Rhino Energy LLC														
58	Rhino Energy LLC														
61	Trinity Coal Marketing LLC														
61	Trinity Coal Marketing LLC														
62	Trinity Coal Marketing LLC														
62	Trinity Coal Marketing LLC														
62	Trinity Coal Marketing LLC														
63	Trinity Coal Marketing LLC														
63	Trinity Coal Marketing LLC														
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63	Trinity Coal Marketing LLC														
64	Trinity Coal Marketing LLC														
64	Trinity Coal Marketing LLC														
64	Trinity Coal Marketing LLC														
64	Trinity Coal Marketing LLC														
64	Trinity Coal Marketing LLC														
78	Central Coal Company														
78	Central Coal Company														
3	Alliance Coal Sales														
3	Alliance Coal Sales														
12	Appalachian Fuels, Inc.														
12	Appalachian Fuels, Inc.														
13	Appalachian Fuels, Inc.														
13	Appalachian Fuels, Inc.														
13	Appalachian Fuels, Inc.														
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22	Appalachian Fuels, Inc.														
22	Appalachian Fuels, Inc.														
22	Appalachian Fuels, Inc.														
24	Appalachian Fuels, Inc.														
24	Appalachian Fuels, Inc.														
25	Argus Energy, LLC														
25	Argus Energy, LLC														
25	Argus Energy, LLC														

No.	Company	Product	Term	Applicable Dates	Price	TPM	Moist %	Ash %	Sulfur %	Btu	SO2 #	Fusion	Synfuel/Coal	Mode	Shipping Point
60	S.M. & J.														
60	S.M. & J.														
60	S.M. & J.														
60	S.M. & J.														
60	S.M. & J.														
60	S.M. & J.														
73	Trinity Coal Marketing LLC														
73	Trinity Coal Marketing LLC														
74	Trinity Coal Marketing LLC														
74	Trinity Coal Marketing LLC														
74	Trinity Coal Marketing LLC														
75	Trinity Coal Marketing LLC														
75	Trinity Coal Marketing LLC														
75	Trinity Coal Marketing LLC														
75	Trinity Coal Marketing LLC														
76	Trinity Coal Marketing LLC														
76	Trinity Coal Marketing LLC														
76	Trinity Coal Marketing LLC														
76	Trinity Coal Marketing LLC														
76	Trinity Coal Marketing LLC														

SPOT RESPONSES

No.	Company	Term and Applicable Dates	Price	Product	TPM	Moist %	Ash %	Sulfur %	Btu	SO2 #	(H=½W) Fusion	Synfuel or Coal	Mode	Shipping Point
1	Alliance Coal, LLC													
6	Appalachian Fuels, Inc.													
9	COALTRADE													
12	Genesis Coal Corp													
14	ICG, LLC													
15	ICG, LLC													
16	ICG, LLC													
22	Pike Letcher Synfuel LLC													
28	Trinity Coal Marketing LLC													
35	Central Coal Company													
4	Appalachian Fuels, Inc.													
7	Appalachian Fuels, Inc.													
31	Appalachian Fuels, Inc.													
18	Kiva Coal Sales, LLC													
11	Laurel Creek Co., Inc.													
21	Pevler Coal Sales Company, Inc.													
27	SM&J, Inc.													
30	Trinity Coal Marketing LLC													

Kentucky Power Company

REQUEST

Please refer to the Kentucky Power's Notice of Determination of Adjustment filed March 11, 2008 in this proceeding. Please provide a copy of Appalachian Power Company's February 29, 2008 filing with the West Virginia Public Service Commission reflecting the adjustment of inter-company settlements between APCo and Kentucky Power for the thirty-day period preceding the discovery of the meter inaccuracy.

RESPONSE

Attached is a copy of Appalachian Power Company's February 29, 2008 filing with the West Virginia Public Service Commission, which included the adjustment of the inter-company settlement between APCo and KPCo for the thirty-day period preceding the discovery of the meter issue. The one-month May 2007 adjustment was included in APCo's financial records.

WITNESS: Errol K Wagner

BEFORE THE
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
CASE NO. 08-______-E-GI

IN THE MATTER OF

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY

EXPANDED NET ENERGY COST
FOR THE
TWELVE MONTHS ENDING DECEMBER 31, 2007

DIRECT TESTIMONY AND EXHIBITS

FEBRUARY 29, 2008

BEFORE THE
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
CASE NO. 08-______-E-GI

IN THE MATTER OF

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY

EXPANDED NET ENERGY COST
FOR THE
TWELVE MONTHS ENDING DECEMBER 31, 2007

DIRECT TESTIMONY AND EXHIBITS

FEBRUARY 29, 2008

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
TESTIMONY
OF
TERRY R. EADS

DIRECT TESTINOMY OF
TERRY R. EADS
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 08-____E-GI

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Terry R. Eads. My business address is Suite 1100, Chase Tower, 707 Virginia Street, East, Charleston, West Virginia. I am employed by Appalachian Power Company (APCo) as Director - Regulatory Services for West Virginia.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND UTILITY EXPERIENCE.

A. I graduated with a Bachelor of Science Degree - Electrical Engineering from West Virginia Institute of Technology in September 1970. In 1984, I attended the American Electric Power Management Development Program at the College of Administrative Science of The Ohio State University. I also attended "The Executive Program" at the University of Virginia's Colgate Darden Graduate School of Business Administration in 1987.

After graduation from college, I was employed by APCo as an Electrical Engineer in its Beckley Division. In July 1975, I transferred to Michigan Power Company (MPCo), a former operating company subsidiary of American Electric Power Company, Inc. (AEP), as Engineering Supervisor in the Transmission and Distribution Department; in November 1979, I became Electric Customer Services Supervisor.

In September 1981, I assumed the responsibilities of Director of Rates and Tariffs for MPCo. In that capacity I was responsible for the supervision and direction of MPCo's Rate Department relative to rate matters of MPCo's gas and electric operations. Subsequently, I was assigned the further responsibility for MPCo's gas supply and gas transportation functions. In October 1987, following the sale by MPCo of its gas operation, I transferred to Indiana and Michigan Power Company (I&M), another operating company subsidiary of AEP, as Administrative Assistant to the Vice President. My duties included the continued responsibilities for the rate matters of MPCo, as well as other assigned responsibilities for I&M.

In September 1990, I transferred back to APCo where I assumed the position of Director of Rates. On January 1, 1996, following a reorganization with a focus toward individual State responsibilities, I assumed my present position in West Virginia.

Q. ~~PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS~~ DIRECTOR-REGULATORY SERVICES FOR WEST VIRGINIA.

A. My duties include the supervision and direction of the Regulatory Services Department, which has the responsibility for rate and regulatory matters affecting APCo's West Virginia jurisdiction and Wheeling Power Company (WPCo). Both APCo and WPCo are operating subsidiaries of AEP.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of both APCo and WPCo. Hereinafter I will refer to these entities either individually as APCo or WPCo, or jointly as the "Companies".

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?

A. Yes. In addition to previous testimonies before the Public Service Commission of West Virginia (the Commission) on behalf of APCo and WPCo, I have testified on behalf of APCo before the Virginia State Corporation Commission and the Federal Energy Regulatory Commission (FERC). I have also provided testimony before the

Michigan Public Service Commission and the FERC on behalf of other operating company subsidiaries of AEP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide a general overview of the Companies' request in this proceeding to increase its rates and charges. I will also provide specific support for both the revised Construction Surcharges and revised ENEC Over-Recovery Amortization rate credits related to the Bank, to become effective for service rendered on and after July 1, 2008. I also am supporting a request for a minor modification to the temporary and limited exemption the Commission granted the Companies in Case No- 07-0248-E-GI with regard to the filing for certain approvals pursuant to WV Code 24-2-12.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring TRE Exhibit Nos. 2 through 8.

Q. PLEASE PROVIDE A GENERAL OVERVIEW OF THE COMPANIES' FILING.

A. On July 26, 2006, the Commission issued an Order approving a Joint Stipulation and Agreement for Settlement in Case No. 05-1278-E-PC-PW-42T (the "2005 Base Case"). Among other things, that Order provided for the implementation of Expanded Net Energy Cost (ENEC) rate components, Construction Surcharges and ENEC Over-recovery Amortization Credits in the Companies' tariff rates and charges effective on and after July 28, 2006. Moreover, the Order provided that the Company would file for any adjustments in these various rate components by March 1st of each year thereafter, with the modified rates to become effective on and after July 1st. In accordance with the provisions of the Order, the Companies are herewith filing the ENEC rate components, Construction Surcharges and ENEC Over-recovery Amortization Credits they propose to become effective for service rendered on and after July 1, 2008.

Q. PLEASE DISCUSS THE CHANGES IN ANNUAL REVENUE SUPPORTED IN THE COMPANIES' FILING.

A. The Companies are requesting changes in their approved rates and charges that will produce a net increase in annual revenue of approximately $156 million. The following table identifies the specific components of the overall revenue increase being requested:

Description	Amount	Percentage Revenue Increase [1]
ENEC	$ 134,782,101	
ENEC Prior-period /Under-recovery	$ 454,205	
Net ENEC	$ 135,236,306	14.5 %
Construction Surcharge	$ 17,234,346	1.8 %
Musser Acquisition Charge	$ (998,494)	(0.1) %
Reliability Expenditures	$ 4,782,000	0.5 %
Increase in Revenue	$ 156,254,158	16.7 %

As the table indicates, the Companies are requesting an increase in ENEC revenues of $135,236,306, an increase for Reliability Expenditures of $4,782,000, and a decrease in revenues related to the recent acquisition of the former Musser Companies located in McDowell County, WV. Support for these requested increases is provided through the testimony of Company witnesses Rusk, Allen and Ferguson. I

[1] Percentages based on current annual West Virginia retail revenues totaling approximately $934,000,000.

am sponsoring the revenue increase of $17,234,346 related to the Construction Surcharge.

The Companies are also proposing changes in the current ENEC Over-Recovery Amortization Credits applicable to the various customer classes / special contracts. These bill credits have been providing customers with refunds of an over-recovery of ENEC costs that was accrued by APCo at the end of 2000. As will be discussed later in my testimony, the revised credit rate factors will increase the level of future credits for some customers, decrease the credit for others, or eliminate the credit completely in certain circumstances.

Q. PLEASE PROVIDE A GENERAL OVERVIEW OF THE CHANGES IN THE COMPANIES' ENEC COSTS THAT RESULT IN THE NEED FOR AN INCREASE OF $135 MILLION IN ENEC REVENUES.

A. The ENEC is comprised of costs that tend to be volatile and for which the Companies have a limited ability to control their effects on the cost of providing electric service. These include the cost of fuel consumed at power plants owned by APCo, expenses associated with power and energy purchased by both APCo and WPCo to meet their customer's growing energy needs, the costs to transmit power across the regional transmission grid and variable environmental-related costs.

Of the approximate $135 million requested increase in the Companies' ENEC revenues, roughly $85 million, or 63% of the increase, can be attributed to fuel-related expenses that include the costs of coal, energy losses on the transmission system and allowances for NOx and SO_2 emissions. With respect to increases for fuel, more than 95% of the energy generated at APCo's generating plants is produced from coal. As discussed in the testimony of Company witness Rusk, environmental constraints, a shortage of trained mining personnel and difficulties in obtaining required mining permits applicable to both current and proposed mining operations, combined with high demand in both domestic and export markets for the types of coal required for APCo's generating plants, is causing dramatic increases in market price for coal.

The fuel-related costs of transmission losses and emission allowance costs have also increased. The increased cost of transmission losses follows approval by the Federal Energy Regulatory Commission of a revised methodology for pricing losses on the PJM System. Increased emission allowance costs are primarily the result of environmental requirements that now require year-round operation of the SCR's at the Amos and Mountaineer plants to reduce NOx emissions.

Of the remaining $50 million increase, approximately $29 million relates to purchases of additional power supplies by APCo in order to satisfy a growing demand for power and energy by the Companies' customers. As an example of this growth, in February 2007, the service territory served by APCo experienced an all-time peak demand for electric energy of approximately 8,100 megawatts, or about 1,000 megawatts more than the peak previously set by the Company's customers in 2004. Although lower than the previous year, in January of this 2008, the Company experienced a peak demand of approximately 7,850 megawatts. Since these demand levels are greater than the combined capacity of APCo's own sources of generation, the Company must purchase additional energy supplies to serve its customers. An additional $21 million of projected increased purchased power expense relates to the energy requirements of customers in the service territory supplied by WPCo. As discussed in the testimony of Company witness Allen, this increase can be attributed in great measure to increases in environmental-related investments at, and the cost of fuel for, the generating facilities owned by WPCo's wholesale power supplier, Ohio Power Company.

Q. PLEASE DISCUSS THE $17.2 MILLION INCREASE IN THE CONSTRUCTION SURCHARGE.

A. The Commission's order in the 2005 Base Case provided for adjustments in subsequent ENEC proceedings to recover the costs of the Wyoming-Jacksons Ferry 765 kV line and the individual flue-gas desulfurization units ("FGD") being installed at the Mountaineer Generating Plant and on Units 1, 2 and 3 at the John Amos Generating Plant. In general, each project would be afforded rate of return treatment on the year-end EPIS/CWIP plant balance, at a 10.5% rate of return on common equity. If a given project has been placed in service by no later than March 1st of the year the ENEC factors become effective, then in addition to the return on the year end balances, APCo would be permitted to recover its projected depreciation, taxes and other fixed operating expenses over the next succeeding ENEC recovery period.

Q. WHICH PROJECTS ARE PRESENTLY IN SERVICE?

A. The Wyoming-Jacksons Ferry 765 kV line went into service on June 20, 2006 and the Mountaineer FGD was placed in service on February 20, 2007.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE REVENUE REQUIREMENTS ASSOCIATED WITH THESE PROJECTS.

A. The Companies prepared what could be characterized as stand-alone cost-of-service studies for each of the assets. Pages 2 and 3 of TRE Exhibit No. 2 provide the individual revenue requirement calculations on a West Virginia retail jurisdictional basis for the 765 kV line and the Mountaineer FGD, respectively. Page 4 of TRE Exhibit No. 2 sets forth the revenue requirement on a West Virginia retail jurisdictional basis for FGD facilities on Units 1, 2 and 3 at the John Amos plant, all of which are still under construction.

The starting point for computing the revenue requirement for each facility was to determine the rate base equivalent of each project as of December 31, 2007. This involved a review of each project's level of year-end investment, and deducting accumulated depreciation and deferred taxes for projects in service or, for projects not in service, deducting the amount of AFUDC reversed as a result of the cash return allowance provided pursuant to the final Order in the 2005 Base Case. An overall rate of return, grossed up for income taxes, was then applied to arrive at the revenue requirement attributable to the rate base. Thereafter, additional expense items related to depreciation, fixed O&M expense and taxes were added for those facilities that are in service to arrive at the revenue requirement.

Q. WHAT DEPRECIATION RATES WERE USED TO CALCULATE ANNUAL DEPRECIATION EXPENSE?

A. The Companies utilized the current West Virginia depreciation rates for transmission facilities and the Mountaineer plant.

Q. PLEASE DISCUSS THE FIXED O&M COMPONENT.

A. The fixed O&M component for the Mountaineer FGD was based on the forecast of such costs for the twelve-months ending June 30, 2009, the period for which the ENEC rates will be in effect. Company witness Allen provided this cost information to me. The fixed O&M component for the transmission line was based on projections of direct O&M charges for the same twelve-month period.

Q. WHAT RATE OF RETURN WAS APPLIED TO EACH FACILITY IN ORDER TO DETERMINE THE REVENUE REQUIREMENT?

A. Consistent with the terms of the Order in the 2005 Base Case, the rate of return applied to each facility was based on the thirteen-month average capital structure as of December 31, 2007, including a 10.5% rate of return on common equity. After adjustment for taxes, this results in an overall after-tax rate of return of 7.651%.

Q. PLEASE DISCUSS THE WEST VIRGINIA REVITALIZATION TAX CREDIT ENTRY.

A. West Virginia provides a tax credit for new production investments after they have been placed into service, equal to 10% of the capitalized investment. This credit is allowed as an offset against APCo's Business and Occupation (B&O) tax over a 10-year period. Accordingly, an annual tax credit has been reflected as a reduction in the revenue requirement attributable to the Mountaineer FGD.

Q. PLEASE DISCUSS THE REDUCTION IN WEST VIRGINIA B&O TAX THAT HAS BEEN INCORPORATED INTO THE REVENUE REQUIREMENT FOR THE MOUNTAINEER PLANT.

A. The current West Virginia B&O tax provides two distinct capacity tax rates applicable to generating capacity installed in West Virginia. For non-scrubbed units, the tax rate is $22.78 per kW of taxable capacity; and for scrubbed units, the rate is $20.70 per kW. A total reduction of $1,530,437 in APCo's annual B&O tax expense has been reflected in the calculation of the Mountaineer FGD revenue requirement.

Q. PLEASE SUMMARIZE THE REVENUE REQUIREMENT ASSOCIATED WITH ALL THE CONSTRUCTION INVESTMENTS AS OF DECEMBER 31, 2007.

A. As shown on Page 1 of TRE Exhibit No. 2, based on investments as of December 31, 2007, the following are the West Virginia jurisdictional revenue requirements associated with each of the projects, as well as the total revenue requirement to be collected by means of the Construction Surcharge, beginning on July 1, 2008.

	Total West Virginia Revenue Requirement
Wyoming Jacksons Ferry 765 kV Line	$15,953,286
Mountaineer FGD	$33,559,422
John Amos Unit #3 FGD	$ 5,664,644
John Amos Units #1 and #2 FGDs	$16,881,942
Total	$72,059,294

Q. PLEASE IDENTIFY TRE EXHIBIT NO. 3 AND TRE EXHIBIT NO. 4.

A. TRE Exhibit No. 3 sets forth the Companies' proposed Construction Surcharges applicable to the Companies' tariffs and/or special contracts effective on and after July 1, 2008.

TRE Exhibit No. 4 is a billing analysis that shows the incremental increase in annual revenue to the Companies of $17,234,346 from the Construction Surcharges. The annual increase is the difference between the revenue requirement of $72,059,294 to be collected over the twelve months ended June 30, 2009 using the proposed Construction Surcharge rate factors and $54,824,947 calculated on the basis of the current Construction Surcharge rates.

Q. HOW WERE THE PROPOSED CONSTRUCTION SURCHARGES ON TRE

EXHIBIT NO. 3 DEVELOPED?

A. The proposed surcharges were developed by allocating the total West Virginia jurisdictional revenue requirement of $72,059,294 to the individual customer classes/special contracts. Because the revenue requirement is associated with transmission and generation facilities whose costs do not vary with the level of generation, the Companies allocated each year's requirement to the customer classes and special contract customers based on their coincident peak demand relationships. Moreover, because the revenue requirements are for future periods beginning in July 2008 and will be applicable to both APCo and WPCo customers, the Companies utilized the forecast coincident peak demand relationships used by Company witness Ferguson to allocate demand-related ENEC.

Q. WHAT COST RECOVERY BASIS WAS SELECTED FOR USE IN DEVELOPING SURCHARGES FOR THE VARIOUS CUSTOMER CLASSES?

A. In the Companies' tariffs that include a demand charge component, the rate factors were developed as a demand surcharge. For those tariffs that bill on an energy-only basis, such as the residential class, the class demand responsibility was reflected as a kilowatt-hour charge using forecast demand/energy relationships. In the case of special contract customers, the basis of the surcharge varied depending on the specifics of each contract's cost recovery mechanism.

Q. WHAT BILLING DETERMINANTS WERE USED TO CALCULATE THE SURCHARGE FACTORS?

A. The surcharges were calculated using the forecast demand and energy billing determinants reflected in the development of the proposed ENEC rate factors to become effective July 1, 2008.

Q. PLEASE DISCUSS THE TREATMENT OF THE ENEC OVER-RECOVERY BALANCE (THE "BANK").

A. The Commission's Order in the 2005 Base Case provided that the Companies would implement rate credits designed to feed back one-third of the balance in the Bank, or approximately $17,069,000, over the eleven months ending June 30, 2007. Thereafter, treatment of any residual balance and interest was to be determined in subsequent ENEC proceedings. In Case No. 07-0248-E-GI (the "2007 ENEC Case") the Commission approved a settlement agreement providing that the credit rate factors previously approved in the 2005 Base Case would remain in effect for a second annual period ending June 30, 2008. In the instant ENEC proceeding, the Company must address the treatment of the residual balance of the Bank, plus accumulated interest.

Q. WHAT IS THE COMPANIES' PROPOSAL FOR THE TREATMENT OF THE RESIDUAL BALANCES OF THE BANK AND THE RELATED INTEREST?

A. In this proceeding, the Companies are proposing to refund the balance of the Bank and related interest that the Company estimates will exist on June 30, 2008. Based on actual balances of principal and interest as of January 31, 2008 and estimated refunds thereafter through June 30, 2008, the Company estimates that the funds available for refund will total approximately $18,060,000. This is comprised of approximately $13,320,000 of residual Bank principal and $4,740,000 of interest.

Q. HAVE YOU CALCULATED REVISED ENEC OVER-RECOVERY AMORTIZATION RATE FACTORS DESIGNED TO REFUND THIS BALANCE TO CUSTOMERS?

A. Yes. TRE Exhibit No. 5 sets forth the proposed rate factors to be applied beginning July 1, 2008 and continuing through June 30, 2009.

Q. WILL ALL TARIFF CLASSES AND SPECIAL CONTRACT CUSTOMERS THAT PREVIOUSLY RECEIVED BILL CREDITS BE ENTITLED TO THE ADDITIONAL REFUND?

A. No. Based on actual refunds through January 2008 and estimated refunds through June 30, 2008, a few customer classes will have received greater bill credits than they were approved to receive under the Commission's Order in the 2005 Base Case. These customer classes, and the amount of excess refund credits, include the Company's School Service Schedule - primary voltage service ($14,100), the General Service Time of Day Schedule - primary voltage service ($1,902) and the Large General Service Schedule – subtransmission voltage service ($47,363). In addition, two of the Company's special contract customers who requested an early distribution of their full share of the Bank and interest will not receive any additional refund credits.

Q. WHAT IS THE COMPANIES' PROPOSAL REGARDING BOTH THE COLLECTION OF THESE SPECIFIC OVER-REFUNDED AMOUNTS AND ANY POTENTIAL FUTURE OVER OR UNDER COLLECTION OF THE BANK AND INTEREST?

A. The Companies propose that when the ENEC Over-Recovery Amortization credit rate factors terminate on June 30, 2009, any residual balances as of that date payable to the customers or any amounts owed to the Companies, be treated as additional ENEC deferred over or under-recovery balances.

Q. PLEASE DISCUSS TRE EXHIBIT NO. 6.

A. TRE Exhibit No. 6 details the estimated level of annual credits each customer class/special contract is currently receiving, the amount of annual credit they will receive beginning July 1, 2008, and the resulting change in annual revenue. This exhibit also shows that the level of total annual credits to eligible customers beginning July 1, 2008 is approximately $1.7 million less what the current factors would produce during the same period. Although the amount of overall credit will be less, as the exhibit shows, some customer groups will experience a larger credit than in the past, and others will receive a smaller credit. Special contract customers who were not originally provided a refund allocation, or those who have already received a full refund have been excluded from the analysis.

Q. PLEASE DESCRIBE TRE EXHIBIT NOS. 7 AND 8.

A. TRE Exhibit No. 7 contains the Second Revised Sheet No. 27 of the Companies' P.S.C. West Virginia Tariff No. 12 (Appalachian Power Company) and P.S.C. West Virginia Tariff No. 17 (Wheeling Power Company), which reflects the revised Construction Surcharges to become effective for service rendered on and after July 1, 2008. TRE Exhibit No. 8 contains the First Revised Sheet No. 28 of the Companies' P.S.C. West Virginia Tariff No. 12 (Appalachian Power Company) and P.S.C. West Virginia Tariff No. 17 (Wheeling Power Company), which reflects the revised ENEC Over-Recovery Amortization Credits to become effective for service rendered on and after July 1, 2008.

Q: ARE THE COMPANIES PROPOSING ANY CHANGE IN THE TEMPORARY AND LIMITED EXEMPTION GRANTED IN CASE NO. 07-0248-E-GI?

A. Yes. They are requesting one slight modification. In the 2007 ENEC proceeding, the parties proposed and the Commission adopted a two-year duration for the exemption. It was contemplated that the Commission would have the benefit of two reports and, in the 2009 ENEC proceeding, to quote the Commission's June 1, 2007 Order in the 2007 ENEC proceeding, "the Commission could evaluate how the exemption has operated and whether the partial exemption should be further extended." However, the June 22, 2007 Order granting the two-year exemption evidently accorded it a retroactive starting date, as it provided that the exemption "will automatically end with the Companies' filing of the 2009 ENEC" (emphasis added). The result of this timing will be that it will be impossible for the exemption to be "extended" by the Commission's final ENEC Order in 2009, as it will have already terminated by March 1, 2009, at the latest, with the ENEC filing. The Companies are proposing therefore, that in this 2008 ENEC case the Commission extend the partial and limited exemption through July 1, 2009, or at least the entry date of the Commission's final Order in the 2009 case. This will prevent APCo and the Companies' ratepayers from being automatically deprived of the benefit of this valuable flexibility during the approximate four-month duration of the 2009 ENEC proceeding. The Commission can then determine in the 2009 case whether it wishes to extend, modify, or terminate the exemption.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

TRE Exhibit No. 7
Proposed Tariff Schedules

Appalachian Power Company / Wheeling Power Company
Summary of Incremental Revenue Requirements
Construction Surcharge - Effective 7/1/2008

	Revenue Requirement 7/1/2008 - 6/30/2009
Transmission Investment	
Wyoming-Jacksons Ferry 765 kV Line	$ 15,953,286
Environmental Investments	
Mountaineer FGD	$ 33,559,422
John Amos FGD (Unit 3)	$ 5,664,644
John Amos FGD (Units 1 & 2)	$ 16,881,942
Total Revenue Requirement	**$ 72,059,294**

Wyoming-Jacksons Ferry 765 kV Line
In Service June 2006

		6/30/2006	12/31/2006	12/31/2007	
Rate Base					
Gross Plant In-service					
Depreciable Plant		$ 291,400,030	$ 289,981,626	$ 289,053,027	
Non-Depreciable Plant		$ 12,944,108	$ 13,146,752	$ 16,468,244	
		$ 304,344,138	$ 303,128,378	$ 305,521,271	
Accumulated Depreciation		$ -	$ 2,376,250	$ 7,088,160	
Net Plant		$ 304,344,138	$ 300,752,128	$ 298,433,111	
Accumulated Deferred Taxes			$ (2,974,321)	$ (8,628,511)	
Year End Rate Base			$ 297,777,807	$ 289,804,600	$ 289,804,600
Cost of Service					
Revenue Requirement on Rate Base					$ 22,172,851
Depreciation Expense @	1.63%				$ 4,711,564
Property Tax					$ 1,963,636
Transmission O&M					$147,749
FIT					$ 6,831,173
SIT					$ 187,641
Total Cost of Service					$ 36,014,614
West Virginia Jurisdictional Share @	44.2967%				$ 15,953,286

Accumulated Depreciation	12/31/2006	12/31/2007
Beginning Bal	$ -	$ 2,376,250
Additions	$ 2,376,250	$ 4,711,910
Ending Balance	$ 2,376,250	$ 7,088,160

Accumulated Tax Depreciation	12/31/2006	12/31/2007
Rate	3.7500%	7.2190%
Beginning Bal	$ -	$ 10,874,311
Additions	$ 10,874,311	$ 20,866,738
Ending Balance	$ 10,874,311	$ 31,741,049
Temporary Difference	$ 8,498,061	$ 24,652,889
Tax Rate	35.00%	35.00%
Accumulated DFIT	2,974,321	8,628,511

	FIT		SIT
Return	$ 22,172,851	Return	$ 22,172,851
		Rev. For FIT	6,831,173
less:		less:	
Interest Exp.	9,486,386	Interest Exp.	9,486,386
book / tax Dep	16,154,828	book / tax Dep	16,154,828
	(3,468,364)		3,362,810
FIT Rate	35.00%	SIT Rate	5.285%
	(1,213,927)		177,724
Deferred Fit	5,654,190	Deferred SIT	0
Total FIT	4,440,263	Total SIT	177,724
	1.5385		1.0558
FIT	6,831,173	SIT	187,641

2007 YEAR END AVERAGE CAPITAL STRUCTURE AND COST OF CAPITAL

	Weight	Rate	Weighted Rate
Debt	58.089%	5.635%	3.273%
Preferred Stock	0.375%	4.350%	0.016%
Common Equity	41.536%	10.500%	4.361%
	100.000%		
ROR			7.651%

O&M Expense

	2008	2009	7/1/08 - 6/30/09
Aerial Structural Inspection @2/year	$4,000	$4,000	$4,000
Aerial Vegetation Inspection @ 2/year	$3,500	$3,500	$3,500
Breaker Maintenance / Inspections	$5,000	$5,000	$5,000
Ground-based Inspection	$18,900	$18,900	$18,900
Access Road Maintenance	$2,800	$2,800	$2,800
Vegetation removal	$75,098	$152,000	$113,549
	$109,298	$186,200	$147,749

Property Taxes July 1, 2008 - June 30, 2009	
WV Portion of the Line	$ 532,770
VA Portion of the Line	$ 1,430,866
Total	$ 1,963,636

Effective State Tax Rate (STR)	5.285%
Federal Tax Rate (FTR)	35.000%

Mountaineer Plant FGD
In Service Date 2/20/2007

		12/31/2006	12/31/2007	
Gross Plant - net of AFUDC Reversal		$ 521,294,955	$ 569,394,433	
Non-depreciable Plant n Service			$ 1,112,721	
Accumulated Depreciation			$ 8,308,582	
Net Plant in Service			$ 562,198,572	
CWIP (uncompleted associated W/Os)			$ 29,544,385	
Net Plant Balance		$ 521,294,955	$ 591,742,957	
Accumulated Deferred Taxes			$ (4,565,298)	
Year End Rate Base			$ 587,177,659	$ 587,177,659
Cost of Service (Non-Variable Expenses)				
Revenue Requirement on Rate Base				$ 44,924,761
Depreciation Expense @	1.93%			$ 10,989,313
WV Revitilization Credit				$ (5,871,777)
Property Tax				$ 116,940
O&M				$ 11,812,254
FIT				$ 13,840,747
SIT				$ 1,478,744
Total Environmental Cost of Service				$ 77,290,983
Less: B&O Tax Reduction for Scrubbed Units				
Mountaineer Taxable Generating Capacity		735,787 kW		
Tax Rates per kW				
Scrubbed Units		20.70	$/Kw -Year	
Non-Scrubbed Units		22.78	$/Kw -Year	
Tax Rate Difference		-$2.08	$/Kw -Year	$ (1,530,437)
Total Incremental Cost of Service				$ 75,760,546
West Virginia Jurisdictional Share @	**44.2967%**			**$ 33,559,422**

Accumulated Depreciation	
Beginning Bal	$ -
Additions	$ 8,308,582
Ending Balance	$ 8,308,582

Accumulated Tax Depreciation	
Rate	3.7500%
Beginning Bal	$ -
Additions	$ 21,352,291
Ending Balance	$ 21,352,291
Temporary Difference	$ 13,043,709
Tax Rate	35.00%
Accumulated DFIT	4,565,298

		FIT	
Return	$	44,924,761	Return
			Rev. For FIT
less:			less:
Interest Exp.		19,220,516	Interest Exp.
book / tax Dep		13,043,709	book / tax De
		12,660,536	
FIT Rate		35.00%	SIT Rate
		4,431,188	
Deferred Fit		4,565,298	Deferred SIT
Total FIT		8,996,486	Total SIT
		1.5385	
	FIT	13,840,747	SIT

2007 YEAR END AVERAGE CAPITAL STRUCTURE AND COST OF CAPITAL

	Weight	Rate	Weighted Rate
Debt	58.089%	5.635%	3.273%
Preferred Stock	0.375%	4.350%	0.016%
Common Equity	41.536%	10.500%	4.361%
	100.000%		
ROR			7.651%

O&M Expense

	7/1/2008 - 6/30/2009
FGD Non-Outage Maintenance Outage & Installation (NOM	$ 1,161,045
FGD Base Cost of Operations (BCO)	$ 2,605,000
Purge Stream BCO	$ 1,658,827
Gypsum Handling / Diposal	$ 4,384,658
2008 -2009 Outage	$ -
FGD Labor	$ 2,002,724
	$ 11,812,254

Property Taxes July 1, 2008 - June 30, 2009
$ 116,940

State Tax Rate (STR)	5.285%
Federal Tax Rate (FTR)	35.000%

John Amos Plant

		12/31/2007
John Amos Unit #3		
EPIS (work orders closed to plant)		$ 7,966,267
CWIP (APCo Share)		$ 115,517,695
AFUDC Debt Reversal (Allowed Cash Return)		$ (332,458)
Net CWIP / EPIS		$ 123,151,524
Cash Return		$ 9,422,281
FIT		$ 2,902,885
SIT		$ 462,794
Total Cost of Service		$ 12,787,960
West Virginia Jurisdictional Share @	44.2967%	$ 5,664,644

	FIT		SIT
Return	$ 9,422,281	Return	$ 9,422,281
		Rev. For FIT	2,902,885
less:		less:	
Interest Exp.	4,031,209	Interest Exp	4,031,209
Add. Deprec.	0	Add. Deprec	0
	5,391,072		8,293,957
FIT Rate	35.00%	SIT Rate	5.285%
	1,886,875		438,336
Deferred FIt	0	Deferred SIT	0
Total FIT	1,886,875	Total SIT	438,336
	1.5385		1.0558
FIT	2,902,885	SIT	462,794

John Amos Units #1 and #2		
CWIP		$ 368,136,377
AFUDC Reversal (Allowed Cash Return)		$ (1,116,530)
Net CWIP		$ 367,019,847
Cash Return on CWIP		$ 28,080,563
FIT		$ 8,651,264
SIT		$ 1,379,233
Total Cost of Service		$ 38,111,060
West Virginia Jurisdictional Share @	44.2967%	$ 16,881,942

	FIT		SIT
Return	$ 28,080,563	Return	$ 28,080,563
		Rev. For FIT	8,651,264
less:		less:	
Interest Exp.	12,013,929	Interest Exp.	12,013,929
book / tax Dep	0	book / tax Dep	0
	16,066,633		24,717,897
FIT Rate	35.00%	SIT Rate	5.285%
	5,623,322		1,306,341
Deferred FIt	0	Deferred SIT	0
Total FIT	5,623,322	Total SIT	1,306,341
	1.5385		1.0558
FIT	8,651,264	SIT	1,379,233

2007 YEAR END AVERAGE CAPITAL STRUCTURE AND COST OF CAPITAL

	Weight	Rate	Weighted Rate
Debt	58.089%	5.635%	3.273%
Preferred Stock	0.375%	4.350%	0.016%
Common Equity	41.536%	10.500%	4.361%
	100.000%		
ROR			7.651%

State Tax Rate (STR)	5.285%
Federal Tax Rate (FTR)	35.000%

TRE Exhibit No. 3

Appalachian Power Company / Wheeling Power Company
Construction Surcharge
Effective July 1, 2008 - June 30, 2009

Tariff Schedule / Contract		Energy Charge Cents/kWh	Demand Charge $/kW
RS		0.476	
RS-LM-TOD			
	On-peak	0.405	
	Off-Peak	0.030	
SWS		0.484	
SGS		0.326	
SGS-LM-TOD			
	On-peak	0.375	
	Off-Peak	0.049	
SS	Secondary		1.137
	Primary		1.111
	AF	0.384	
MGS	Secondary		0.980
	Primary		0.958
	Subtransmission		0.954
	Transmission		0.932
	AF	0.384	
GS-TOD			
	On-Peak Sec.	0.768	
	Off-Peak Sec	0.105	
	On-Peak Pri.	0.808	
	Off-Peak Pri.	0.090	
LGS	Secondary		1.461
	Primary		1.428
	Subtransmission		1.422
	Transmission		1.389
LCP	Secondary		1.258
	Primary		1.230
	Subtransmission		1.224
	Transmission		1.196

Tariff Schedule / Contract		Energy Charge Cents/kWh	Demand Charge $/kW
IP	Secondary		1.550
	Primary		1.514
	Subtransmission		1.508
	Transmission		1.967
Special Contract A			
	Firm Demand		2.152
	ATOD Demand		1.271
Special Contract B			0.732
Special Contract C			
	P1	0.712	
	P2	0.907	
	P3	8.869	
	P4	29.453	
Special Contract D			1.183
Special Contract E			
	On-Peak Sec.	0.531	
	Should Peak Sec.	0.186	
	Off-Peak Sec	0.122	
	On-Peak Pri.	0.635	
	Should Peak Pri.	0.231	
	Off-Peak Pri.	0.146	
Special Contract F _1/			
Special Contract G			1.679
Special Contract H			1.899
Special Contract I			1.209
OL		0.000	
SLS		0.000	

_1/ IP Subtran. Tariff Rate - per Special Contract

Appalachian Power / Wheeling Power
Billing Analysis - Construction Surcharge
12 months ended June 30, 2009

TRE Exhibit No. 4
Page 1 of 2

Tariff Schedule / Contract		Billing Energy kWh	Billing Demand kW	Rates Effective 7/1/2007 Cents/kWh or $/kW	Rates Effective 7/1/2007 Revenue	Rates Effective 7/1/2008 Cents/kWh or $/kW	Rates Effective 7/1/2008 Revenue	Change in Revenue
RS		6,397,935,610		0.358	$ 22,904,608	0.476	$ 30,427,181	$ 7,522,572
RS-TOD								
	On-Peak	227,115		0.277	$ 629	0.405	$ 919	$ 290
	Off-Peak	534,040		0.020	$ 107	0.030	$ 162	$ 55
SWS		97,867,973		0.368	$ 360,154	0.484	$ 474,006	$ 113,852
SGS		248,163,664		0.264	$ 655,152	0.326	$ 808,649	$ 153,497
SS	Secondary		100,405	0.864	$ 1,040,996	1.137	$ 1,370,129	$ 329,134
	Primary		8,902	0.838	$ 89,519	1.111	$ 118,688	$ 29,168
	AF	4,637,315		0.300	$ 13,912	0.384	$ 17,799	$ 3,887
	Total SS Class							
MGS	Secondary		481,206	0.708	$ 4,088,323	0.980	$ 5,660,474	$ 1,572,150
	Primary		46,543	0.687	$ 383,701	0.958	$ 534,914	$ 151,212
	Subtransmission		2,825	0.669	$ 22,675	0.954	$ 32,337	$ 9,662
	Transmission		0	0.658	$ -	0.932	$ -	$ -
	AF	2,590,914		0.298	$ 7,721	0.384	$ 9,944	$ 2,223
GS-TOD								
	On-Peak Sec.	9,335,547		0.587	$ 54,800	0.768	$ 71,724	$ 16,925
	Off-Peak Sec	12,096,082		0.077	$ 9,314	0.105	$ 12,657	$ 3,343
	On-Peak Pri.	3,516,202		0.569	$ 20,007	0.808	$ 28,420	$ 8,413
	Off-Peak Pri.	5,577,060		0.091	$ 5,075	0.090	$ 5,015	$ (60)
LGS	Secondary		250,053	1.102	$ 3,306,695	1.461	$ 4,384,268	$ 1,077,573
	Primary		28,939	1.070	$ 371,581	1.428	$ 495,743	$ 124,162
	Subtransmission		9,461	1.042	$ 118,301	1.422	$ 161,401	$ 43,100
	Transmission		0	1.024	$ -	1.389	$ -	
LCP	Secondary		23,056	1.038	$ 287,183	1.258	$ 348,169	$ 60,986
	Primary		159,533	1.008	$ 1,929,711	1.230	$ 2,353,764	$ 424,053
	Subtransmission		225,876	0.981	$ 2,659,009	1.224	$ 3,318,698	$ 659,689
	Transmission		96,073	0.965	$ 1,112,521	1.196	$ 1,379,209	$ 266,688

TRE Exhibit No. 4
Page 2 of 2

Tariff Schedule / Contract	Billing Energy kWh	Billing Demand kW	Rates Effective 7/1/2007 Cents/kWh or $/kW	Rates Effective 7/1/2007 Revenue	Rates Effective 7/1/2008 Cents/kWh or $/kW	Rates Effective 7/1/2008 Revenue	Change in Revenue
P Secondary		14,073	1.301	$ 219,710	1.550	$ 261,771	$ 42,060
Primary		166,872	1.262	$ 2,527,116	1.514	$ 3,032,553	$ 505,437
Subtransmission		147,563	1.230	$ 2,178,036	1.508	$ 2,670,474	$ 492,438
Transmission-Other		88,592	1.209	$ 1,285,296	1.967	$ 2,091,576	$ 806,280
Special Contract A		80,000					
Firm Demand		3,000	1.695	$ 61,020	2.152	77,470	$ 16,450
ATOD Demand		77,000	1.001	$ 924,924	1.271	1,174,272	$ 249,348
Special Contract B		110,000	0.577	$ 761,640	0.732	965,883	$ 204,243
Special Contract C							
P1	2,546,575		0.307	$ 7,818	0.712	$ 18,141	$ 10,323
P2	566,669		0.391	$ 2,216	0.907	$ 5,141	$ 2,926
P3	2,354		3.822	$ 90	8.869	$ 209	$ 119
P4	0		12.693	$ -	29.453	$ -	$ -
Special Contract D		40,883	0.736	$ 361,082	1.183	580,582	$ 219,499
Spec. Contr. E							
Secondary							
On-Peak Sec.	704,212		0.465	$ 3,275	0.531	$ 3,738	$ 463
Should Peak Sec.	2,107,291		0.163	$ 3,435	0.186	$ 3,920	$ 486
Off-Peak Sec	691,893		0.107	$ 740	0.122	$ 845	$ 105
Primary							
On-Peak Pri.	148,953		0.571	$ 851	0.635	$ 947	$ 96
Should Peak Pri.	433,677		0.208	$ 902	0.231	$ 1,004	$ 102
Off-Peak Pri.	144,954		0.131	$ 190	0.146	$ 211	$ 21
Special Contract G		56,930	1.120	$ 765,143	1.679	1,146,824	$ 381,681
Special Contract H		325,234	1.482	$ 5,783,961	1.899	7,412,595	$ 1,628,634
Special Contract I		41,152	1.004	$ 495,804	1.209	596,867	$ 101,063
Total Revenue Requirement				$ 54,824,947		$ 72,059,294	$ 17,234,346

Appalachian Power Company / Wheeling Power Company
ENEC Over-Recovery Amortization Rate Credits
Effective July 1, 2008 - June 30, 2009

TRE Exhibit No.5

Tariff Schedule / Contract		Energy Charge Cents/kWh	Demand Charge $/kW
RS		(0.151)	
RS-LM-TOD			
	On-peak	(0.151)	
	Off-Peak	(0.151)	
SWS		(0.099)	
SGS		(0.211)	
SGS-LM-TOD			
	On-peak	(0.243)	
	Off-Peak	(0.032)	
SS	Secondary	(0.060)	(0.07693)
	Primary	0.022	0.04580
	AF	(0.087)	
MGS	Secondary	(0.049)	(0.05819)
	Primary	(0.081)	(0.09186)
	Subtransmission	(0.022)	(0.03511)
	Transmission	0.000	0.00000
	AF	(0.096)	
GS-TOD			
	On-Peak Sec.	(0.328)	
	Off-Peak Sec	(0.045)	
	On-Peak Pri.	0.046	
	Off-Peak Pri.	0.005	
LGS	Secondary	(0.084)	(0.14944)
	Primary	(0.211)	(0.34102)
	Subtransmission	0.092	0.10822
	Transmission	0.000	0.00000
LCP	Secondary	(0.052)	(0.10827)
	Primary	(0.045)	(0.06226)
	Subtransmission	(0.056)	(0.08654)
	Transmission	(0.020)	(0.02700)

Tariff Schedule / Contract		Energy Charge Cents/kWh	Demand Charge $/kW
IP	Secondary	(0.059)	(0.12308)
	Primary	(0.050)	(0.09638)
	Subtransmission	(0.064)	(0.13875)
	Transmission	(0.061)	(0.11941)
Special Contract A		0.000	0.00000
Special Contract B			($14,552.73)
Special Contract C		(0.047)	
Special Contract D		0.000	0.00000
Special Contract E		(0.087)	
Special Contract F _1/		(0.064)	(0.13875)
Special Contract G		0.000	0.00000
Special Contract H		0.000	0.00000
Special Contract I			($18,389.97)
OL		(0.059)	
SLS		(0.093)	

_1/ IP Subtran. Tariff Rate - per Special Contract

Highlighed Areas indicate tariffs projected to be over-refunded as of June 30, 2008 - zero factor to be applied this period.

Appalachian Power / Wheeling Power

Billing Analysis - ENEC Over-Recovery Amortization Credit

12 months ended June 30, 2009

TRE Exhibit No. 6

Tariff Schedule / Contract		Revenue Based on Current Factors	Revenue Based on Proposed Factors	Change in Annual Revenue
RS		$ (11,260,367)	$ (9,677,020)	$ 1,583,347
RS-TOD				
	On-Peak	$ (400)	$ (344)	$ 56
	Off-Peak	$ (940)	$ (808)	$ 132
SWS		$ (110,591)	$ (96,560)	$ 14,031
SGS		$ (449,176)	$ (523,846)	$ (74,670)
SGS-LM-TOD				
	On-peak			
	Off-Peak			
SS	Secondary	$ (318,086)	$ (299,049)	$ 19,037
	Primary	$ (37,412)	$ -	$ 37,412
	AF	$ (4,220)	$ (4,016)	$ 204
	Total SS Class			
MGS	Secondary	$ (1,395,532)	$ (1,047,671)	$ 347,861
	Primary	$ (132,606)	$ (161,396)	$ (28,790)
	Subtransmission	$ (9,463)	$ (3,437)	$ 6,026
	Transmission	$ -	$ -	$ -
	AF	$ (2,384)	$ (2,475)	$ (92)
GS-TOD				
	On-Peak Sec.	$ (11,576)	$ (30,638)	$ (19,062)
	Off-Peak Sec	$ (8,346)	$ (5,407)	$ 2,940
	On-Peak Pri.	$ (5,380)	$ -	$ 5,380
	Off-Peak Pri.	$ (4,127)	$ -	$ 4,127
LGS	Secondary	$ (1,093,348)	$ (1,586,183)	$ (492,836)
	Primary	$ (61,721)	$ (433,028)	$ (371,307)
	Subtransmission	$ (32,056)	$ -	$ 32,056
	Transmission	$ -	$ -	
LCP	Secondary	$ (110,873)	$ (91,955)	$ 18,918
	Primary	$ (621,663)	$ (440,197)	$ 181,466
	Subtransmission	$ (937,808)	$ (845,000)	$ 92,808
	Transmission	$ (363,174)	$ (119,717)	$ 243,457
IP	Secondary	$ (81,677)	$ (76,794)	$ 4,883
	Primary	$ (936,066)	$ (754,208)	$ 181,858
	Subtransmission	$ (836,016)	$ (893,338)	$ (57,321)
	Transmission-Other	$ (484,817)	$ (487,629)	$ (2,811)
Special Contract B		$ (158,976)	$ (174,633)	$ (15,657)
Special Contract C			$ -	$ -
	P1	$ (1,528)		
	P2	$ (431)		
	P3	$ (18)		
	P4	$ -		
		$ (1,976)	$ (1,465)	$ 512
Special Contract. E				
	Secondary	$ (3,083)	$ (3,063)	$ 20
	Primary	$ (640)	$ (636)	$ 4
Special Contract I		$ (200,904)	$ (220,680)	$ (19,776)
OL		$ (55,591)	$ (47,683)	$ 7,908
SL		$ (29,360)	$ (28,841)	$ 519
		$ (19,760,355)	**$ (18,057,714)**	**$ 1,702,641**

TRE Exhibit No. 7
Proposed Tariff Schedule

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

CONSTRUCTION/765 kV SURCHARGE
(CS)

A Construction/765kV Surcharge (CS) will be applied to customers' bills rendered during the period from July 1, 2008 through June 30, 2009 under the applicable Schedules as set forth in the table below.

(I)

Schedule	Energy (¢/kWh)	Demand ($/kW)
RS	0.476	
RS-TOD		
On-peak	0.405	
Off-peak	0.030	
SWS	0.484	
SGS	0.326	
SGS-LM-TOD		
On-peak	0.375	
Off-peak	0.049	
SS		
Secondary		1.137
Primary		1.111
AF	0.384	
MGS		
Secondary		0.980
Primary		0.958
Subtransmission		0.954
Transmission		0.932
AF	0.384	
GS-TOD		
On-peak Secondary	0.768	
Off-peak Secondary	0.105	
On-peak Primary	0.808	
Off-peak Primary	0.090	
LGS		
Secondary		1.461
Primary		1.428
Subtransmission		1.422
Transmission		1.389
LCP		
Secondary		1.258
Primary		1.230
Subtransmission		1.224
Transmission		1.196
IP		
Secondary		1.550
Primary		1.514
Subtransmission		1.508
Transmission		1.967
OL	0.000	
SL	0.000	

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(C) Indicates Change, (D) Indicates Decrease, (I) Indicates Increase, (N) Indicates New, (O) Indicates Omission, (T) Indicates Temporary

TRE Exhibit No. 8
Proposed Tariff Schedule

ENEC OVER-RECOVERY AMORTIZATION CREDIT (EOAC)

(C) An ENEC Over-recovery Amortization Credit (EOAC) will be applied to customers' bills rendered during the period from July 1, 2008 through June 30, 2009, under the applicable Schedules as set forth in the table below.

Schedule	Energy ¢/kWh	Demand $/kW
RS	(0.151)	
RS-TOD		
On-peak	(0.151)	
Off-peak	(0.151)	
SWS	(0.099)	
SGS	(0.211)	
SGS-LM-TOD		
On-peak	(0.243)	
Off-peak	(0.032)	
SS		
Secondary	(0.060)	(0.07693)
Primary	(0.000)	(0.00000)
AF	(0.087)	
MGS		
Secondary	(0.049)	(0.05819)
Primary	(0.081)	(0.09186)
Subtransmission	(0.022)	(0.03511)
Transmission	(0.000)	(0.00000)
AF	(0.096)	
GS-TOD		
On-peak Secondary	(0.328)	
Off-peak Secondary	(0.045)	
On-peak Primary	(0.000)	
Off-peak Primary	(0.000)	
LGS		
Secondary	(0.084)	(0.14944)
Primary	(0.211)	(0.34102)
Subtransmission	(0.000)	(0.00000)
Transmission	(0.000)	(0.00000)
LCP		
Secondary	(0.052)	(0.10827)
Primary	(0.045)	(0.06226)
Subtransmission	(0.056)	(0.08654)
Transmission	(0.020)	(0.02700)
IP		
Secondary	(0.059)	(0.12308)
Primary	(0.050)	(0.09638)
Subtransmission	(0.064)	(0.13875)
Transmission	(0.061)	(0.11941)
OL	(0.059)	
SL	(0.093)	

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APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
TESTIMONY
OF
WILLIAM A. ALLEN

DIRECT TESTIMONY OF
WILLIAM A. ALLEN
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 08-______E-GI

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is William A. Allen, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation (AEPSC), as Director of Operating Company Forecasts. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to the subsidiaries of American Electric Power Company, Inc. (AEP), of which Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) are operating subsidiaries. Hereinafter I will refer to these companies either individually as APCo or WPCo or jointly as "the Companies".

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science in Nuclear Engineering from the University of Cincinnati in 1996, and a Master of Business Administration from The Ohio State University in 2004.

I was employed by AEPSC beginning in 1992 as a Coop Engineer in the Nuclear Fuels, Safety and Analysis department and upon completing my degree in 1996 was hired on a permanent basis in the Nuclear Fuel section of the same department. In January 1997, the Nuclear Fuel section became a part of Indiana Michigan Power Company (I&M) due to a corporate restructuring. In 1999, I transferred to the

Business Planning section of the Nuclear Generation Group as a Financial Analyst. In 2000, I transferred back to AEPSC into the Regulatory Pricing and Analysis section as a Regulatory Consultant. In 2003, I transferred into the Corporate Financial Forecasting department as a Senior Financial Analyst. I was named to my current position in April 2007.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS DIRECTOR OF OPERATING COMPANY FORECASTS?

A. I am primarily responsible for the supervision of the financial forecasting and analysis of the AEP System's eleven utilities. In such capacity, I coordinate short- and long-term forecasts for these companies as well as monthly analysis of budget to actual variances. With respect to this filing, I am responsible for the derivation of the sources and disposition of energy analysis for the forecast period.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY OTHER REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony before the Indiana Utility Regulatory Commission (IURC) in I&M's Fuel Adjustment Clause Cases and before the Michigan Public Service Commission (MPSC) in I&M's Power Supply Cost Recovery Plan Cases.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the forecast of the Companies' Expanded Net Energy Cost (ENEC) and Requirement for the twelve-month period ending June 30, 2009. In addition, I have provided projected fixed operation and maintenance costs for the Mountaineer FGD system to Company witness Eads. These projections were used to calculate the individual revenue requirements associated with the proposed Construction Surcharges.

Q. **WERE THE DATA YOU ARE RELYING ON PREPARED BY YOU OR UNDER YOUR SUPERVISION?**

A. Yes. They represent the combined efforts of numerous AEP personnel. I have reviewed the data and believe they are based on valid assumptions and reflect, with reasonable forecasting accuracy, the revenues and costs expected in the future.

Q. **ARE YOU SPONSORING ANY EXHIBITS TO SUPPORT YOUR TESTIMONY IN THIS PROCEEDING?**

A. Yes, I am sponsoring the following exhibits:

- WAA Exhibit No. 2 summarizes the Companies' forecasted ENEC and Requirement for the twelve-month period ending June 30, 2009;
- WAA Exhibit No. 3 is a sources and uses of energy statement for the twelve-month period ending June 30, 2009; and
- WAA Exhibit No. 4 details the projected West Virginia jurisdictional sales for the twelve-month period ending June 30, 2009.

Q. **PLEASE DESCRIBE THE COMPONENTS OF ENEC PROJECTED IN THIS PROCEEDING.**

A. WAA Exhibit No. 2 shows the net cost of all sources of energy incurred in supplying the Companies' internal load plus certain other costs and credits, used in the projection of ENEC in this proceeding. WAA Exhibit No. 2, page 1 of 2, provides the ENEC and WAA Exhibit No. 2, page 2 of 2, provides the corresponding energy requirement. The costs include fossil fuel consumed, purchased power from external sources, AEP

System Pool transactions, and financial settlement of transmission losses, which are offset by revenues from AEP off-system sales. In addition, the ENEC includes certain other revenues associated with transmission service and emission allowance gains, as well as certain other production costs. These costs are primarily for fuel handling and environmental costs such as consumables and the cost of emission allowances.

Q. WAS THE METHODOLOGY USED TO DEVELOP THE PROJECTED ENEC FOR THIS PROCEEDING CONSISTENT WITH THE METHODOLOGY USED FOR FORECASTING ENEC IN THE MOST RECENT RATE PROCEEDING BEFORE THIS COMMISSION?

A. Yes.

Fuel Expense and Fuel Handling (WAA Exhibit No. 2, Page 1, lines 3, 4)

Q. PLEASE DESCRIBE HOW APCO'S PROJECTED COSTS OF FUEL CONSUMED AND FUEL HANDLING WERE CALCULATED.

A. The cost of fossil fuel consumed was based on the generation forecast for each of APCo's fossil generating units as projected for the twelve-month period ending June 30, 2009 by AEPSC's Resource Planning Section utilizing the simulation model PROMOD. PROMOD utilizes the cost of fuel delivered, as supplied by Company witness Rusk, scheduled maintenance outages and forced outage factors to determine the level of generation required to meet load.

The cost of fuel consumed for each of APCo's generating units is equal to the number of tons of coal consumed times the average unit cost of coal in fuel inventory. The average cost of coal is defined by the weighted average cost of coal in inventory at the beginning of the month plus the projected cost of fuel delivered during the month. This calculation is performed for both the cost of coal (account 151 basis) and the cost of fuel handling (account 152 basis).

Purchased Power (WAA Exhibit No. 2, page 1, lines 6, 7, 8)

Q. DEFINE THE COSTS THAT ARE REFLECTED UNDER THE HEADING OF PURCHASED POWER.

A. Purchased Power for APCo reflects the costs associated with planned purchases and APCo's share of other purchases. In this projection, the planned purchases are for energy purchased from Summersville hydro, OVEC and the Camp Grove and Fowler Ridge wind farms. APCo began receiving energy from the Camp Grove wind farm in January 2008 and expects to begin receiving energy from the Fowler Ridge wind farm in January 2009. The other purchases are market purchases primarily resold to third parties. Through economic dispatch, all purchases are assigned to either internal sales or off-system sales based on costs. The cost of Purchased Power incurred to serve the WPCo retail customers will be discussed later in my testimony.

Capacity Settlement (WAA Exhibit No. 2, page 1, line 9)

Q. HOW WERE APCO'S CAPACITY SETTLEMENT CHARGES CALCULATED?

A. APCo's capacity settlement charges were calculated as prescribed under the terms of the FERC-approved AEP Interconnection Agreement (Pool Agreement). The Pool Agreement, which is subject to the jurisdiction of the FERC, regulates the inter-company charges and credits for capacity and energy among the AEP operating companies with generating facilities (Pool members). The Pool members are APCo, Columbus Southern Power Company, Ohio Power Company (OPCo), Kentucky Power Company and I&M.

In accordance with the Pool Agreement, APCo's projected capacity settlement charges were calculated by multiplying its projected capacity deficit by its projected capacity equalization rate. APCo is a deficit member of the Pool and its deficit position was determined by multiplying its Member Load Ratio (MLR) by the total AEP System capacity, and comparing that result to its own capacity. The equalization rate is composed of a fixed investment rate and a fixed operating rate based on the costs of the surplus companies. To the extent there is more than one surplus company then the deficit companies' equalization rate will be based on the weighted rates of the surplus companies.

Q. THE CAPACITY SETTLEMENT CHARGE, ON A TOTAL COMPANY BASIS, IS PROJECTED TO BE $290.4 MILLION, WHICH IS APPROXIMATELY $35 MILLION HIGHER THAN THE PROJECTED COST REFLECTED IN LAST YEAR'S PROCEEDING. PLEASE DESCRIBE THE PRIMARY REASONS FOR THIS INCREASE.

A. The increase in the capacity settlement charge for the twelve-month period ending June 2009 over the forecast included in the 2007 ENEC can be attributed to several factors. The increase reflects a higher capacity equalization rate primarily due to costs for environmental retrofits placed on certain Ohio Power facilities, partially offset by the effects of additional wind capacity at APCo, and a slightly lower MLR. The effect of the investment including environmental retrofits on certain Ohio Power facilities added approximately $46 million (total Company basis) to the charge. The addition of wind capacity reduced APCo's capacity settlement charge by approximately $7 million on a total Company basis. The slightly lower MLR reduced the charge by approximately $4 million (total Company basis).

Off-System Sales Received from Pool (WAA Exhibit No. 2, page 1, lines 10, 11)

Q. DEFINE THE COSTS INCLUDED IN OFF-SYSTEM SALES RECEIVED FROM THE AEP POOL.

A. In accordance with the Pool Agreement, the cost of off-system sales received from the Pool is APCo's MLR share of the total cost incurred by the AEP System, less its MLR share of the APCo-owned generation assigned to off-system sales. This item is APCo's allocated share of the total system cost incurred to make these sales to third parties.

Primary Energy Received (WAA Exhibit No. 2, page 1, line 12)

Q. HOW WAS PRIMARY ENERGY RECEIVED CALCULATED?

A. In accordance with the Pool Agreement, the charges for primary energy received were priced at the average variable cost (fuel + ½ maintenance expense) of the company delivering such energy to APCo.

PJM Costs – Excluding Admin (WAA Exhibit No. 2, page 1, lines 13, 14)

Q. DESCRIBE THE COSTS INCLUDED IN PJM COSTS – EXCLUDING ADMIN.

A. PJM Costs – Excluding Admin include items such as ancillary charges and credits, operating reserve costs, financial transmission rights (FTR) revenues net of congestion costs for off-system sales, and PJM capacity sales.

Q. PJM COSTS – EXCLUDING ADMIN, ON A TOTAL COMPANY BASIS, ARE PROJECTED TO BE $38.0 MILLION, WHICH IS APPROXIMATELY $37 MILLION HIGHER THAN THE PROJECTED COST REFLECTED IN LAST YEAR'S PROCEEDING. PLEASE DESCRIBE THE PRIMARY REASON FOR THIS INCREASE.

A. The increase in PJM Costs – Excluding Admin for the twelve-month period ending June 2009 over the forecast included in the 2007 ENEC is primarily driven by a $31 million increase in net PJM ancillary charges and credits. Net PJM ancillary charges and credits were not explicitly included in prior forecasts. The net of these charges and credits has became more material and is now included in Company forecasts. The forecasted net PJM ancillary charges and credits of $31.0 million are consistent with the $30.6 million incurred during 2007.

Transmission Losses (WAA Exhibit No. 2, page 1, line 15)

Q. DESCRIBE THE COSTS INCLUDED IN TRANSMISSION LOSSES.

A. Transmission Losses include costs and credits associated with I^2R losses (power losses due to resistance) on the transmission system within PJM. Transmission Losses have always been reflected as a component in developing the projected ENEC. Pursuant to FERC orders in Docket No. EL06-55-000, effective June 1, 2007, PJM began separately billing AEP for transmission losses. APCo is allocated its MLR share of losses associated with both its internal load requirements and its share of off-system sales by AEP. The financial settlement of transmission losses increases the AEP system's generation available for off-system sales.

<u>SO_2 and NO_x Expenses (WAA Exhibit No. 2, page 1, line 16)</u>

Q. DESCRIBE THE COSTS INCLUDED IN SO_2 AND NO_X EXPENSES.

A. SO_2 and NO_X Expenses include the costs of consumed emission allowances and consumables used to minimize air emissions. The expenses associated with SO_2 have been estimated pursuant to the methodology established in the FERC-approved AEP Interim Allowance Agreement (IAA). Other expenses for consumables include lime, limestone, urea, polymer and trona.

Q. THE SO_2 AND NO_X EXPENSES, ON A TOTAL COMPANY BASIS, ARE PROJECTED TO BE $40.3 MILLION, WHICH IS APPROXIMATELY $15 MILLION HIGHER THAN THE PROJECTED COST REFLECTED IN LAST YEAR'S PROCEEDING. PLEASE DESCRIBE THE PRIMARY REASON FOR THIS INCREASE.

A. The increase in SO_2 and NO_X expenses for the twelve-month period ending June 2009 over the forecast included in the 2007 ENEC is primarily driven by a $13 million increase in urea expense resulting from increased operation of the Amos 3 and Mountaineer SCRs as well as increased price.

<u>Energy Delivered to Pool for Off-System Sales (WAA Exhibit No. 2, page 1, lines 18, 19)</u>

Q. PLEASE EXPLAIN ENERGY DELIVERED TO POOL FOR OFF-SYSTEM SALES.

A. The credits associated with the energy delivered to the Pool for off-system sales are the cost of APCo's generation or purchases assigned to those sales less APCo's MLR share of its responsibility for such off-system sales.

Primary Energy Delivered (WAA Exhibit No. 2, page 1, line 20)

Q. DESCRIBE HOW PRIMARY ENERGY DELIVERED IS CALCULATED.

A. To the extent APCo has energy available for other member companies during an hour, PROMOD would sell that energy to the Pool. APCo would be reimbursed based on its average variable cost of production (fuel + ½ maintenance expense). No such sales are projected for the twelve-month period ending June 30, 2009.

CSW Tie Revenue (WAA Exhibit No. 2, page 1, line 21)

Q. PLEASE EXPLAIN CSW TIE REVENUE.

A. To the extent that AEP's east zone has available power to sell to AEP's west zone, the power is sold between zones at market prices. The FERC-approved AEP System Integration Agreement governs these inter-zone transactions. When such transactions occur, the AEP east companies generating for the sale are reimbursed for their costs and receive their MLR share of the margin generated by the sale. The value on this line is APCo's share of the projected amount for sales to the west zone of AEP.

Transmission Settlement (WAA Exhibit No.2, page 1, line 22)

Q. EXPLAIN HOW THE TRANSMISSION SETTLEMENT IS CALCULATED.

A. APCo's transmission settlement revenue is calculated in accordance with the FERC-approved AEP Transmission Equalization Agreement (TEA). The TEA regulates the inter-company charges and credits for high-voltage transmission investment among the same AEP operating companies which are parties to the Pool Agreement. In accordance with the TEA, APCo's transmission revenue is calculated by multiplying its transmission investment surplus by its carrying charge rate. APCo is projected to be a surplus member of the transmission pool and its surplus position is determined by multiplying the MLR by the total system investment, and comparing that result to its own investment.

<u>Third Party Transmission Revenue (WAA Exhibit No. 2, page 1, line 23)</u>

Q. EXPLAIN HOW THIRD PARTY TRANSMISSION REVENUE IS PROJECTED.

A. Third party transmission revenue consists of fees paid to the AEP east companies for use of their transmission lines. The AEP east companies are reimbursed in accordance with the FERC-approved OATT (Open Access Transmission Tariff) and APCo shares in these reimbursements based on its MLR.

<u>Off-System Sales Revenue (WAA Exhibit No. 2, page 1, lines 24, 25)</u>

Q. DESCRIBE HOW REVENUES FROM OFF-SYSTEM SALES WERE DETERMINED.

A. Revenues from the various components of off-system sales were developed on a System basis with APCo receiving credit for its MLR share of such revenue. Specifically, the revenues were based on the kWh sales levels included in the AEPSC Load Forecast. Revenues related to known off-system sales were developed in accordance with the terms of the specific existing agreements governing those known off-system sales. The remaining sales are assumed sales with unknown parties. The revenues for such sales assume the recovery of costs incurred to make the sale along with a forecast of net realization or margin.

<u>FTR Revenue Net of Congestion Costs - LSE (WAA Exhibit No 2, page 1, line 26)</u>

Q. PLEASE EXPLAIN FTR REVENUE NET OF CONGESTION COSTS – LOAD SERVING ENTITY (LSE).

A. Within the PJM RTO, members receive FTR revenues and incur congestion costs, which may or may not offset each other. FTRs are financial instruments, which entitle the holder to receive compensation for certain congestion-related transmission charges that arise when the grid is congested. APCo's share of congestion costs is forecasted to exceed its FTR revenues in the twelve-month period ending June 30, 2009 by approximately $1.3 million on a total Company basis.

Q. THE FTR REVENUE NET OF CONGESTION COSTS FOR THE LSE, ON A TOTAL COMPANY BASIS, IS PROJECTED TO BE A NEGATIVE $1.3 MILLION, WHICH IS APPROXIMATELY $26 MILLION HIGHER THAN THE PROJECTED COST REFLECTED IN LAST YEAR'S PROCEEDING. PLEASE DESCRIBE THE PRIMARY REASON FOR THIS INCREASE.

A. The increase in FTR revenue net of congestion costs for the LSE for the twelve-month period ending June 2009 over the forecast included in the 2007 ENEC is primarily driven by a more precise allocation of FTR revenues between off-system sales and the LSE. This results in more FTR revenues being included in PJM Costs – Excluding Admin than in the previous forecast.

<u>Gain/(Loss) on Sale of Allowances (WAA Exhibit No. 2, page 1, line 27)</u>

Q. PLEASE EXPLAIN WHAT IS INCLUDED IN GAIN/(LOSS) ON SALE OF ALLOWANCES.

A. Gain/(Loss) on Sale of Allowances includes the proceeds from the sale of withheld allowances in the annual EPA auction, gains associated with the reallocation of allowances related to the Gavin Scrubber and gains associated with market sales of allowances. The provisions of the previously mentioned FERC-approved IAA also govern these allowance transactions.

Q. WHAT ARE THE PROJECTED ENEC AMOUNTS FOR THE TWELVE-MONTH PERIOD ENDING JUNE 30, 2009?

A. As shown on WAA Exhibit No. 2, APCo's projected ENEC for the twelve-month period ending June 30, 2009 is $995.7 million and 41,239 GWh. I have provided this information to Company witness Ferguson for his use.

Q. PLEASE DESCRIBE HOW THE COST TO SERVE THE WPCO LOAD HAS BEEN REFLECTED IN THE DERIVATION OF THE ENEC COST PROJECTIONS.

A. The wholesale power costs incurred to serve the WPCo load have been included in the derivation of Companies' ENEC as memo items on lines 34 and 35 of WAA Exhibit No. 2, page 1. These amounts reflect the costs expected to be incurred by WPCo to serve its customers based upon new rates developed by OPCo. It is estimated that the new rates would increase WPCo's costs by $18 million for the twelve-month period ending June 30, 2009. The energy requirement to serve WPCo customers is shown on WAA Exhibit No. 2, page 2.

Q. HAVE YOU PROVIDED COMPANY WITNESS EADS WITH FORECASTED DATA ON THE OPERATION OF THE MOUNTAINEER FGD SYSTEM?

A. Yes. The projected fixed O&M cost of $11.8 million associated with operation of the Mountaineer FGD system for the twelve-month period ending June 30, 2009 was provided to Company witness Eads for his use.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPALACHIAN POWER COMPANY
AND WHEELING POWER COMPANY
Expanded Net Energy Cost and Requirement
Twelve Months Ending June 30, 2009
($000)

WAA Exhibit No. 2
Page 1 of 2

Line No.		Ending 6/30/2009
1	Expanded Net Energy Cost and Requirement ($000)	
2	Fossil Generation (Energy)	
3	Fuel Expense	646,600
4	Fuel Handling	15,895
5	Plus:	
6	Purchased Power (Demand)	52,071
7	Purchased Power (Energy)	190,703
8	Purchased Power - Wind (Energy)	23,582
9	Capacity Settlement (Demand)	290,379
10	Off-System Sales Received from Pool (Demand)	-
11	Off-System Sales Received from Pool (Energy)	237,879
12	Primary Energy Received (Energy)	230,351
13	PJM Costs - Excluding Admin (Demand)	(14,085)
14	PJM Costs - Excluding Admin (Energy)	52,105
15	Transmission Losses (Energy)	90,567
16	SO2 and NOx Expenses (Energy)	40,276
17	Less:	
18	Energy Delivered to Pool for Off-System Sales (Demand)	-
19	Energy Delivered to Pool for Off-System Sales (Energy)	209,562
20	Primary Energy Delivered (Energy)	-
21	CSW Tie Revenue (Energy)	28,476
22	Transmission Settlement (Demand)	29,348
23	3rd Party Transmission Revenue (Demand)	27,818
24	Off-System Sales Revenue (Demand)	-
25	Off-System Sales Revenue (Energy)	540,510
26	FTR Revenue Net of Congestion Costs - LSE (Demand)	(1,282)
27	Gain/(Loss) on Sale of Allowances (Energy)	26,161
28	Total Expanded Net Energy Cost ($000)	995,730
29	Expanded Net Energy Cost and Requirement (Demand & Energy)	
30	Total Demand	272,481
31	Total Energy	723,249
32	Total Expanded Net Energy Cost ($000)	995,730
33	Memo Items:	
34	Wheeling Purchases (Demand)	38,228
35	Wheeling Purchases (Energy)	59,795

APPALACHIAN POWER COMPANY
AND WHEELING POWER COMPANY
Expanded Net Energy Cost and Requirement
Twelve Months Ending June 30, 2009
(GWh)

Line No.		Ending 6/30/2009
1	Expanded Net Energy Cost and Requirement (GWh)	
2	Fossil Generation	32,203
3	Hydro Generation	578
4	Total Generation	32,781
5	Plus:	
6	Purchased Power	5,579
7	Purchased Power - Wind	445
8	Off-System Sales Received from Pool	8,520
9	Primary Energy Received	11,921
10	Other	-
11	Less:	
12	Energy Delivered to Pool for Off-System Sales	6,441
13	Primary Energy Delivered	-
14	Off-System Sales	11,566
14	Expanded Net Energy Cost and Requirement (GWh)	41,239
15	Memo Item:	
16	Wheeling Purchases	2,311

WAA Exhibit No. 3

APPALACHIAN POWER COMPANY
Sources and Uses of Energy
Twelve Months Ending June 30, 2009
(GWh)

Line No.	Sources of Energy	Ending 6/30/2009
1	Steam Generation by Plant:	
2	Amos	11,863
3	Ceredo	9
4	Clinch River	4,055
5	Glen Lyn	1,623
6	Kanawha River	2,640
7	Mountaineer	10,663
8	Philip Sporn	1,350
9	Total Steam Generation	32,203
10	Hydro Generation by Type:	
11	Conventional Hydro	717
12	Pump Storage	(139)
13	Total Hydro Generation	578
14	Total Generation	32,781
15	Purchased Power:	
16	Purchased Power	5,579
17	Purchased Power - Wind	445
18	Energy Received from Pool	20,441
19	Other	-
20	Total Purchased Power	26,465
21	Total Sources of Energy	59,246
	Uses of Energy	
22	Sales to Ultimate Customers:	
23	Residential	12,796
24	Commercial	7,194
25	Industrial	14,243
26	All Other Ultimates	835
27	Total Sales to Ultimates	35,068
28	Associated Companies	2,850
29	Municipals and Cooperatives	1,163
30	Losses	2,158
31	Total Internal	41,239
32	Energy Delivered to Pool	6,441
33	Off-System Sales	11,566
34	Total Uses of Energy	59,246

WAA Exhibit No. 4

APPALACHIAN POWER COMPANY
AND WHEELING POWER COMPANY
Projected Total Ultimate Sales - State of West Virginia
Twelve Months Ending June 30, 2009
(GWh)

Line No.		Ending 6/30/2009
1	Sales to Ultimate Customers	
2	Residential	5,955
3	Commercial	3,779
4	Industrial	8,475
5	Other Ultimates	102
6	Total Ultimate Sales	18,311
7	Memo Items:	
8	Wheeling Residential	444
9	Wheeling Commercial	433
10	Wheeling Industrial	1,373
11	Wheeling Other Ultimates	6
12	Total Wheeling Ultimate Sales	2,256

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
TESTIMONY
OF
JASON T. RUSK

DIRECT TESTIMONY OF
JASON T. RUSK
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 08-_______E-GI

Q. **PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.**

A. My name is Jason T. Rusk. I am employed by the American Electric Power Service Corporation ("AEPSC"), a subsidiary of American Electric Power Company, Inc. ("AEP"), in the Fuel, Emissions & Logistics Group as Manager, Eastern Fuel Procurement. My business address is 155 West Nationwide Boulevard, Suite 500, Columbus, Ohio 43215.

Q. **PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

A. I graduated from Miami University in 1978 with a Bachelor of Science degree in Finance and Economics. I also earned a Master's in Business Administration degree from the University of Cincinnati in 1981 with concentration in Finance and Marketing.

Q. **PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.**

A. I joined AEP in 1981 as an Internal Auditor and transferred to the coal procurement group in 1983 as an Analyst performing economic studies and drafting language for prospective long-term coal contracts. I transferred into the Logistics Group in 1994 to work on numerous special projects, and returned to the Coal Procurement group in 1996.

I left AEP in December 2002, and rejoined AEP in my current position in the Fuel, Emissions & Logistics Group as Manager, Eastern Fuel Procurement in June 2004.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS MANAGER OF FUEL PROCUREMENT FOR AEPSC?

A. I am responsible for the procurement of fuel for a portion of AEP's eastern generating fleet, which includes power plants owned and operated by Appalachian Power Company ("APCo"), Indiana Michigan Power Company and Kentucky Power Company. I am an agent for Ohio Valley Electric Corporation and Indiana Kentucky Electric Corporation.

PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to:

(1) Describe the coal delivery forecast for the 12 months ending on June 30, 2009,

(2) Describe APCo's portfolio of coal supply agreements, and

(3) Discuss APCo's fuel purchasing strategy.

COAL DELIVERY FORECAST

Q. HAS AEP PREPARED A FORECAST OF DELIVERED COAL PRICES FOR THE APPALACHIAN POWER PLANTS FOR THE PERIOD OF JULY 2008 THROUGH JUNE 2009?

A. Yes. The forecasted data for this period, prepared as of December 2007, was provided for use by Company witness Allen by coal purchase type (Committed, Non-committed and Total) and price per ton (FOB mine, transportation and total delivered price), along with the total weighted average forecasted price of coal delivered to

Appalachian's generating stations, on a cents per million BTU basis, for the period July 2008 to June 2009.

Q. IN PREPARING THE FORECAST OF DELIVERED COAL, HAS THE COMPANY CHANGED OR AMENDED THE OVERALL PARAMETERS THAT IT HAS HISTORICALLY USED IN THE DEVELOPMENT OF COAL DELIVERY FORECASTS THAT HAVE BEEN PREVIOUSLY SUBMITTED TO THIS COMMISSION?

A. No. The methodology utilized in this forecast is consistent with the methodology that has been used by the Company and presented to this Commission in previous proceedings.

APCO'S PORTFOLIO OF COAL SUPPLY AGREEMENTS

Q. PLEASE DESCRIBE APCO'S *PORTFOLIO* OF COAL SUPPLY AGREEMENTS.

A. APCo currently has seven long-term contracts that will be in effect during the twelve-month period ending on June 30, 2009. These contracts have various expiration dates, tonnages, and prices. Summary information regarding these agreements, primarily as it relates to the forecast period, is presented below and in JTR Exhibit No. 2. I will discuss APCo's fuel purchasing strategy relative to all agreements, later in this testimony.

1. AMERICAN ENERGY CORPORATION - The American Energy Corporation ("American") contract became effective on December 1, 2006. Barge deliveries under this contract will be made to the Amos and/or

Mountaineer plants during the forecast period. An escalated price, based on government indices, is used in this agreement.

2. ARCH COAL SALES COMPANY, INC. – The Arch Coal Sales Company, Inc. ("Arch") contract began on March 1, 2005. The coal will be delivered by rail to the Amos plant during the forecast period. An escalated price, based on government indices, is used in this agreement.

3. CENTRAL WEST VIRGINIA ENERGY COMPANY - APCo's contract with Central West Virginia Energy Company ("CWVE") began July 1, 1991. The coal will be delivered by rail and/or by barge to the Amos, Mountaineer, Glen Lyn and/or Sporn plants during the forecast period. An escalated price, based on government indices, is used in this agreement.

4. DYNAMIC ENERGY, INC. – APCo's contract with Dynamic Energy, Inc. ("Dynamic") became effective on September 1, 2005. The coal will be delivered by rail to the Glen Lyn plant at a negotiated fixed price during a portion of the forecast period.

5. GATLING, LLC – The Gatling, LLC ("Gatling") contract became effective on December 22, 2005. Under this agreement, coal will be delivered by conveyor belt to the Mountaineer plant. Fixed prices per ton have been established for the forecast period.

6. MASSEY COAL SALES CO., INC. – The first Massey Coal Sales Co., Inc. contract began July 1, 2003. Coal will be delivered to the Amos, Mountaineer and/or Sporn plants by rail and/or by barge under this agreement. A fixed price per ton has been established for the forecast period.

7. MASSEY COAL SALES CO., INC. – The second Massey Coal Sales Co., Inc. contract became effective April 10, 2006. The contract provides for coal to be delivered by barge to the Mountaineer plant. A fixed price per ton has been established for the forecast period

Q. WHY ARE THERE FEWER LONG-TERM COAL SUPPLY AGREEMENTS SHOWN ABOVE THAN LISTED IN LAST YEAR'S ENEC FILING?

A. Three of the agreements reported in the 2007 ENEC are no longer in effect. The Progress Fuel Corporation and Panther LLC contracts expired on December 31, 2007. Although the COALSALES agreement provided for an extension of the term beyond December 31, 2007, the seller elected not to exercise that option.

Q. ARE THERE OTHER LONG-TERM COAL SUPPLY AGREEMENTS IN DEVELOPMENT THAT COULD AFFECT COAL PRICES AND DELIVERIES DURING THE FORECAST PERIOD?

A. Yes. A number of agreements are currently being finalized that are expected to result in long-term coal deliveries during the forecast period at higher prices than those reflected in the December 2007 forecast used in this proceeding.

Q. IN ADDITION TO ITS LONG-TERM CONTRACTS, DOES APCO HAVE ANY OTHER TERM COAL SUPPLY ARRANGEMENTS?

A. Yes. APCo has taken advantage of opportunities to extend term purchase orders at favorable pricing. APCo currently has one purchase order with a term greater than one year. Such agreement with Delta Coals & Red River Coal Company was previously extended beyond its original term to include a portion of the forecast period.

FUEL PURCHASING STRATEGY

Q. PLEASE DESCRIBE APCO'S COAL PURCHASING STRATEGY.

A. APCo's purchasing strategy for coal is based on continuous market monitoring and evaluation along with periodic competitive offers. The consumption needs are determined from a system-based approach that predicts said needs on a plant-by-plant basis. Coal supply offers are solicited from active suppliers by specifying the quality and logistical parameters sought for each plant. From the offers received, APCo then makes its selection, if reasonable, of the coals needed to meet its requirements based primarily on price and coal quality considerations.

Q. HAVE THERE BEEN ANY RECENT CHANGES IN COAL MARKET CONDITIONS THAT HAVE SIGNIFICANTLY AFFECTED OR WILL SIGNIFICANTLY AFFECT APCO'S COAL PROCUREMENT PRACTICES?

A. Yes. The coal industry has experienced a number of situations that have impacted current coal deliveries and prices. Some of these events include: reductions in and delays in "new" mine operating permits, high domestic and international demand for the types of coal required for APCo's coal generating plants, a shortage of trained mining personnel and environmental constraints. As a result, higher delivered coal costs are projected for 2008 and 2009.

Q. HAS APCO PARTICIPATED IN ANY RECENT COAL SOLICITATIONS?

A. Yes. The Company has participated in four coal solicitations for high fusion coals of low and high level sulfur since January 2007. In 2007, the first solicitation was on January 19, 2007, the second on April 23, 2007, and the third one on August 6, 2007.

The first solicitation indicated that the company is interested in one or more agreements with a minimum of 10,000 tons of coal per month with deliveries by rail or barge commencing as early as January 1, 2008 for a minimum term of one year and up to three years. The second solicitation invited tenders of one or more agreements of 10,000 tons of coal per month with deliveries by rail or barge commencing as early as January 1, 2008 for a term of one year, three years and up to five years. The third solicitation invited tenders of one or more agreements of 25,000 tons of coal per month with deliveries by rail or barge commencing as early as January 1, 2008. Additionally, the third solicitation also invited tenders of one or more agreements of a maximum of 1,000,000 tons per year for delivery by rail or barge commencing in 2010.

The Company has participated in one solicitation to date in 2008. The solicitation invites tenders for one or more spot agreements, each for the supply of a minimum of 5,000 tons of coal per month, delivered by rail or barge, commencing in April 2008 as available. Additionally, the same solicitation also invites tenders for one or more term agreements, each for the supply of a minimum of 10,000 tons of coal per month, delivered by rail or barge, commencing in 2009.

Q. **PLEASE DISCUSS HOW APCO HAS ADAPTED ITS FUEL PURCHASING STRATEGY TO ADDRESS CURRENT CIRCUMSTANCES AND MAINTAIN FUEL FLEXIBILITY?**

A. APCo has participated in a limited number of coal hedges that allow the Company to take advantage of attractively priced coal supplies for the benefit of its customers. Furthermore, APCo will mitigate excess fuel supplies as needed in order to maximize operational flexibility. The Company will continue to participate in coal solicitations and invoke its option rights under existing agreements for additional tonnage when it is economically viable.

Q. WHAT IS THE STATUS OF THESE HEDGES ACQUIRED IN 2007?

A. These hedges have been liquidated by the Company over a period of time. Margins from these hedge transactions are being used as a credit against the cost of fuel for APCo's customers in 2008. The hedges served to lock in an attractive price of coal against potential volatility.

Q. HAS APCO MADE USE OF THE TEMPORARY AND LIMITED EXEMPTION WHICH THE COMMISSION GRANTED IT IN CASE 07-0248-E-GI TO ENGAGE IN CERTAIN SPECIFIED FUEL TRANSACTIONS WITHOUT OBTAINING PRIOR APPROVAL UNDER <u>W.VA. CODE</u> §24-2-12?

A. Yes. Since the issuance of the Commission's Order on June 22, 2007, there has been no need for APCo to engage in any transactions with affiliates. However, APCo has engaged in a number of coal hedges and a number of exempted purchase-and-sale transactions. These are all detailed in the report on exempted transactions which is being filed separately as an informational filing (under seal, accompanied by a motion for protective treatment) as part of the Companies' 2008 ENEC proceeding. To the extent that the Commission or any party has questions about these transactions, I am prepared to address them, subject to such protective measures as the Commission sees fit to impose. As the detail in the Report demonstrates, the flexibility allowed by the

Commission's exemption has been useful and beneficial to APCo and the Companies' ratepayers in pursuing an effective fuel procurement strategy.

Q. PLEASE PROVIDE A SUMMARY OF APCO'S ANTICIPATED SOURCES OF NATURAL GAS SUPPLY AND COSTS.

A. APCo's only natural gas fired facility is the Ceredo Power Plant (Ceredo). Ceredo's day-to-day needs for natural gas are generally unpredictable and will be purchased on a day-ahead and intra-day basis as needed for peaking requirements. Natural gas purchases will be competitively bid and primarily obtained in the spot market with prices on a daily index or a daily fixed price. APCo has arranged for interruptible transportation service from various inter-state pipelines, which will provide flexible supplies from multiple production areas. APCo has also arranged for firm transportation with Mountaineer Gas Company, the local distribution company that will move the needed supplies from the inter-state pipeline to the Ceredo facility.

Q. IS RISK ASSESSMENT STILL AN IMPORTANT FACTOR IN COAL PURCHASING DECISIONS?

A. Yes. APCo places great importance on a vendor's financial status, ability to deliver, and past performance when evaluating its decision to do business with that supplier. Purchases from reliable vendors serve to enhance APCo's security of supply.

Q. DO YOU HAVE AN OPINION REGARDING THE REASONABLENESS OF APCO'S PROJECTED FUEL COSTS?

A. Yes. APCo has and continues to aggressively pursue and manage its fuel supplies and transportation costs to provide reliable supplies at reasonable costs. In my opinion, the projected fuel costs are reasonable.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPALACHIAN POWER COMPANY
SUMMARY OF COAL SUPPLY AGREEMENTS
CURRENT TERMS

TESTIMONY REFERENCE	AGREEMENT NUMBER	CONTRACT	DELIVERY STARTING DATE	PLANT(S)	TRANS. OPTIONS	SPECIFICATIONS BTU	MOISTURE	ASH	#SO2
1	02-10-06-901	American Energy Corporation	1/1/2008	Amos, Mountaineer	Barge/ Rail	12,500	7.0%	9.25%	< 7.4
2	02-40-05-901	Arch Coal Sales Company, Inc.	3/1/2005	Amos	Rail	≥ 12,000	≤ 8.0%	≤ 13.0%	≤ 1.35
3	02-10-90-910	Central West Virginia Energy Co.	7/1/1991	Amos, Sporn Mountaineer	Barge/ Rail	12,000 12,000	7.0% 7.0%	12.5% 12.5%	≤ 1.2 "A" ≤ 1.4 "B"
4	02-80-05-900	Dynamic Energy, Inc.	9/1/2005	Glen Lyn	Rail	12,500	7.5%	12.0%	1.6
5	02-10-04-904	Gatling, LLC	1/1/2007	Mountaineer	Belt	12,050	7.0%	10.0%	4.5
6	02-40-03-900	Massey Coal Sales Co., Inc.	7/1/2003	Amos Amos, Sporn	Rail Barge	12,000 11,900	≤ 8.0% ≤ 8.0%	≤ 13.0% ≤ 13.0%	< 1.5 < 1.85
7	02-10-06-900	Massey Coal Sales Co., Inc.	10/1/2006	Mountaineer	Barge	12,000	≤ 8.0%	≤ 12.0%	< 6.5

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
TESTIMONY
OF
STEVEN H. FERGUSON

DIRECT TESTIMONY OF STEVEN H. FERGUSON ON BEHALF OF APPALACHIAN POWER COMPANY AND WHEELING POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA IN CASE NO. 08-____-E-GI

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Steven H. Ferguson. My business address is 707 Virginia Street, East, Charleston, West Virginia. I am employed by Appalachian Power Company ("APCo") as a Principal Regulatory Consultant – Regulatory Services for West Virginia.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated with a Bachelor of Science Degree in Mathematics from Radford College, Radford Virginia, in 1979. In 2007, I attended the American Electric Power Strategic Leadership Program at The Ohio State University's Fisher College of Business.

I joined APCo in May of 1979 as an Engineering Technician in the Operations Department in Roanoke Virginia, where I was responsible for statistical reporting of load research data. In 1981, I was promoted to Statistical Analyst in the Allocation Section of the Rate Department. In 1985, I was promoted to an Allocation Analyst where I was responsible for completing the Company's jurisdictional allocation studies and cost of service studies. Following the reorganization of the AEP system in 1996, I moved to Charleston, West Virginia as a Rate Analyst I. In January of 1998, I was promoted to the position of Senior Rate Analyst. In April 2006, I was promoted to my current position.

Q. WHAT ARE YOUR DUTIES AS A PRINCIPAL REGULATORY CONSULTANT?

A. My current duties include performing various rate and regulatory activities for APCo and Wheeling Power Company ("WPCo") in West Virginia including the preparation of Expanded Net Energy Cost ("ENEC") filings.

Q. **FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am testifying on behalf of both APCo and WPCo. I shall refer to these entities individually as APCo or WPCo, or jointly as the "Companies."

Q. **HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AS A WITNESS BEFORE ANY REGULATORY COMMISSION?**

A. Yes. I presented testimony on behalf of APCo before the Public Service Commission of West Virginia in Case No. 96-0458-E-GI and Case No. 99-0409-E-GI. I have also presented testimony for APCo and WPCo in Case No. 05-1278-E-PC-PW-42T and Case No. 07-0248-E-GI.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to: 1) support the forecast and actual jurisdictional and class demand and energy allocation factors used in the development of the proposed ENEC factors; 2) provide detailed calculations of the ENEC recovery position for the period January 2007 through December 2007; 3) support the development of the proposed ENEC rate components to be incorporated into the rates to be approved in this case; and 4) provide P.S.C. W. VA. Tariff No. 12 (Appalachian Power Company) and P.S.C. W. VA. Tariff No. 17 (Wheeling Power Company) tariff sheets incorporating the Companies' proposed ENEC rates.

In addition to the ENEC, I will address the cost recovery provisions approved in the Commission's April 18, 2007 order in Case No. 06-0828-EW-SC, with respect to APCo's acquisition of assets and assumption of service responsibilities of the electric operations of the four Musser Companies providing service in McDowell County, West Virginia.

I will also discuss the treatment of the Companies' reliability expenditures as provided in the Commission's order in Case No. 05-1278-E-PC-PW-42T (2005 Base Case).

ENEC

Q. FOR WHICH TIME PERIOD HAVE YOU PREPARED FORECAST JURISDICTIONAL AND CLASS DEMAND AND ENERGY ALLOCATION FACTORS?

A. The forecast jurisdictional and class demand and energy allocation factors have been prepared for the twelve-month period ending June 2009.

Q. IS THE METHODOLOGY USED IN DETERMINING THE FORECAST JURISDICTIONAL AND CLASS DEMAND AND ENERGY ALLOCATION FACTORS THE SAME AS THAT USED IN THE COMPANIES' LAST ENEC FILING?

A. Yes. The determination of these allocation factors is based upon the demand and energy forecasts provided by the Resource Planning & Operations Analysis Section of the American Electric Power Service Corporation and employs the same methodology utilized by the Companies in Case No. 07-0248-E-GI (2007 ENEC Case).

Q. PLEASE EXPLAIN THE DEVELOPMENT OF APCO'S JURISDICTIONAL DEMAND AND ENERGY ALLOCATION FACTORS.

A. The jurisdictional allocation factors for APCo are based on the forecast of demand and energy requirements for the twelve months ending June 30, 2009, as shown in SHF Exhibit No. 2. This forecast projects sales to ultimate and wholesale customer groups in West Virginia, Virginia and Tennessee and an aggregation of system losses. SHF Exhibit No. 3 provides the calculation of the jurisdictional demand and energy factors used to allocate APCo's projected ENEC-related components to the West Virginia jurisdiction.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE PROJECTED CUSTOMER DEMAND AND ENERGY ALLOCATION FACTORS.

A. The projected customer demand and energy allocation factors were developed through a process that apportions the forecast West Virginia jurisdictional demand and energy requirements among the customer classes based primarily on actual demand and energy data for a historic twelve-month period, in this case the year ended December 31, 2007. SHF Exhibit No. 4 provides detail of the forecast customer class demand and energy allocation factors.

Q. IS THE METHODOLOGY FOR DEVELOPING THE JURISDICTIONAL AND CLASS ALLOCATION FACTORS CONSISTENT WITH THE PROCEDURES USED IN PREVIOUS ENEC PROCEEDINGS?

A. Yes. The same methodology was used in the development of the ENEC rates that were put into effect on July 1, 2007.

Q. PLEASE SUMMARIZE THE ACTUAL ENEC RECOVERY POSITION FOR THE PERIOD JANUARY 2007 THROUGH DECEMBER 2007.

A. I have prepared SHF Exhibit No. 5 to summarize the ENEC recovery position on an actual basis for the period January 2007 through December 2007. As shown in SHF Exhibit No. 5, APCo has recorded an under-recovery of $454,205, as related to the Companies' ENEC recovery position.

Q. **WHAT IS THE PRIMARY OBJECTIVE IN THE DEVELOPMENT OF THE PROPOSED ENEC FACTORS?**

A. The primary objective in the development of the ENEC factors is to recover the projected jurisdictional ENEC related costs for the twelve-month period ending June 30, 2009, as allocated to each customer class, net of any prior period under-recovery responsibility among the classes. SHF Exhibit No. 6 provides the forecast class energy and demand ENEC related cost responsibilities including recognition of the prior period under-recovery.

Q. **PLEASE GENERALLY DESCRIBE THE METHODOLOGY USED TO DEVELOP THE ENEC FACTORS INCLUDED IN THE COMPANIES' PROPOSED RATES.**

A. The development of the proposed ENEC factors began with a forecast of the annual components of costs and revenues to be included in the ENEC. In this case, the forecast period is the twelve months ending June 30, 2009. To the extent the ENEC components are associated with multiple jurisdictions, as is the case for APCo, they are allocated to West Virginia and then to the customer classes, or individual customers, based on appropriate demand and energy relationships. Once the ENEC components have been assigned to a class of customer, forecast billing determinants for each customer class were used to arrive at the individual demand or energy factors appropriate to recover each class's ENEC.

Q. HAVE THE COSTS AND REVENUES RELATED TO WPCO BEEN INCLUDED IN THE ENEC CALCULATION?

A. Yes. Consistent with the order in the 2005 Base Case, the ENEC factors were brought into parity for both Companies. Accordingly, forecast annual components of WPCo's costs of purchased power and sales have been reflected in the development of the proposed ENEC factors.

Q. IS THERE ANY PRIOR-PERIOD OVER/UNDER-RECOVERY COMPONENT REFLECTED IN THE PROPOSED ENEC FACTORS?

A. Yes. As in prior ENEC proceedings, the new ENEC factors include both the "in-period" rate components related to projected future costs, and a "prior period" component. The "prior period" rate component in the proceeding provides for the recovery of actual ENEC balance as of December 31, 2007.

Q. HAVE YOU PREPARED AN EXHIBIT SUMMARIZING THE ENEC FACTORS WHICH THE COMPANIES PROPOSE TO BECOME EFFECTIVE JULY 1, 2008?

A. Yes. SHF Exhibit No. 7 reflects the ENEC rates the Companies propose to be incorporated in the Companies' tariffs to allow for the recovery of both rate components. The ENEC factors shown in SHF Exhibit No. 7 would provide for the recovery of $140,018,306 in additional revenues and reflects $135,236,306 in ENEC revenues and $4,782,000 in reliability expenditures revenues which I will discussed later in my testimony.

Q. PLEASE DESCRIBE HOW THE $135,236,306 WAS DETERMINED.

A. It was determined by comparing the ENEC revenue received using the forecast period billing determinants under the previously approved ENEC factors with revenues that would be received from the proposed factors when applied to the forecast period billing determinants. SHF Exhibit No. 8 calculates the proposed revenues to be used to develop the rates needed to produce the additional $135,236,306.

Q. HAVE YOU PREPARED REVISED TARIFF SHEETS INCORPORATING THE COMPANIES' PROPOSED ENEC FACTORS AS PROVIDED IN SHF EXHIBIT NO. 9?

A. Yes. SHF Exhibit No. 9 contains proposed revisions of the applicable tariff schedules of the Companies' P.S.C. West Virginia Tariff No. 12 (Appalachian Power Company) and P.S.C. West Virginia Tariff No. 17 (Wheeling Power Company). These revised Tariffs No. 12 and 17 are designed to become effective with service rendered on and after July 1, 2008.

MUSSER COMPANIES SERVICE ACQUISITION

Q. PLEASE ADDRESS THE COMPANIES' COST RECOVERY POSITION AS IT RELATES TO APCO TAKING OVER THE FACILITIES AND SERVICE OBLIGATION AS ORDERED IN CASE NO. 06-0828-EW-SC.

A. As shown in SHF Exhibit No. 10, APCo's expenditures through December 31, 2007 to upgrade and repair the facilities of the former McDowell County Musser Companies were $1,393,108.33 for O&M expenses, $83,333.33 for amortization expenses of the purchase price and $20,267.87 for the return/taxes required on the additional net new investment incurred for upgrades and repairs, for a total of $1,496,709.53. The revenues collected through the approved surcharge for the same period were $1,037,950.95.

Q. HAS APCO ESTIMATED THE EXPENDITURES THAT WILL BE REQUIRED TO CONTINUE THE UPGRADES AND REPAIRS OF THE FORMER MCDOWELL COUNTY MUSSER COMPANIES?

A. Yes. SHF Exhibit No. 11, shows the level of O&M expenses and capital expenditures projected over the coming year in order to continue the upgrades and repairs to the former facilities of the McDowell County Musser Companies. As shown on this exhibit, APCo expects to incur O&M expenditures of $1,006,500 and capital expenditures of $2,080,000.

Q. WHAT IS THE BASIS FOR THE PROPOSED EXPENDITURES INCLUDED IN YOUR EXHIBIT?

A. APCo personnel have projected these expenditures on the basis of work already performed and the projected work to complete the upgrades and repairs necessary to bring the facilities up to the standards APCo deems appropriate.

Q. HAS APCO BEEN TRACKING THE REVENUE COLLECTED THROUGH THE ADDITIONAL RETAIL SALES SURCHARGE TARIFF AND THE ACTUAL COST INCURRED PURSUANT TO THE COMMISSION'S ORDER?

A. Yes. APCo is tracking both the revenues collected and the actual cost incurred with the understanding that any over or under recoveries of the costs currently being deferred will be reconciled in the next base rate case.

Q. HAVE YOU DEVELOPED NEW ESTIMATES OF THE ANNUAL REVENUE REQUIREMENTS NEEDED FOR SYSTEM UPGRADES AND REPAIRS OF THE FORMER MUSSER COMPANIES TO BE RECOVERED IN THE CURRENT ENEC COST RECOVERY PERIOD?

A. Yes. SHF Exhibit No. 12 provides the projected O&M expenses APCo estimates it will incur and expects to recover during the twelve months ending June 30, 2009. In addition, this exhibit also provides projections of the estimated capital investment and related required return along with the tax and depreciation expense.

Q. HAVE YOU CALCULATED A PROPOSED SURCHARGE FACTOR TO RECOVER THE SYSTEM UPGRADES AND REPAIRS REVENUE REQUIREMENT?

A. Yes. As shown on SHF Exhibit No. 13, I have calculated a surcharge rate of $0.000148 by dividing the revenue requirement for the upgrades and repairs by the projections of ENEC kwh sales for customers served under the RS, SGS, SS, SWS, MGS, OL and SL rate schedules.

RELIABILITY EXPENDITURES

Q. PLEASE EXPLAIN THE TREATMENT OF THE RELIABILITY EXPENDITURES APPROVED IN THE 2005 BASE CASE?

A. The Commission's order approving in the Joint Stipulation reached in the 2005 Base Case, provided that should the Companies expend an annual average of $18,660,000 in calendar years 2007, 2008 and 2009, for measures designed to maintain and enhance reliability of service (i.e. right-of-way vegetation management and asset management activities), and should the Companies fail to earn a rate of return on common equity ("ROE") of at least 10.5% on a per books retail jurisdictional basis in any of those years, then APCo shall be entitled to defer an amount for T&D reliability expenditures sufficient to enable its ROE to equal 10.5%, up to a maximum annual deferral of $4.782 million.

Q. HOW MUCH DID THE COMPANIES EXPEND FOR RELIABILITY RELATED EXPENSES DURING 2007?

A. As shown on SHF Exhibit No. 14, the Companies reliability related expenditures for 2007 were $19,630,992.

Q. DID THE COMPANIES ACHIEVE AN ROE OF 10.5% DURING CALENDAR YEAR 2007?

A. No. SHF Exhibit No. 15 shows the Companies on a combined basis achieved an ROE of 8.705%.

~~Q. HAS APCO RECORDED A REGULATORY ASSET FOR THE $4.782~~ MILLION?

A. Yes. The APCo determined that it would not achieve an ROE of 10.5% and recorded a regulatory asset in December 2007 for the entire $4.782 million.

Q. IS APCO SEEKING RECOVERY OF THE $4.782 MILLION IN THIS ENEC PROCEEDING?

A. Yes. The Commission order provides for APCo, at its election, to obtain recovery of any such deferral in succeeding ENEC or base rate case(s) following such deferrals.

Q. HAVE YOU CALCULATED THE CHANGE IN THE COMPANIES ROE AFTER THE RECORDING OF THE $4.782 MILLION REGULATORY ASSET?

A. Yes. The recording of the regulatory asset increased the combined Companies per books ROE from 8.705% prior to the deferral to 9.010% after the deferral.

Q. PLEASE DESCRIBE SHF EXHIBIT NO.16.

A. SHF Exhibit No. 16, shows the right-of-way expenditures as filed in the 2005 Base Case and the Companies proposed method of assigning the $4.782 million recovery to the transmission and distribution services.

Q. HOW DO THE COMPANIES PROPOSE TO ASSIGN CLASS RESPONSIBILITY FOR THE RECOVERY OF THE $4.782 MILLION DEFERRAL?

A. The Companies propose to collect the transmission portion of the deferral from all customers. The Companies also propose to recover the distribution portion from all customer classes that are served at primary distribution or lower. This assigns the recovery responsibility to those classes that benefit most from the dollars spent in clearing right-of way.

Q. HAVE YOU INCLUDED THE RECOVERY OF THE $4.782 MILLION DEFERRAL IN THE PROPOSED ENEC RATES YOU ARE SUPPORTING AS SHOWN IN SHF EXHIBIT NO. 7?

A. Yes.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Appalachian Power Company
Monthly Internal Load Forecast

Total Company	July	August	September	October	November	December	January	February	March	April	May	June	12 Months June 2009
Internal Energy (GWH)													
Residential	1,087.4	1,041.2	837.9	720.5	1,027.7	1,474.5	1,598.6	1,349.2	1,180.0	855.8	747.8	895.7	12,798.3
Commercial	664.1	631.9	594.7	553.8	556.8	619.1	625.2	594.0	574.6	546.9	579.0	654.4	7,194.3
Total Industrial	1,164.5	1,166.9	1,160.9	1,209.9	1,197.5	1,102.0	1,144.6	1,162.3	1,199.5	1,204.2	1,227.8	1,213.5	14,249.4
Total Other Ultimate	66.7	65.4	70.0	68.7	70.9	75.6	71.8	72.3	71.5	64.7	66.3	70.8	834.7
Total Ultimate Sales	2,982.7	2,905.4	2,663.5	2,552.9	2,852.7	3,381.2	3,440.2	3,177.8	3,028.6	2,671.6	2,620.7	2,834.4	35,088.7
APCo State Peaks	203.7	245.1	228.4	219.1	234.4	257.3	276.6	258.4	237.7	221.2	221.6	234.8	2,850.7
Kingsport Power Company	5.8	5.5	4.0	5.1	5.0	8.7	7.6	6.8	5.6	5.2	4.6	4.6	88.3
Cooperatives	66.1	66.9	58.9	55.0	55.0	60.3	62.9	59.2	56.1	53.2	55.0	59.8	710.4
Municipals	28.1	28.9	27.8	25.8	25.2	25.6	26.1	26.2	25.9	25.9	26.2	27.3	319.0
State Agencies	5.1	5.0	4.3	5.1	6.5	7.9	7.8	6.0	5.2	4.8	4.0	4.4	85.9
Private Systems													
Total Sales-for-Resale	308.8	351.4	323.4	311.1	326.1	387.8	383.2	356.6	332.5	310.1	311.6	330.9	4,013.3
Total Internal Sales	3,271.2	3,256.9	2,987.0	2,864.1	3,178.7	3,729.1	3,823.4	3,534.3	3,358.1	2,981.8	2,932.4	3,165.5	39,082.0
Total Losses	193.5	191.3	175.5	168.3	187.0	219.6	224.9	186.4	105.6	147.5	172.2	186.1	2,158.0
Total Internal Energy	3,464.7	3,448.2	3,162.5	3,032.4	3,365.7	3,948.7	4,048.3	3,720.7	3,463.7	3,129.1	3,104.6	3,351.6	41,240.0
Internal Peak Demand (MW)	6717	6810	6191	5409	6559	7074	7911	7362	6774	5521	5891	6702	6,578.4
Kingsport Demand (MW)	371	428	407	401	439	482	520	505	470	410	397	432	438.3

West Virginia Monthly Internal Load	July	August	September	October	November	December	January	February	March	April	May	June	12 Months June 2009
Residential	486.2	496.6	393.2	322.5	470.7	687.7	751.3	636.6	555.1	387.3	347.6	420.4	5,955.2
Commercial	343.2	332.8	314.4	294.9	293.2	319.6	326.5	307.7	304.5	287.2	307.7	347.8	3,779.5
Total Industrial	668.2	678.1	683.3	715.9	700.3	720.2	711.3	706.2	730.2	715.6	728.2	719.8	8,475.3
Total Other Ultimate	2.1	2.8	2.9	3.3	3.9	3.5	3.4	2.6	3.7	2.4	2.4	2.0	34.8
Total Ultimate Sales	1,499.7	1,510.1	1,393.8	1,336.6	1,468.1	1,731.0	1,792.5	1,653.1	1,593.5	1,392.7	1,383.9	1,489.8	18,244.8
Sales-for-Resale	5.1	6.0	4.3	6.1	6.5	7.9	7.8	6.0	5.2	4.6	4.0	4.4	66.9
Total Internal Sales	1,504.8	1,516.1	1,398.1	1,342.7	1,474.6	1,738.9	1,800.3	1,659.1	1,598.7	1,397.3	1,387.9	1,494.2	18,311.7
Total Losses	93.1	94.1	86.9	83.5	91.6	107.9	111.7	92.1	62.0	72.7	86.2	92.8	1,064.5
Total Internal Energy	1,597.9	1,609.2	1,485.0	1,426.2	1,566.2	1,846.8	1,912.0	1,751.2	1,660.7	1,470.0	1,474.1	1,587.0	19,376.2

Virginia Monthly Internal Load	July	August	September	October	November	December	January	February	March	April	May	June	12 Months June 2009
Residential	581.2	544.6	444.7	398.0	557.0	786.8	847.3	712.8	624.9	468.5	400.2	475.3	6,841.1
Commercial	320.9	289.1	260.3	258.9	263.4	289.5	298.7	286.3	270.1	259.7	271.3	308.6	3,414.8
Total Industrial	496.3	488.8	477.6	494.0	497.2	471.8	433.3	456.1	469.3	488.4	501.4	493.9	5,768.1
Total Other Ultimate	64.6	62.8	67.1	65.4	67.0	72.1	68.4	69.7	67.8	62.3	63.9	66.8	799.9
Total Ultimate Sales	1,463.0	1,395.3	1,269.7	1,216.3	1,384.6	1,630.2	1,647.7	1,524.7	1,432.1	1,278.9	1,236.8	1,344.6	16,823.9
Cooperatives	5.6	5.5	4.0	5.1	5.0	8.7	7.6	6.8	5.6	5.2	4.6	4.6	66.3
Municipals	66.1	66.9	58.9	55.0	55.0	60.3	62.9	59.2	58.1	53.2	55.0	59.8	710.4
State Agencies	28.1	28.9	27.8	25.8	25.2	25.6	26.1	26.2	25.9	25.9	26.2	27.3	319.0
Total Sales-for-Resale	99.8	101.3	90.7	85.9	85.2	92.6	96.6	92.2	89.6	84.3	85.8	91.7	1,095.7
Total Internal Sales	1,562.8	1,496.6	1,360.4	1,302.2	1,469.8	1,722.8	1,744.3	1,616.9	1,621.7	1,363.2	1,322.6	1,436.3	17,919.6
Total Losses	96.8	93.0	84.6	81.0	91.3	107.0	108.3	89.8	49.5	70.9	82.1	89.2	1,043.4
Total Internal Energy	1,659.6	1,589.6	1,445.0	1,303.2	1,561.1	1,829.8	1,852.6	1,706.7	1,571.2	1,434.1	1,404.7	1,525.5	18,963.0

Wheeling Monthly Internal Load	July	August	September	October	November	December	January	February	March	April	May	June	12 Months June 2009
Wheeling Residential	42.9	43.8	33.7	24.8	33.4	45.4	49.6	41.6	36.9	30.1	27.4	33.9	443.5
Wheeling Commercial	42.0	40.5	37.3	34.4	33.1	35.7	35.1	34.5	33.8	32.6	34.9	38.9	432.8
Wheeling Industrial	107.2	107.9	116.7	120.4	114.0	108.8	111.7	111.6	111.0	125.9	131.5	104.4	1,373.3
Wheeling Other Ultimates	0.4	0.4	0.5	0.6	0.6	0.6	0.7	0.5	0.4	0.6	0.4	0.4	6.0
Total Ultimate Sales	192.5	192.6	190.2	180.2	181.1	190.5	197.1	188.4	182.1	189.1	194.2	177.6	2,255.6
Total Losses	3.0	3.0	2.9	2.8	2.8	2.9	3.0	2.9	2.8	2.9	3.0	2.7	35.0
Total Wheeling Ultimate Sales	195	195.56	193.10	182.97	183.67	193.40	200.13	191.30	184.87	192.00	197.16	180.31	2,290.6

APCo State Peaks
Load Forecast

	Forecast MW Peaks			
	WV	VA	KNG	Total
Jul-08	2,999.5	3,363.4	354.1	6,717.0
Aug-08	3,012.7	3,379.6	417.6	6,810.0
Sep-08	2,793.8	3,001.2	396.0	6,191.0
Oct-08	2,414.3	2,606.0	388.7	5,409.0
Nov-08	2,950.4	3,184.7	423.9	6,559.0
Dec-08	3,137.7	3,456.9	479.4	7,074.0
Jan-09	3,607.9	3,802.0	501.1	7,911.0
Feb-09	3,301.9	3,578.5	501.5	7,382.0
Mar-09	3,007.7	3,307.1	459.2	6,774.0
Apr-09	2,404.9	2,723.9	392.2	5,521.0
May-09	2,562.2	2,936.1	392.6	5,891.0
Jun-09	2,911.0	3,358.6	432.4	6,702.0
Total	35,104.0	38,698.3	5,138.7	78,941.0
Average	2,925.34	3,224.86	428.22	6,578.42

Appalachian Power
Forecast Jurisdictional Energy Allocation Factors
For the Twelve Months Ending 6/30/2009

Jurisdiction	MWH Sales	Loss Factor	MWH Load	Energy Allocation Factor
State of West Virginia				
WV Retail	18,244,800	1.058106	19,304,931	0.468112
Total Retail	18,244,800		19,304,931	0.468112
WV Sales for Resale Distribution	66,900	1.065300	71,269	0.001728
Total West Virginia	18,311,700		19,376,200	0.469840
State of Virginia				
Virginia Retail / Locals	17,919,600	1.058227	18,963,000	0.459821
Total Virginia	17,919,600		18,963,000	0.459821
State of Tennessee				
Kingsport Power	2,850,700	1.017575	2,900,800	0.070339
Total Company	39,082,000		41,240,000	1.000000

Appalachian Power
Forecast Jurisdictional Demand Allocation Factors
For the Twelve Months Ending 6/30/2009

Jurisdiction	MW Load	Loss Factor [1]	MW Load	Demand Allocation Factor
State of West Virginia				
WV Retail	2,662	1.0946	2,914.0	0.442967
Total Retail	2,662		2,914.0	0.442967
WV Sales for Resale Distribution	10	1.0956	11.3	0.001721
Total West Virginia	2,673		2,925.3	0.444687
State of Virginia				
Virginia Retail / Locals	2,750	1.1005	3,026.4	0.460056
Virginia Sales for Resale	190	1.0456	198.4	0.030162
Total Virginia	2,940		3,224.9	0.490218
State of Tennessee				
Kingsport Power	413	1.0370	428.2	0.065095
Total Company	6,025		6,578.4 6,578.4	1.000000

[1] Loss Factors calculated based on December, 2006 Jurisdictional Losses.

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC ENERGY
12 MONTHS ENDING JUNE 30, 2009

(1) TARIFF SCH.		(2) 2007 ACTUAL ENERGY SALES DIRECTLY ASSIGNABLE (KWH)	(3) 2007 ACTUAL ENERGY SALES TO BE ALLOCATED (KWH)	(4) DIRECT ASSIGNMENT FORECAST (KWH)	(5) ALLOCATED FORECAST (KWH)	(6) LOSS FACTORS	(7) MWH AT GENERATION CALCULATED (Col 4 or Col 5 X Col 6) (KWH)	(8) RATIO	(9) FORECASED YEAR 2009 ENERGY REQUIREMENT (Col 7 X Col 8) (KWH)	(10) CLASS ENERGY ALLOCATION FACTORS
RS		6,244,888,685		6,397,935,610		1.088900	6,966,712,086		6,918,424,019	0.321048
- On-Peak			219,700		227,115	1.091260	247,839		246,121	0.000011
- Off-Peak			517,061		534,040	1.087160	580,581		576,557	0.000027
SWS			94,512,401		97,887,973	1.088530	106,532,225		105,793,823	0.004909
SGS			239,256,664		248,163,664	1.087427	269,859,868		267,989,400	0.012436
SS	-SEC		333,932,826		343,965,598	1.087530	374,072,907		371,480,112	0.017238
	-PRI		40,045,221		41,248,351	1.057930	43,637,868		43,335,403	0.002011
	-AF		4,502,054		4,637,315	1.057930	4,905,955		4,871,850	0.000226
MGS	-SEC		1,394,029,189		1,451,098,507	1.087800	1,578,504,955		1,567,563,933	0.072742
	-PRI		131,496,076		136,492,055	1.058260	144,444,082		143,442,903	0.006656
	-SUBTRAN		9,916,600		10,214,537	1.038730	10,610,146		10,536,606	0.000489
	-TRANS		0		0		0		0	0.000000
	-AF		2,469,179		2,590,914	1.058260	2,741,861		2,722,856	0.000126
GS:TOD										
ON-PEAK	-SEC		9,043,689		9,335,547	1.089830	10,174,160		10,103,640	0.000469
OFF-PEAK	-SEC		11,736,184		12,096,082	1.086090	13,137,433		13,046,375	0.000605
ON-PEAK	- PRI		3,118,586		3,516,202	1.059860	3,726,682		3,700,851	0.000172
OFF-PEAK	-PRI		4,946,400		5,577,060	1.055660	5,887,479		5,846,672	0.000271
LGS	-SEC		1,303,187,951		1,360,203,092	1.087000	1,478,540,761		1,468,292,616	0.068136
	-PRI		142,576,168		149,396,129	1.057580	157,998,359		156,903,231	0.007281
	-SUBT		37,122,048		38,237,363	1.038750	39,719,051		39,443,748	0.001830
	-TRANS		0		0	0.000000	0		0	0.000000
LCP	-SEC		115,485,477		120,255,596	1.086650	130,699,795		129,793,881	0.006023
	- PRI		685,029,083		710,070,988	1.057640	750,999,479		745,794,110	0.034608
	- SUBT		1,048,740,910		1,093,771,155	1.038690	1,136,089,161		1,128,214,636	0.052354
	- TRANS		423,681,395		436,410,598	1.022360	446,168,739		443,076,229	0.020561
IP	-SEC		90,520,471		95,023,519	1.086400	103,233,551		102,518,013	0.004757
	- PRI		1,079,051,679		1,120,204,499	1.056880	1,183,899,326		1,175,693,417	0.054558
	- SUBT		914,335,815		976,632,399	1.038590	1,014,320,643		1,007,290,127	0.046743
	- TRANS		572,922,817		590,135,872	1.022320	603,307,704		599,126,024	0.027802
OL			77,840,628		80,566,469	1.085870	87,484,712		86,878,333	0.004032
SL			29,663,562		30,904,747	1.086140	33,566,882		33,334,221	0.001547

Case No. 2007-00522
March 18, 2008 Hearing
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Item No. 3

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC ENERGY
12 MONTHS ENDING JUNE 30, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TARIFF SCH.	2007 ACTUAL ENERGY SALES DIRECTLY ASSIGNABLE (KWH)	2007 ACTUAL ENERGY SALES TO BE ALLOCATED (KWH)	DIRECT ASSIGNMENT FORECAST (KWH)	ALLOCATED FORECAST (KWH)	LOSS FACTORS	MWH AT GENERATION CALCULATED (Col 4 or Col 5 X Col 6) (KWH)	RATIO	FORECASED YEAR 2009 ENERGY REQUIREMENT (Col 7 X Col 8) (KWH)	CLASS ENERGY ALLOCATION FACTORS
SPECIAL CONTRACT A									
FIRM	26,159,534		26,280,000		1.022560	26,872,877		26,686,814	
P1	213,155,720		473,358,288		1.022560	484,037,251		480,682,265	
P2	13,469,474		52,361,712		1.022560	53,542,992		53,171,872	
P2.5	123,097		284,264		1.022560	290,677		288,663	
P3	907,876		2,096,533		1.022560	2,143,830		2,128,971	
P4	0		0		1.022560	0		0	
	253,815,701		554,380,797		1.022560	566,887,628		562,958,384	0.026124
SPECIAL CONTRACT B									
138 Kv									
P1	472,460,424		472,460,424		1.022260	482,977,393		479,629,753	
P2	34,881,132		34,881,132		1.022260	35,657,586		35,410,434	
P2.5	1,096,224		1,096,224		1.022260	1,120,626		1,112,859	
P3	963,480		963,480		1.022260	984,927		978,100	
P4	612		612		1.022260	626		621	
	509,401,872		509,401,872		1.022260	520,741,158		517,131,767	0.023997
46 Kv									
P1	534,636		534,636		1.038529	555,235		551,387	
P2	61,488		61,488		1.038529	63,857		63,414	
P2.5	444		444		1.038529	461		458	
P3	1,548		1,548		1.038529	1,608		1,596	
P4	0		0		1.038529	0		0	
	598,116		598,116		1.038529	621,161		616,855	0.000029
SPECIAL CONTRACT C									
P1	2,546,575		2,546,575		1.098310	2,796,929		2,777,543	
P2	566,669		566,669		1.098310	622,378		618,064	
P3	2,354		2,354		1.098310	2,585		2,568	
P4	0		0		1.098310	0		0	
	3,115,598		3,115,598		1.098310	3,421,892		3,398,174	0.000158

ENEC Factors for 2008 Filing.xls

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC ENERGY
12 MONTHS ENDING JUNE 30, 2009

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TARIFF SCH.		2007 ACTUAL ENERGY SALES DIRECTLY ASSIGNABLE (KWH)	TO BE ALLOCATED (KWH)	DIRECT ASSIGNMENT FORECAST (KWH)	ALLOCATED FORECAST (KWH)	LOSS FACTORS	MWH AT GENERATION CALCULATED (Col 4 or Col 5 X Col 6) (KWH)	RATIO	FORECASED YEAR 2009 ENERGY REQUIREMENT (Col 7 X Col 8) (KWH)	CLASS ENERGY ALLOCATION FACTORS
SPECIAL CONTRACT D		198,796,528		198,796,528		1.022310	203,231,679		201,823,028	0.009366
SPECIAL CONTRACT E										
SEC	ON -PEAK	704,212		704,212						
	OFF-PEAK	2,107,291		2,107,291						
	SHOLD. PEAK	691,893		691,893						
		3,503,396		3,503,396		1.086460	3,806,300		3,779,917	0.000175
PRI	ON -PEAK	148,953		148,953						
	OFF-PEAK	433,677		433,677						
	SHOLD. PEAK	144,954		144,954						
		727,584		727,584		1.057410	769,355		764,022	0.000035
SPECIAL CONTRACT F		42,903,470		42,903,470		1.038500	44,555,254		44,246,430	0.002053
SPECIAL CONTRACT G	FIRM	550,279,261		550,279,261		1.022340	562,572,500		558,673,166	0.025925
SPECIAL CONTRACT H		2,777,631,848		2,774,216,392		1.022560	2,836,802,713		2,817,140,107	0.130729
SPECIAL CONTRACT I		249,164,000		249,164,000		1.022320	254,725,340		252,959,774	0.011739
TOTALS		10,834,826,059	8,799,898,864	11,285,022,624	9,169,377,376		21,699,939,270	0.993069	21,549,531,430	1.000000
					20,454,400,000				20,454,400,000	

Case No. 2007-00522
March 18, 2008 Hearing
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APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST COINCIDENT PEAK AND BILLING DEMANDS
JULY 2008 - JUNE 2009

(1) TARIFF SCH.		(2) COINCIDENT PEAK DATA AVERAGE CP DEMAND (KW) 2007 Actual Direct Assigned	(3) 2007 Data Allocable	(3) ALLOCATION Ratios	(4) Allocable KW	(5) 2008 FORECASTED CP DEMAND Forecasted (kW)	(6) Alloc. Ratios	(7) BILLING DEMAND DATA 2007 MO. AVG. BILLING DEMAND (kW)	(8) RATIO OF 2007 BILLING DEMAND TO COINCIDENT DEMAND (Col. 7 / Col.2)	(9) FORECASED YEAR JUNE 2009 BILLING DEMANDS (Col. 8 * Col.4) (kW)
RS			1,347,331	0.507501	1,361,216	1,361,216	0.4222520			
			48	0.000018	49	49	0.0000150			
- On-Peak										
- Off-Peak										
SWS			20,990	0.007906	21,206	21,206	0.0065780			
SGS			35,809	0.013488	36,178	36,178	0.0112220			
SS	-SEC		59,000	0.022224	59,608	59,608	0.0184900	99,381	1.684415	100,405
	-PRI		6,928	0.002610	6,999	6,999	0.0021710	8,811	1.271832	8,902
	-AF		787	0.000296	795	795	0.0002470			
MGS	-SEC		251,104	0.094584	253,692	253,692	0.0786950	476,297	1.896812	481,206
	-PRI		22,954	0.008646	23,191	23,191	0.0071940	46,068	2.006985	46,543
	-SUBTRAN		1,711	0.000644	1,729	1,729	0.0005360	2,796	1.633937	2,824
	-TRANS		0	0.000000	0	0	0.0000000			
	-AF		441	0.000166	446	446	0.0001380			
GS-TOD										
ON-PEAK	-SEC		3,735	0.001407	3,773	3,773	0.0011710			
OFF-PEAK	-SEC		0	0.000000	0	0	0.0000000			
ON-PEAK	- PRI		1,482	0.000558	1,497	1,497	0.0004640			
OFF-PEAK	-PRI		0	0.000000	0	0	0.0000000			
LGS	-SEC		196,745	0.074108	198,773	198,773	0.0616690	247,502	1.257983	250,053
	-PRI		20,979	0.007902	21,195	21,195	0.0065750	28,644	1.365373	28,939
	-SUBT		5,513	0.002077	5,570	5,570	0.0017280	9,365	1.698637	9,461
	-TRANS		0	0.000000	0	0	0.0000000			
LCP	-SEC		19,766	0.007445	19,970	19,970	0.0061950	22,821	1.154541	23,056
	- PRI		100,768	0.037956	101,808	101,808	0.0315800	157,906	1.567022	159,533
	- SUBT		150,033	0.056513	151,579	151,579	0.0470200	223,572	1.490150	225,876
	- TRANS		57,103	0.021509	57,691	57,691	0.0178960	95,093	1.665283	96,073
IP	-SEC		12,765	0.004808	12,897	12,897	0.0040010	13,930	1.091233	14,073
	- PRI		140,716	0.053004	142,166	142,166	0.0441000	165,170	1.173784	166,872
	- SUBT		125,650	0.047329	126,945	126,945	0.0393780	140,280	1.116511	141,735
	- TRANS									
	All Other		72,478	0.027300	73,225	73,225	0.0227140	87,689	1.209865	88,592
OL			0	0.000000	0	0	0.0000000			
SL			0	0.000000	0	0	0.0000000			

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST COINCIDENT PEAK AND BILLING DEMANDS
JULY 2008 - JUNE 2009

(1)	(2)	(3)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	COINCIDENT PEAK DATA						BILLING DEMAND DATA		
TARIFF SCH.	AVERAGE CP DEMAND (KW) 2007 Actual Direct Assigned	2007 Data Allocable	ALLOCATION Ratios	2008 FORECASTED CP DEMAND Allocable KW	Forecasted (kW)	Alloc. Ratios	2007 MO. AVG. BILLING DEMAND (kW)	RATIO OF 2007 BILLING DEMAND TO COINCIDENT DEMAND (Col. 7 / Col.2)	FORECASED YEAR JUNE 2009 BILLING DEMANDS (Col. 8 * Col.4) (kW)
SPECIAL CONTRACT A	56000				56,000	0.0173710	80,000	1.428571	80,000
SPECIAL CONTRACT B	43211				43,211	0.0134040	110,000	2.545652	110,000
SPECIAL CONTRACT C	1,052				1,052	0.0003260			
SPECIAL CONTRACT D	25,974				25,974	0.0080570	40,883 _1/	n/a	40,883 _2/
SPECIAL CONTRACT E									
SEC	379				379	0.0001180			
PRI	96				96	0.0000300			
SPECIAL CONTRACT F	5186				5,186	0.0016090	5,328	1.027397	5,328
SPECIAL CONTRACT G	51,307				51,307	0.0159150	56,930	1.109600	56,930
SPECIAL CONTRACT H	331,617				331,617	0.1028680	325,234	0.980752	325,234
SPECIAL CONTRACT I	26,702				26,702	0.0082830	41,152	1.541174	41,152
SUB-TOTAL	541,524	2,654,836	1.000000	2,682,196	3,223,720	1.000000	2,484,860		2,503,672

Total Coincident Peak Demand Forecast June 2008	
Total APCo	2,914,020
Total WPCo	309,700
Total	3,223,720

_1/ Sum of the firm billing demand and On-peak billing demand
_2/ Forecasted billing demand equal to 2006 billing demand

Appalachian Power Company
Wheeling Power Company
Summary of ENEC Over/Under Recovery for 2007

		Total Demand Related Cost	Total Energy Cost	ENEC Demand Revenues	ENEC Energy Revenues	ENEC Over/Under Recovery	Demand Over/Under Revenues	Energy Over/Under Revenues
RS	APCo	$43,479,178	$83,475,157		$121,522,265	($2,417,725)		($2,417,725)
	WPCo		$6,432,343		$9,445,092			
RS-TOD ONPEAK	APCo		$3,091		$4,571			
RS-TOD OFFPEAK	APCo		$7,287		$7,365			
RS-TOD ONPEAK	WPCo		$131		$174			
RS-TOD OFFPEAK	WPCo		$216		$211			
SWS	APCo	$682,837	$1,358,769		$1,891,587	[illegible]		($37,148)
SWS	WPCo				$112,871			
SGS - SEC	APCo	$1,178,346	$3,421,875		$4,332,649	[illegible]		$75,932
	WPCo	$1,877			$345,380			
SGS - TOD ONPEAK					$0			
SGS- TOD OFFPEAK					$0			
SS - SEC	APCo	$1,963,458	$4,789,336	$1,823,071	$4,965,992	[illegible]	($140,386)	$176,656
SS - PRI	APCo	$236,555	$561,085	$159,418	$586,611	[illegible]	($77,137)	$25,525
SS - AF	APCo	$25,827	$63,431	$0	$89,786	[illegible]		$528
MGS - SEC	APCo	$8,420,366	$19,914,668	$6,520,773	$18,392,641	[illegible]	($1,112,152)	$797,549
	WPCo			$787,441	$2,319,575			
MGS - PRI	APCo	$771,610	$1,828,245	$617,862	$1,746,398	[illegible]	($86,168)	$74,848
	WPCo			$67,580	$155,694			
MGS - SUBTRAN	APCo	$57,591	$135,169	$39,389	$136,259	[illegible]	($18,202)	$1,089
	WPCo			$0	$0			
MGS - TRANS		$0		$0	$0		$0	$0
MGS - AF	APCo	$15,195	$34,044		$39,145	[illegible]		($320)
	WPCo				$9,774			
GS - TOD - SEC						[illegible]		($12,529)
ON - PEAK	APCo	$125,181	$129,203	$0	$235,339			
OFF- PEAK	APCo		$168,102	$0	$174,620			
ON - PEAK	WPCo			$0	$5,455	[illegible]		$6,574
OFF- PEAK	WPCo			$0	$1,119			
GS - TOD - PRI						[illegible]		($10,556)
ON - PEAK	WPCo	$46,419	$43,738	$0	$78,289			
OFF- PEAK	WPCo		$66,764	$0	$68,075			
LGS - SEC	APCo	$6,617,828	$18,528,844	$4,934,985	$16,650,700	[illegible]	($805,068)	$850,068
	WPCo			$877,775	$2,728,212			
LGS - PRI	APCo	$696,581	$1,984,403	$537,703	$1,677,153	[illegible]	($46,611)	$65,935
	WPCo			$112,268	$373,186			
LGS - SUBTRAN	APCo	$183,166	$506,191	$208,027	$528,302	[illegible]	$24,861	$22,111
	WPCo							
LGS - TRANS		$0	$0				$0	$0
LCP - SEC	APCo	$671,527	$1,653,216	$450,029	$1,530,376	[illegible]	($162,751)	$78,935
	WPCo			$58,747	$201,776			
LCP - PRI	APCo	$3,455,015	$9,544,296	$3,223,791	$9,280,297	[illegible]	($67,570)	$407,790
	WPCo			$163,654	$671,789			
LCP - SUBTRAN	APCo	$5,010,648	$14,282,327	$4,141,206	$12,919,129	[illegible]	($402,884)	$505,096
	WPCo			$466,557	$1,868,294			
LCP - TRAN	APCo	$1,925,622	$5,697,132	$1,945,370	$5,913,968	[illegible]	$19,748	$216,837
IP - SEC	APCo	$436,996	$1,282,278	$300,151	$1,073,060	[illegible]	($58,850)	$64,812
	WPCo			$77,995	$274,030			
IP - PRI	APCo	$4,725,002	$14,879,274	$3,984,889	$14,264,957	[illegible]	($401,023)	$687,315
	WPCo			$339,089	$1,301,631			
IP - SUBTRAN	APCo	$3,976,669	$12,425,183	$2,213,145	$7,903,699	[illegible]	($637,849)	$607,580
	WPCo			$1,435,280	$5,129,064			
Air Products		$309,605						
IP - TRAN	APCo	$2,427,435	$7,695,712	$2,220,466	$8,015,416	[illegible]	($206,968)	$319,704
OL	APCo	$0	$1,113,992		$1,104,247	[illegible]		$49,730
	WPCo				$59,474			
SL	APCo	$0	$425,271		$388,643	[illegible]	$0	$16,885
	WPCo				$53,513			

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Appalachian Power Company
Wheeling Power Company
Summary of ENEC Over/Under Recovery for 2007

		Total Demand Related Cost	Total Energy Cost	ENEC Demand Revenues	ENEC Energy Revenues	ENEC Over/Under Recovery	Demend Over/Under Revenues	Energy Over/Under Revenues
SPECIAL CONTRACT A	APCo	$796,023	$3,382,362			$853,975	$629,039	$224,935
FIRM DEMAND				$75,474	$370,351			
INTERRUPTIBLE DEMAND				$1,349,588	$0			
	P1			$0	$3,030,073			
	P2			$0	$191,340			
	P2.5			$0	$1,855			
	P3				$13,678			
	P4							
SPECIAL CONTRACT B	APCo	$1,360,447	$6,017,925	$935,370	$0	($100,119)	($425,077)	$324,958
CAPACITY CHARGE					$5,891,431			
	138 Kv P1				$405,660			
	P2				$4,390			
	P2.5				$37,592			
	P3				$0			
	P4				$0			
	46 Kv P1				$3,579			
	P2				$227			
	P2.5				$3			
	P3				$0			
	P4				$0			
SPECIAL CONTRACT C	APCo	$29,851	$54,048		$51,766	[illegible]		($20,422)
	P1				$11,352			
	P2				$360			
	P3				$0			
	P4				$0			
SPECIAL CONTRACT D	APCo	$840,802	$2,666,416	$255,180	$67,260	[illegible]	($239,292)	$99,910
FIRM LOAD				$344,242	$0			
ON-PEAK				$847	$0			
SHOULDER -PEAK				$1,241	$0			
OFF - PEAK					$2,699,065			
INTERRUPT. ENERGY								
SPECIAL CONTRACT E	APCo	$11,839	$49,623		$14,736	[illegible]		$2,890
SECONDARY					$36,940			
ON-PEAK					$12,677			
OFF - PEAK								
SHOULDER -PEAK								
PRIMARY		$3,073	$10,108		$3,261	[illegible]		$324
ON-PEAK					$7,561			
OFF - PEAK					$2,683			
SHOULDER -PEAK								
SPECIAL CONTRACT F	APCo	$170,183	$584,539	$153,119	$610,403	[illegible]	($17,064)	$25,864
FIRM POWER								
BACK-UP POWER								
MAINTENANCE								
SPECIAL CONTRACT G	WPCo	$1,746,941 $398,497	$7,404,320	$1,431,726	$7,743,776	[illegible]	($713,712)	$339,456
SPECIAL CONTRACT H	APCo	$11,050,696	$37,221,315	$10,108,179	$38,950,035	[illegible]	($952,517)	$1,728,720
SPECIAL CONTRACT I	APCo	$893,385	$3,340,810	$890,360	$3,487,406	[illegible]	($3,025)	$146,597
TOTAL		$104,752,269	$273,180,237	$53,251,989	$324,226,313	($454,205)	($5,900,657)	$5,446,452

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APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC - ENERGY RELATED
ALLOCATED TO CUSTOMER CLASSES
JULY 2008 - JUNE 2009

(1) TARIFF SCH.			(2) ENERGY ALLOCATION FACTOR	(3) ENEC - ENERGY RELATED (ENERGY ENEC X Col.2) ($)	(4) Reliability Expenditures Distribution Tariffs	(4) Reliability Expenditures Allocated Share
RS			0.321048	131,978,350	130,180,338	1,735,552
- On-Peak			0.000011	4,608	4,578	61
- Off-Peak			0.000027	10,795	10,725	143
SWS			0.004909	2,018,525	2,004,650	26,726
SGS			0.012436	4,940,875	4,907,311	65,424
SS	-SEC		0.017238	6,776,616	6,735,020	89,791
	-PRI		0.002011	785,550	780,763	10,409
	-AF		0.000226	90,688	90,119	1,201
MGS	-SEC		0.072742	28,542,683	28,342,488	377,859
	-PRI		0.006656	2,609,989	2,592,298	34,560
	-SUBTRAN		0.000489	193,585		
	-TRANS		0.000000	0		
	-AF		0.000126	51,306	50,902	679
GS:TOD						
ON-PEAK	-SEC		0.000469	195,215	193,907	2,585
OFF-PEAK	-SEC		0.000605	244,281	242,726	3,236
ON-PEAK	- PRI		0.000172	79,985	78,912	1,052
OFF-PEAK	-PRI		0.000271	109,463	107,990	1,440
LGS	-SEC		0.068136	26,630,639	26,438,445	352,475
	-PRI		0.007281	2,871,000	2,849,197	37,985
	-SUBT		0.001830	706,653		
	-TRANS		0.000000	0		
LCP	-SEC		0.006023	2,350,255	2,333,781	31,114
	- PRI		0.034608	13,550,991	13,460,946	179,460
	- SUBT		0.052354	20,339,842		
	- TRANS		0.020561	7,969,457		
IP	-SEC		0.004757	1,853,840	1,839,600	24,525
	- PRI		0.054558	21,317,119	21,173,011	282,277
	- SUBT		0.046743	18,003,151		
	- TRANS		0.027802	10,749,772		
OL			0.004032	1,576,316	1,566,055	20,878
SL			0.001547	607,035	602,733	8,036
SPECIAL CONTRACT A			0.026124	10,176,306		
SPECIAL CONTRACT B			0.024026	9,240,986		
SPECIAL CONTRACT C			0.000158	84,315	83,176	1,109
SPECIAL CONTRACT D			0.009366	3,628,981		
SPECIAL CONTRACT E		-SEC	0.000175	67,840	66,914	892
		-PRI	0.000035	13,976	13,785	184
SPECIAL CONTRACT F			0.002053	791,635		
SPECIAL CONTRACT G			0.025925	9,982,612		
SPECIAL CONTRACT H			0.130729	50,320,870		

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC - ENERGY RELATED
ALLOCATED TO CUSTOMER CLASSES
JULY 2008 - JUNE 2009

(1) TARIFF SCH.	(2) ENERGY ALLOCATION FACTOR	(3) ENEC - ENERGY RELATED (ENERGY ENEC X Col.2)	(4) Reliability Expenditures Distribution Tariffs	Allocated Share
SPECIAL CONTRACT I	0.011739	4,527,098		
TOTALS	1.000000	$398,149,984 395,993,185	$246,750,368	$3,289,653

ENERGY-RELATED ENEC 12 MONTHS ENDING JUNE 30, 2008	
Fossil Generation	$662,495,000
Purchased Power Cost - Affiliated	$468,230,000
Purchased Power Cost - Non Affiliated	$266,390,000
Consumables / Other Costs	$40,276,000
Transmission Losses	$90,567,000
Loss (Gain) on Sale of Allowances	($26,161,000)
Sales to Affiliates	($238,038,000)
Sales to Non Affiliates	($540,510,000)
FORECAST APCo ENEC -ENERGY	$723,249,000
Less:	
Surplus Power _1/	$0
Buy-Through Power _2/	$2,311
FORECAST APCo ENEC -ENERGY - Adjusted	$723,246,689
WV ENERGY ALLOCATION FACTOR	0.468112
WV RETAIL ENEC -ENERGY RELATED	$338,560,323
Reliability Expenditures	$1,492,347
Wheeling Purchases from OPCO	$59,795,000
Less:	
Surplus Power _3/	$98,062
Backup Power _4/	$256,597
Maintenance Power _5/	$1,343,028
Total Wheeling Power ENEC - ENERGY RELATED	$58,097,313

Estimated Credits based on 2006 actuals

_1/ Special Contract B Surplus Power	$0
_2/ Special Contract B Buy Through Power	$0
Special Contract D Buy Through Power	$2,311
_3/ Special Contract G Surplus Power	$98,062
_4/ Special Contract G Backup Power	$256,597
_5/ Special Contract G Maintenance Power	$1,343,028

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC - DEMAND RELATED
ALLOCATION TO CUSTOMER CLASSES
JULY 2008 - JUNE 2009

(1) TARIFF SCH.		(2) DEMAND ALLOCATION FACTOR	(3) ENEC - DEMAND RELATED (DEMAND ENEC X COL.2) ($)
RS			
- On-Peak		0.422252	66,998,965
- Off-Peak		0.000015	2,380
SWS		0.006578	1,043,735
SGS		0.011222	1,780,601
SS	**-SEC**	0.018490	3,074,205
	-PRI	0.002171	421,610
	-AF	0.000247	39,192
MGS	**-SEC**	0.078695	13,598,732
	-PRI	0.007194	1,227,644
	-SUBTRAN	0.000536	103,249
	-TRANS	0.000000	0
	-AF	0.000138	21,897
GS:TOD			
ON-PEAK	**-SEC**	0.001171	185,803
OFF-PEAK	**-SEC**	0.000000	0
ON-PEAK	**- PRI**	0.000464	73,623
OFF-PEAK	**-PRI**	0.000000	0
LGS	**-SEC**	0.061659	10,588,537
	-PRI	0.006575	1,089,870
	-SUBT	0.001728	249,322
	-TRANS	0.000000	0
LCP	**-SEC**	0.006195	1,145,715
	- PRI	0.031580	5,078,386
	- SUBT	0.047020	7,863,574
	- TRANS	0.017896	2,819,820
IP	**-SEC**	0.004001	693,690
	- PRI	0.044100	7,398,395
	- SUBT	0.039378	6,885,979
	- TRANS	0.022714	3,811,012
OL		0.000000	0
SL		0.000000	0
SPECIAL CONTRACT A		0.017371	2,127,227
SPECIAL CONTRACT B		0.013404	2,551,897
SPECIAL CONTRACT C		0.000326	51,727

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC - DEMAND RELATED
ALLOCATION TO CUSTOMER CLASSES
JULY 2008 - JUNE 2009

(1) TARIFF SCH.		(2) DEMAND ALLOCATION FACTOR	(3) ENEC - DEMAND RELATED (DEMAND ENEC X COL.2)
SPECIAL CONTRACT D		0.008057	1,517,701
SPECIAL CONTRACT E	**-SEC**	0.000118	18,723
	-PRI	0.000030	4,760
SPECIAL CONTRACT F		0.001609	272,365
SPECIAL CONTRACT G		0.015915	3,238,954
SPECIAL CONTRACT H		0.102868	17,274,641
SPECIAL CONTRACT I		0.008283	1,317,293
TOTAL		1.000000	$158,670,569 $164,571,225

DEMAND-RELATED ENEC **12 MONTHS ENDING JUNE 30, 2008**	
Purchased Power Cost - Affiliated	**$290,379,000**
Purchased Power Cost - Non Affiliated	**$37,986,000**
Transmission Settlement	**-$29,348,000**
FTR Revenue	**$1,282,000**
3rd Party Transmission Revenue	**($27,818,000)**
FORECAST TOTAL COMPANY ENEC -DEMAND	**$272,481,000**
WV DEMAND ALLOCATION FACTOR	**0.442967**
WV RETAIL ENEC -DEMAND RELATED	**$120,699,969**
Wheeling Purchases from OPCO	**$38,228,000**
Less:	
Backup power	**$257,400**
Total Wheeling Power Company ENEC	**$37,970,600**

_1/ Special Contract G Backup Power $257,400

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
EXPANDED NET ENERGY COST (ENEC) RATES
CASE NO. 08-____-E-GI
EFFECTIVE DATE JULY 1, 2008

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
RS		3.110	
RS -TOD / RS-LM-TOD	ON-PEAK	3.077	
	OFF-PEAK	2.021	
SWS		3.129	
SGS		2.708	
SGS - LM-TOD	ON-PEAK	2.708	
	OFF-PEAK	2.099	
SS	-SEC	1.970	2.670
	-PRI	1.904	2.609
	-AF	2.801	
MGS	-SEC	1.967	2.350
	-PRI	1.912	2.296
	-SUBTRAN	1.895	2.287
	-TRANS	1.867	2.234
	-AF	2.825	
GS:TOD			
ON-PEAK	-SEC	4.081	
OFF-PEAK	-SEC	2.020	
ON-PEAK	- PRI	4.369	
OFF-PEAK	-PRI	1.963	
LGS	-SEC	1.958	3.456
	-PRI	1.922	3.377
	-SUBT	1.848	3.363
	-TRANS	1.821	3.286
LCP	-SEC	1.954	2.875
	- PRI	1.908	2.809
	- SUBT	1.860	2.797
	- TRANS	1.826	2.733
IP	-SEC	1.951	3.922
	- PRI	1.903	3.832
	- SUBT	1.843	3.816
	- TRANS	1.822	3.729
OL		1.957	
SL		1.964	

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
EXPANDED NET ENERGY COST (ENEC) RATES
CASE NO. 08-____-E-GI
EFFECTIVE DATE JULY 1, 2008

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
SPECIAL CONTRACT A			
	FIRM POWER	1.836	3.728
	INTERRUPTIBLE DEMAND		2.157
	P1	1.836	
	P2	1.836	
	P2.5	1.836	
	P3	1.836	
	P4	1.836	
SPECIAL CONTRACT B			
	138 KV SERVICE		
	CAPACITY CHARGE		1.933
	P1	1.812	
	P2	1.812	
	P2.5	1.812	
	P3	1.812	
	P4	1.812	
	46 KV SERVICE		
	P1	1.839	
	P2	1.839	
	P2.5	1.839	
	P3	1.839	
	P4	1.839	
SPECIAL CONTRACT C			
	P1	4.201	
	P2	4.923	
	P3	49.228	
	P4	35.584	
SPECIAL CONTRACT D			
	FIRM POWER	1.8390	3.801
	ON-PEAK DEMAND		2.837
	SHOULD. PEAK DEM.		1.732
	OFF-PEAK DEMAND		0.626
	INTERR. ENERGY	1.8200	
SPECIAL CONTRACT E			
	-SEC		
	ON-PEAK	2.814	
	OFF-PEAK	2.358	
	SHOULDER PEAK	2.465	
	-PRI		
	ON-PEAK	3.037	
	OFF-PEAK	2.418	
	SHOULDER PEAK	2.572	
SPECIAL CONTRACT F			
	FIRM POWER	1.845	4.261
	BACK-UP POWER	1.845	0.426
	MAINTENANCE	1.933	
SPECIAL CONTRACT G		1.814	4.759
SPECIAL CONTRACT H		1.814	4.426
SPECIAL CONTRACT I		1.817	2.664

FLOODWALL ENEC Factor for floodwall accounts is the energy component of the appropriate general service tariff for which the customer would qualify.

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
BILLING ANALYSIS INCLUDING BOTH "IN PERIOD" AND "PRIOR PERIOD"
12 MONTHS ENDED JUNE 30, 2009

Tariff	BILLING UNITS Demand (KW)	BILLING UNITS Energy (KWH)	CURRENT ENEC RATES ENEC Demand $/KW	CURRENT ENEC RATES ENEC Energy $/KWH	CURRENT ENEC RATES Revenue ($)	TARGET REVENUE Energy ENEC ($)	TARGET REVENUE Demand ENEC ($)	TARGET REVENUE Total ($)	PROPOSED ENEC RECOVERY ENEC Demand $/KW	PROPOSED ENEC RECOVERY ENEC Energy $/KWH	PROPOSED ENEC RECOVERY Revenue ($)	Revenue Difference (Target-Current) ($)	Revenue Difference (Proposed - Target) ($)	FINAL ENEC RATES Adjustment Factor	FINAL ENEC RATES ENEC Demand $/KW	FINAL ENEC RATES ENEC Energy $/KWH
RS	0	6,397,935,610		0.02277	145,880,994	129,763,683	66,998,965	196,762,648		0.03076	196,736,520	51,081,654	26,128	1.000133		0.030760
RS-TOD ONPEAK	0	227,115		0.02351	5,339	4,530	2,380	6,910		0.03043	6,911	1,571	-1	0.999892		0.03043
RS-TOD OFFPEAK	0	534,040		0.01688	8,481	10,613	0	10,613		0.01987	10,611	2,132	1	1.000113		0.01987
SWS	0	97,667,973		0.02298	2,249,006	1,984,473	1,043,735	3,028,208		0.03094	3,028,035	779,202	173	1.000057		0.03094
SGS - SEC	0	248,163,664		0.02071	5,139,469	4,856,892	1,780,601	6,637,493		0.02676	6,636,378	1,498,024	-885	0.999867		0.02676
SGS - TOD ONPEAK	0	0		0.02071	0	0	0	0			0	0	0			
SGS - TOD OFFPEAK	0	0		0.01599	0	0	0	0			0	0	0			
SS - SEC	1,204,856	343,965,598	1.679	0.01570	7,423,214	6,661,100	3,074,205	9,735,305	2.670	0.01937	9,679,746	2,312,091	-144,441	1.000000	2.670	0.01937
SS - PRI	106,625	41,248,351	1.830	0.01534	806,874	772,140	421,610	1,193,750	2.609	0.01872	1,050,852	386,877	142,898	1.000000	2.609	0.01872
					8,230,088	7,433,240	3,495,816	10,929,056			10,930,598	2,698,968	-1,543			
SS - AF	0	4,837,315		0.02113	97,966	89,149	39,192	128,341		0.02766	128,361	30,364	-20	0.999844		0.02766
MGS - SEC	5,774,468	1,451,066,607	1.360	0.01562	30,519,435	28,056,267	13,598,732	41,654,999	2.350	0.01933	41,619,497	11,135,564	35,502	1.000399	2.351	0.01933
MGS - PRI	558,517	136,492,055	1.320	0.01528	2,822,841	2,565,476	1,227,644	3,793,120	2.296	0.01880	3,848,392	970,278	-55,272	1.000398	2.297	0.01880
MGS - SUBTRAN	33,894	10,214,537	1.285	0.01479	194,626	192,856	103,249	296,105	2.287	0.01868	270,372	101,478	26,733	1.000399	2.288	0.01868
MGS - TRANS	0	0	1.284	0.01457	0	0			2.234	0.01860	0	0	0	1.000399	2.235	0.01860
					33,536,903	30,814,598	14,929,626	45,744,223			45,738,281	12,207,320	5,962			
MGS - AF	0	2,590,914		0.02100	54,409	50,439	21,897	72,335		0.02782	72,338	17,926	-3	0.999957		0.02782
GS - TOD - SEC																
ON - PEAK	0	9,335,547		0.02903	276,612	191,931	185,803	377,734		0.04046	377,716	101,121	18	1.000084		0.04046
OFF- PEAK	0	12,096,082		0.01587	191,965	240,142	0	240,142		0.01985	240,107	48,177	35	1.000084		0.01985
					468,577	432,072	185,803	617,876			617,823	149,299	52			
GS - TOD - PRI																
ON - PEAK	0	3,516,202		0.02663	94,340	76,677	73,623	152,300		0.04331	152,267	57,960	13	0.999979		0.04331
OFF- PEAK	0	5,577,060		0.01542	85,998	107,616	0	107,616		0.01930	107,637	21,620	-19	0.999979		0.01930
					180,338	186,295	73,623	259,916			259,924	79,580	-6			
LGS - SEC	3,000,631	1,360,203,092	2.196	0.01586	27,890,166	26,176,482	10,588,537	36,765,019	3.457	0.01924	36,543,260	8,874,853	221,759	1.000520	3.459	0.01924
LGS - PRI	347,272	149,396,129	2.131	0.01614	3,001,895	2,822,149	1,089,870	3,912,019	3.377	0.01869	3,994,999	910,124	-82,980	1.000520	3.379	0.01869
LGS - SUBTRAN	113,533	36,237,353	2.077	0.01509	812,810	703,922	249,322	953,243	3.364	0.01841	1,085,819	140,433	-132,576	1.000520	3.366	0.01841
LGS - TRANS	0	0	2.041	0.01487	0	0	0		3.288	0.01814	0	0	0	1.000520	3.288	0.01814
					31,704,871	29,702,553	11,927,729	41,630,281			41,624,079	9,925,410	6,203			
LCP - SEC	276,670	120,255,596	2.013	0.01567	2,441,342	2,310,153	1,145,715	3,455,868	2.875	0.01921	3,105,622	1,014,526	350,246	1.000268	2.876	0.01921
LCP - PRI	1,914,396	710,070,986	1.954	0.01529	14,597,715	13,319,883	5,078,386	18,398,269	2.809	0.01876	18,698,917	3,800,554	-300,648	1.000268	2.810	0.01876
LCP - SUBTRAN	2,710,509	1,093,771,155	1.904	0.01500	21,567,376	20,261,711	7,863,574	28,125,285	2.798	0.01852	27,839,358	6,557,909	285,927	1.000268	2.798	0.01852
LCP - TRAN	1,152,672	436,410,596	1.872	0.01474	8,590,869	7,938,773	2,819,820	10,758,593	2.733	0.01819	11,089,591	2,167,725	-330,997	1.000268	2.734	0.01819
					47,197,302	43,830,520	16,907,496	60,738,016			60,733,489	13,540,713	4,527			
IP - SEC	168,878	95,023,519	2.562	0.01588	1,922,633	1,822,216	693,690	2,515,906	3.922	0.01918	2,484,889	593,272	31,016	1.000249	3.923	0.01918
IP - PRI	2,002,469	1,120,204,499	2.487	0.01524	22,052,056	20,953,424	7,398,395	28,351,819	3.832	0.01870	28,620,841	6,299,761	-269,022	1.000249	3.833	0.01870
IP - SUBTRAN	1,700,624	976,632,398	2.423	0.01499	16,760,617	17,933,394	6,885,979	24,819,373	3.816	0.01838	24,421,002	6,058,556	398,372	1.000249	3.817	0.01836
IP - TRAN	1,063,107	590,135,872	2.382	0.01472	11,219,122	10,708,261	3,811,012	14,519,293	3.728	0.01815	14,674,657	3,300,171	-155,364	1.000249	3.729	0.01815
					53,954,630	51,417,316	18,789,076	70,206,391			70,201,388	16,251,760	5,002			
OL	0	80,568,469		0.01569	1,264,088	1,549,421	0	1,549,421		0.01923	1,549,293	285,333	128	1.000083		0.01923
SL	0	30,904,747		0.01569	464,895	598,691	0	598,691		0.01931	598,771	111,795	-80	0.999866		0.01931

SHF Exhibit No. 1
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APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
BILLING ANALYSIS INCLUDING BOTH "IN PERIOD" AND "PRIOR PERIOD"
12 MONTHS ENDED JUNE 30, 2009

Tariff		BILLING UNITS Demand (KW)	BILLING UNITS Energy (KWH)	CURRENT ENEC RATES ENEC Demand $/KW	CURRENT ENEC RATES ENEC Energy $/KWH	CURRENT ENEC RATES Revenue ($)	TARGET REVENUE Energy ENEC ($)	TARGET REVENUE Demand ENEC ($)	TARGET REVENUE Total ($)	PROPOSED ENEC RECOVERY ENEC Demand $/KW	PROPOSED ENEC RECOVERY ENEC Energy $/KWH	PROPOSED ENEC RECOVERY Revenue ($)	Revenue Difference (Target-Current) ($)	Revenue Difference (Proposed - Target) ($)	FINAL ENEC RATES Adjustment Factor	FINAL ENEC RATES ENEC Demand $/KW	FINAL ENEC RATES ENEC Energy $/KWH
SPECIAL CONTRACT A																	
FIRM DEMAND		36,000	28,280,000	2.382	0.01607	481,792				3.728	0.01829	614,884			0.999812	3.728	0.01829
INTERRUPTIBLE DEMAND		924,000		1.973		1,823,052				2.157		1,993,005				2.157	
	P1		473,358,288		0.01507	7,133,509					0.01829	8,657,723					0.01829
	P2		52,361,712		0.01507	769,091					0.01829	957,698					0.01829
	P2.5		284,284		0.01507	4,284					0.01829	5,199					0.01829
	P3		2,096,533		0.01507	31,595					0.01829	38,346					0.01829
	P4		0		0.01507	0					0.01829	0					0.01829
			554,380,797			10,263,323	10,137,320	2,127,227	12,264,547			12,268,852	2,001,224	-2,305			
SPECIAL CONTRACT B																	
CAPACITY CHARGE		1,320,000		0.981		1,294,920				1.9333		2,651,897			0.999792	1.933	
138 Kv	P1		472,460,424		0.01465	6,921,545					0.01805	8,527,911					0.01805
	P2		34,881,132		0.01465	511,009					0.01805	629,604					0.01805
	P2.5		1,096,224		0.01465	16,060					0.01805	19,787					0.01805
	P3		963,480		0.01465	14,115					0.01805	17,391					0.01805
	P4		612		0.01465	9					0.01805	11					0.01805
			509,401,872			8,757,657	9,194,335	2,551,897	11,746,232			11,746,601	2,988,575	-368			
46 Kv	P1		534,636		0.01487	7,950					0.01832	9,796					0.01832
	P2		61,468		0.01487	914					0.01832	1,126					0.01832
	P2.5		444		0.01487	7					0.01832	8					0.01832
	P3		1,548		0.01487	23					0.01832	28					0.01832
	P4		0		0.01487	0					0.01832	0					0.01832
			598,116			8,894	10,796	0	10,788			10,957	1,902	-162			
			509,999,988			8,766,551	9,205,131	2,551,897	11,757,028			11,757,558	2,990,477	-530			
SPECIAL CONTRACT C																	
	P1	0	2,546,575		0.02246	57,198					0.04160	105,928			1.000000		0.04160
	P2		566,669		0.02632	14,916					0.04875	27,822			1.000000		0.04875
	P3		2,354		0.26318	620					0.48741	1,147			1.000000		0.48741
	P4		0		0.18024	0					0.35233	0			1.000000		0.35233
			3,115,598			72,730	82,971	51,727	134,698			134,698	61,967	0			
SPECIAL CONTRACT D																	
FIRM LOAD		120,000	58,800,000	2.416	0.01494	1,168,392				3.801	0.01832	1,533,583				3.801	0.01832
ON-PEAK		370,601		1.199		444,351				2.988		1,100,043			0.955820	2.837	
SHOULDER -PEAK		4,012		0.732		2,937				1.812		7,288			0.955820	1.732	
OFF - PEAK		5,106		0.265		1,353				0.655		3,344			0.955820	0.626	
INTERRUPT. ENERGY			139,998,528		0.01465	2,050,849					0.01813	2,537,535					0.01813
			198,798,528			3,667,982	3,615,004	1,517,701	5,132,704			5,161,774	1,464,723	-49,069			
SPECIAL CONTRACT E																	
SECONDARY																	
ON-PEAK			704,212		0.02224	15,662					0.02666	18,777			1.041200		0.02776
OFF - PEAK			2,107,291		0.01864	39,280					0.02235	47,094			1.041200		0.02327
SHOULDER -PEAK			691,893		0.01948	13,478					0.02335	16,159			1.041200		0.02432
			3,503,396			68,420	66,686	18,723	85,409			82,030	16,990	3,380			
PRIMARY																	
ON-PEAK			148,953		0.02399	3,573					0.02878	4,286			1.041600		0.02998
OFF - PEAK			433,677		0.01910	8,283					0.02292	9,939			1.041600		0.02387
SHOULDER -PEAK			144,954		0.02032	2,945					0.02438	3,534			1.041600		0.02540
			727,584			14,802	13,739	4,760	18,499			17,760	3,697	739			
SPECIAL CONTRACT F																	
FIRM POWER		63,937	42,903,470	2.667	0.01498	812,356				4.260	0.01838	1,060,930			1.000019	4.260	0.01838
BACK-UP POWER		0	0	0.267	0.01498	0				0.426	0.01838	0			1.000019	0.426	0.01838
MAINTENANCE			0		0.01551	0					0.01926	0					0.01926
			42,903,470			812,356	788,571	272,365	1,060,936			1,060,930	248,580	5			
SPECIAL CONTRACT G		683,163	550,279,261	2.325	0.01474	9,699,470	9,943,922	3,238,954	13,182,877	4.741	0.01807	13,182,501	3,483,408	376	1.002611	4.753	0.01807
SPECIAL CONTRACT H		3,902,808	2,774,216,392	2.911	0.01478	52,363,992	50,125,778	17,274,641	67,400,419	4.426	0.01807	67,400,292	15,036,426	128	1.000143	4.427	0.01807
SPECIAL CONTRACT I		493,829	249,164,000	1.795	0.01474	4,559,100	4,509,580	1,317,293	5,826,873	2.868	0.01810	5,827,162	1,267,773	-288	0.998442	2.663	0.01810
TOTAL			20,454,400,000			420,546,105	391,211,185	164,571,226	555,782,410			555,784,337	135,236,305	-1,927			

Case No. 2007-00522
March 18, 2008 Hearing
Supplemental Data Request
Item No. 3
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SHF Exhibit No. 9
Consisting of 21 pages
Proposed Tariff Schedules

SCHEDULE R.S.
(Residential Service)

AVAILABILITY OF SERVICE

Available for electric service through one meter to individual residential customers, including rural residential customers engaged principally in agricultural pursuits.

MONTHLY RATE (Schedule Codes 011, 015, 018, 038, 039, 051)

Customer Charge .... $ 4.00/month

Energy Charge:
(I) First 500 KWH .... 7.288¢/KWH
(I) All Over 500 KWH .... 6.070¢/KWH

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the Customer Charge.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt and payable by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company within twenty (20) days of the mailing date. Effective October 1, 2006, any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company by the next scheduled read date shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

TERM

Contracts may be required pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

SPECIAL TERMS AND CONDITIONS

This Schedule is subject to the Company's Terms and Conditions of Service.

This Schedule is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes, as well as for the usual farm uses outside the home, but service under this Schedule shall not be extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

(C) Indicates Change, (D) Indicates Decrease, (I) Indicates Increase, (N) Indicates New, (O) Indicates Omission, (T) Indicates Temporary

Issued Pursuant to
P.S.C. West Virginia
Case No. 08-____-E-GI

Issued By
D. E. Waldo, President & COO
Charleston, West Virginia

Effective: Service rendered on or after
July 1, 2008

SCHEDULE R.S.
(Residential Service)
(continued)

SPECIAL TERMS AND CONDITIONS (Cont'd)

This Schedule is intended for single-phase service. Where the residential customer requests three-phase service, this Schedule will apply if the customer pays to the Company the difference between constructing single-phase and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service schedule will apply to such service.

The Company shall have the option of reading meters monthly or bi-monthly.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

S.R.R.-R.S. AMENDMENT

This SRR-RS Amendment shall be applicable to electric service for the billing months of December, January, February, March, and April to residential customers who qualify for special reduced rates under the provision of West Virginia Code §24-2A. The rates and charges for service under this amendment shall be twenty percent (20%) less than the rates and charges for service rendered under this Schedule. The Company shall apply all relevant and applicable requirements and conditions of West Virginia Code §24-2A, and all other requirements of Terms and Conditions of Service of the Company's West Virginia P.S.C. Tariff and this Schedule.

LOAD MANAGEMENT WATER HEATING PROVISION (Schedule Codes 011, 051)

(I) For residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at 3.519¢/KWH.

This provision, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "MONTHLY RATE", as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 9 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the load management water heating system(s) and devices which qualify the residence for service under the Load Management Water Heating Provision. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated, it may discontinue billing the customer under this provision and commence billing under the standard monthly rate.

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE R.S.-T.O.D.
(Residential Service Time-of-Day)

AVAILABILITY OF SERVICE

Available for electric service to individual residential customers, including rural residential customers engaged principally in agricultural pursuits who wish to be metered through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

MONTHLY RATE (Schedule Codes 030, 032)

Customer Charge $12.60/month

Energy Charge:

(I) All KWH during the on-peak billing period . . . . 10.321¢/KWH

(I) All KWH during the off-peak billing period . . . . 2.955¢/KWH

For the purpose of this Schedule, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 9 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the Customer Charge.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt and payable by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company within twenty (20) days of the mailing date. Effective October 1, 2006, any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company by the next scheduled read date shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

SEPARATE METERING PROVISION

Customers shall have the option of receiving service under this schedule for load associated with energy storage devices with time-differentiated load characteristics and service under Schedule R.S. for general use load. Such general use load shall be separately wired to a standard residential meter.

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE S.W.S.
(Sanctuary Worship Service)

AVAILABILITY OF SERVICE

Available for service only to the building in which the sanctuary or principal place of worship is located.

MONTHLY RATE (Schedule Code 222)

Customer Charge .... \$ 8.00/month

Energy Charge:
(I) First 7,000 KWH .... 6.925¢/KWH
(I) All over 7,000 KWH .... 5.856¢/KWH

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the Customer Charge.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt and payable by the "Last Pay Date" shown on the bill. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company by the next bill preparation date shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

TERM

Contracts may be required pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

SPECIAL TERMS AND CONDITIONS

This Schedule is subject to the Company's Terms and Conditions of Service.

Religious organizations which have auxiliary buildings, such as classrooms, day care centers, etc., that are separated from the church building containing the principal place of worship and served at one point of delivery through a single meter, shall separate the wiring in the sanctuary building from the wiring in the other buildings and the sanctuary building shall be individually metered in order to be served under this Schedule.

The Company shall have the option of reading meters monthly or bi-monthly.

(C) Indicates Change, (D) Indicates Decrease, (I) Indicates Increase, (N) Indicates New, (O) Indicates Omission, (T) Indicates Temporary

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE S.S.
(School Service)

AVAILABILITY OF SERVICE

Available for service to all primary and secondary school, college and university buildings and public libraries for which the entire electrical requirements are furnished by the Company.

MONTHLY RATE

Schedule Codes	Service Voltage	Demand Charge ($/KW)	Energy Charge ¢/KWH	Customer Charge $/Month
634, 636	Secondary	(I) 4.583	(I) 4.289	15.00
635	Primary	~~(I) 3.532~~	~~(I) 4.157~~	~~60.00~~

MINIMUM CHARGE

Customers with demands below 500 KW are subject to a minimum monthly charge equal to the Customer Charge. Customers with demands of 500 KW, or more are subject to a minimum monthly charge equal to the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand and all applicable adjustments.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt and payable by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company within twenty (20) days of the mailing date.

MEASUREMENT AND DETERMINATION OF DEMAND AND ENERGY

The billing demand in KW shall be taken monthly as the single highest 15-minute peak in KW as registered during the month by a demand meter or indicator. Where service is delivered through two meters to an existing customer, the monthly billing demand will be taken as the sum of the two demands separately determined and the billing KWH taken as the sum of the KWHs separately determined.

Monthly billing demands for customers with actual or contracted demands of 500 KW or more of capacity shall not be less than 60% of the greater of (a) the customer's contract capacity in excess of 100 KW, or (b) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

Billing demands will be rounded to the nearest whole KW.

(C) Indicates Change, (D) Indicates Decrease, (I) Indicates Increase, ~~(N) Indicates New, (O) Indicates Omission, (T) Indicates Temporary~~

SCHEDULE S.S.
(School Service)
(continued)

METERED VOLTAGE ADJUSTMENT

The rates set forth in this Schedule are based upon delivery and measurement of energy at the same voltage. When the measurement of energy occurs at a voltage different than the delivery voltage, the measurement of energy will be compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment or the application of multipliers to the metered quantities. In such cases, metered KWH and KW will be adjusted for billing purposes. In cases where multipliers are used to adjust metered usage, the adjustment shall be as follows:

(a) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(b) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

ATHLETIC FIELD LIGHTING

Available to separately metered athletic field lighting facilities. In order to be eligible for the Athletic Field Lighting charges in this provision, a new or existing customer requiring an increase in lighting load must furnish and maintain the required equipment in order to receive the entire service at the primary voltage of the distribution line from which service is to be supplied. Athletic fields receiving service at the effective date of this provision shall not be required to purchase and maintain the required equipment supplying the existing secondary voltage service that is serving the customer's present load requirement at their present location.

Monthly Rate

Schedule Code	Service Voltage	Energy Charge (¢/KWH)	Customer Charge ($/Month)
698	Primary	(I) 6.106	25.00

TERM

For customers with demands greater than 1,000 KW, contracts will be required for an initial period of not less than one (1) year and shall remain in effect thereafter until either party shall give to the other at least six month's written notice of the intention to discontinue service under the terms of this schedule. Such customers shall contract for a definite amount of electrical capacity sufficient to meet their normal maximum requirements. For customers with demands less than 1,000 KW, a written agreement may be required at the option of the customer or the Company, pursuant to the Extension of Service provisions of the Company's Terms and Conditions of Service.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required. The Company reserves the right to make initial contracts for periods of longer than one year pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

SCHEDULE S.G.S.
(Small General Service)

AVAILABILITY OF SERVICE

Available for general service to customers with maximum electrical capacity requirements of 10 KW or less. When a customer being served under this Schedule establishes or exceeds a maximum requirement of 10 KW, the customer will be placed on the appropriate general service Schedule.

MONTHLY RATE (Schedule Codes 231, 234, 281)

Customer Charge . . . . $ 8.00/month

(I) Energy Charge . . . . 5.972¢/KWH

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the Customer Charge.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company by the "Last Pay Date" shown on the bill, shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

TERM

For customers eligible for this Schedule, a written agreement may be required at the option of the customer or the Company, pursuant to the Company's Terms and Conditions of Service.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required. The Company reserves the right to make initial contracts for periods of longer than one year pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

SCHEDULE S.G.S.
(Small General Service)
(continued)

SPECIAL TERMS AND CONDITIONS

This Schedule is subject to the Company's Terms and Conditions of Service.

The Company shall have the option of reading meters monthly or bi-monthly.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

LOAD MANAGEMENT TIME-OF-DAY PROVISION

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company, such as electric thermal storage space heating and/or cooling systems and water heaters, which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours. A time-of-day meter is required to take service under this provision.

Customers who desire to separately wire their energy storage load to a time-of-day meter and their general-use load to a standard meter shall receive service under the appropriate provisions of this Schedule.

Monthly Rate (Schedule Code 225)

Customer Charge $12.60/month

Energy Charge:
(I) All KWH during the on-peak hours .... 9.434¢/KWH
(I) All KWH during the off-peak hours .... 2.879¢/KWH

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 9 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

The Company reserves the right to inspect at all reasonable times the customer's energy storage devices which qualify for service under this provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated, it may discontinue billing the customer under this provision and commence billing under the appropriate general service schedule.

OPTIONAL UNMETERED SERVICE PROVISION (Schedule Code 213)

Available to customers who qualify for Schedule S.G.S. and use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards which can be served by a standard service drop from the Company's existing secondary distribution system. This service will be furnished at the option of the Company.

SCHEDULE S.G.S.
(Small General Service)
(continued)

OPTIONAL UNMETERED SERVICE PROVISION (Cont'd)

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract. In the event one customer has several accounts for like service, the Company may meter one account to determine the appropriate kilowatt-hour usage applicable for each of the accounts.

The customer shall furnish switching equipment satisfactory to the Company. The customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the customer's equipment at any time to verify the actual load. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load for the full period such load was connected plus three months.

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at
(I) 5.972¢/KWH plus a monthly customer charge of $7.35.

This provision is subject to the Terms and Conditions of Schedule S.G.S.

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P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE M.G.S.
(Medium General Service)

AVAILABILITY OF SERVICE

Available for general service to customers with maximum demands exceeding 10 KW but less than 1,000 KW. When a customer being served under this Schedule establishes or exceeds a maximum requirement of 1,000 KW, the customer will be placed on the appropriate general service Schedule and required to contract for such capacity requirements. This Schedule is not available to customers being served under Schedule L.G.S. as of the effective date of this Schedule except in cases of material changes in load which result in a dramatic change in usage characteristics.

MONTHLY RATE

Schedule Codes	Service Voltage	Demand Charge ($/KW)	Off-Peak Excess Demand Charge ($/KW)	Energy Charge ¢/KWH	Customer Charge $/Month
215	Secondary	(I) 4.732	2.44	(I) 4.739	10.00
217	Primary	(I) 3.714	1.60	(I) 4.603	30.00
219	Subtransmission	(I) 2.075	0.63	(I) 4.486	70.00
239	Transmission	(I) 1.531	0.59	(I) 4.416	80.00

Reactive Demand Charge for each KVAR of leading or lagging
reactive demand in excess of 50% of the KW metered demand $0.62/KVAR
(Applicable to customers 300 KW or greater)

MINIMUM AND MAXIMUM CHARGES

Bills computed under the above rate are subject to the operation of Minimum and Maximum Charge provisions as follows:

(a) Minimum Charge - For demand accounts up to 100 KW - the Customer Charge.

For demand accounts over 100 KW - the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand, and all applicable adjustments.

(b) Maximum Charge - The sum of the Customer Charge, the product of 15¢/KWH and the metered energy, and all applicable adjustments. This provision shall not reduce the charge below the amount specified in the Minimum Charge provision above, (a).

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

SCHEDULE M.G.S.
(Medium General Service)
(continued)

METERED VOLTAGE ADJUSTMENT

The rates set forth in this Schedule are based upon delivery and measurement of energy at the same voltage. When the measurement of energy occurs at a voltage different than the delivery voltage, the measurement of energy will be compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment or the application of multipliers to the metered quantities. In such cases, metered KWH, KW and KVAR will be adjusted for billing purposes. In cases where multipliers are used to adjust metered usage, the adjustment shall be as follows:

(a) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(b) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

ATHLETIC FIELD LIGHTING

Available to separately metered athletic field lighting facilities. In order to be eligible for the Athletic Field Lighting charges in this provision, a new or existing customer requiring an increase in lighting load must furnish and maintain the required equipment in order to receive the entire service at the primary voltage of the distribution line from which service is to be supplied. Athletic fields receiving service at the effective date of this provision shall not be required to purchase and maintain the required equipment supplying the existing secondary voltage service that is serving the customer's present load requirement at their present location.

Monthly Rate

Schedule Code	Service Voltage	Energy Charge (¢/KWH)	Customer Charge ($/Month)
214	Primary	(I) 6.127	25.00

TERM

For customers eligible for service under this Schedule, a written agreement may be required at the option of the customer or the Company, pursuant to the Extension of Service provisions of the Company's Terms and Conditions of Service.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required. The Company reserves the right to make initial contracts for periods longer than one (1) year pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE G.S.-T.O.D.
(General Service Time-of-Day)

AVAILABILITY OF SERVICE

Available for general service to customers served at secondary or primary delivery voltage levels with maximum demands less than 500 KW. Availability of service under this Schedule is restricted to the first 500 customers applying for service.

MONTHLY RATE

Schedule Codes	Service Voltage	On-Peak Energy Charge (¢/KWH)	Off-Peak Energy Charge (¢/KWH)	Customer Charge ($/Month)
229	Secondary	(I) 10.107	(I) 2.867	12.80
227	Primary	(I) 9.609	(I) 2.749	45.60

For the purpose of this Schedule, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 9 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the Customer Charge.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company by the "Last Pay Date" shown on the bill shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

METERED VOLTAGE ADJUSTMENT

The rates set forth in this Schedule are based upon delivery and measurement of energy at the same voltage. When the measurement of energy occurs at a voltage different than the delivery voltage, the measurement of energy will be compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment or the application of multipliers to the metered quantities. In such cases, metered KWH will be adjusted for billing purposes. In cases where multipliers are used to adjust metered usage, the adjustment shall be as follows:

SCHEDULE L.G.S.
(Large General Service)

AVAILABILITY OF SERVICE

Available for general service to customers with maximum demands exceeding 10 KW but less than 1,000 KW. When a customer being served under this Schedule establishes or exceeds a maximum requirement of 1,000 KW, the customer will be placed on the appropriate general service Schedule and required to contract for such capacity requirements. This Schedule is not available to customers being served under Schedule M.G.S. as of the effective date of this Schedule except in cases of material changes in load which result in a dramatic change in usage characteristics.

MONTHLY RATE

Schedule Codes	Service Voltage	Demand Charge ($/KW)	Off-Peak Excess Demand Charge ($/KW)	Energy Charge (¢/KWH)	Customer Charge ($/Month)
380	Secondary	(I) 11.781	3.80	(I) 3.020	21.00
381	Primary	(I) 10.552	2.48	(I) 2.950	100.00
382	Subtransmission	(I) 8.761	0.98	(I) 2.806	125.00
390	Transmission	(I) 8.111	0.92	(I) 2.761	175.00

Reactive Demand Charge for each KVAR of leading or lagging reactive demand in excess of 50% of the KW metered demand $0.62/KVAR
(Applicable to customers 300 KW or greater)

MINIMUM AND MAXIMUM CHARGES

Bills computed under the above rate are subject to the operation of Minimum and Maximum Charge provisions as follows:

(a) Minimum Charge - For demand accounts up to 100 KW - the Customer Charge.

For demand accounts over 100 KW - the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand, and all applicable adjustments.

(b) Maximum Charge - The sum of the Customer Charge, the product of 15¢/KWH and the metered energy, and all applicable adjustments. This provision shall not reduce the charge below the amount specified in the Minimum Charge provision above, (a).

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

SCHEDULE L.C.P.
(Large Capacity Power Service)

AVAILABILITY OF SERVICE

Available for general service to customers. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet maximum requirements, but in no case shall the contract capacity be less than 1,000 kW.

MONTHLY RATE

Schedule Codes	Service Voltage	Demand Charge ($/KW)	Off-Peak Excess Demand Charge ($/KW)	Energy Charge (¢/KWH)	Customer Charge ($/Month)
386	Secondary	(I) 10.526	4.88	(I) 2.990	85.00
387	Primary	(I) 9.328	3.19	(I) 2.911	275.00
388	Subtransmission	(I) 7.557	1.27	(I) 2.792	375.00
389	Transmission	(I) 6.929	1.19	(I) 2.742	475.00

Reactive Demand Charge for each KVAR of leading or lagging reactive demand in excess of 50% of the KW metered demand $0.62/KVAR

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand, and all applicable adjustments.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents, of the Company by the "Last Pay Date" shown on the bill shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

MEASUREMENT AND DETERMINATION OF DEMAND AND ENERGY

The billing demand in KW shall be taken each month as the single highest 30-minute peak in KW as registered during the month in the on-peak period by a demand meter or indicator. The monthly billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

The off-peak excess demand shall be the amount by which the demand created during the off-peak period exceeds the monthly billing demand.

(C) Indicates Change, (D) Indicates Decrease, (I) Indicates Increase, (N) Indicates New, (O) Indicates Omission, (T) Indicates Temporary

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE I.P.
(Industrial Power Service)

AVAILABILITY OF SERVICE

Available for general service to customers. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet maximum requirements, but in no case shall the contract capacity be less than 1,000 KW.

MONTHLY RATE

Schedule Codes	Service Voltage	Demand Charge ($/KW)	Off-Peak Excess Demand Charge ($/KW)	Energy Charge (¢/KWH)	Customer Charge ($/Month)
327	Secondary	(I) 14.304	6.05	(I) 2.358	85.00
322	Primary	(I) 13.002	3.95	(I) 2.295	275.00
323	Subtransmission	(I) 11.154	1.56	(I) 2.172	375.00
324	Transmission	(I) 10.468	1.47	(I) 2.145	475.00

Reactive Demand Charge for each KVAR of leading or lagging reactive demand in excess of 50% of the KW metered demand $0.62/KVAR

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand, and all applicable adjustments.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company by the "Last Pay Date" shown on the bill shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

MEASUREMENT AND DETERMINATION OF DEMAND AND ENERGY

The billing demand in KW shall be taken each month as the single highest 30-minute peak in KW as registered during the month in the on-peak period by a demand meter or indicator. The monthly billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE O.L.
(Outdoor Lighting)

AVAILABILITY OF SERVICE

Available for outdoor lighting to individual customers located outside areas covered by municipal street lighting systems.

Customers requesting the installation of a new light shall have the obligation to insure that the requested location for the light will not be objectionable to other property owners in the immediate vicinity. In the event of a dispute that results in the removal or relocation of the installation, the customer will be responsible for the costs of removal or relocation.

Customers requesting a light that requires the installation of a new pole on their property may designate the location of the new pole, provided that the pole location is truck accessible to the Company.

MONTHLY RATE

A. Overhead Lighting Service

For each of the following, the Company will provide the lamp, photo-electric relay control equipment, luminaire and upsweep arm not over 6 feet in length, and shall mount same on an existing, truck accessible wood distribution pole carrying secondary circuits.

	Schedule Code	Wattage	Approx. Lumen	Type of Lamp	Rate per Lamp per Month
(I)	093	175 ③	7,000	Mercury Vapor	7.91
(I)	096	250 ①	11,000	Mercury Vapor	10.44
(I)	095	400 ②	21,000	Mercury Vapor	12.52
(I)	114	400	20,000	Mercury Vapor Floodlight	17.92
(I)	119	1,000	50,000	Mercury Vapor Floodlight	31.94
(I)	108	70	5,800	High Pressure Sodium	7.31
(I)	094	100	9,500	High Pressure Sodium	7.97
(I)	097	200	22,000	High Pressure Sodium	10.44
(I)	098	400	50,000	High Pressure Sodium	12.62
(I)	112	200	22,000	High Pressure Sodium Floodlight	9.68
(I)	107	250 ②	25,000	High Pressure Sodium Floodlight	11.82
(I)	109	400	50,000	High Pressure Sodium Floodlight	15.28
(I)	139	175 ②	10,800	Metal Halide Floodlight	11.49
(I)	110	250	17,000	Metal Halide Floodlight	13.78
(I)	116	400	28,800	Metal Halide Floodlight	15.22
(I)	131	1,000	88,000	Metal Halide Floodlight	33.49

SCHEDULE O.L.
(Outdoor Lighting)
(continued)

B. Post-Top Lighting Service

For each of the following, the Company will provide the lamp, photo-electric relay control, post-top luminaire, post and installation (the type and height of which will be consistent with the Company's construction standards), including underground wiring for a distance of 30 feet from the Company's existing secondary facilities.

MONTHLY RATE

	Schedule Code	Wattage	Approx. Lumen	Type of Lamp	Rate per Lamp per Month
~~(I)~~	~~099~~	~~175 **~~	~~7,000 **~~	Mercury Vapor	8.89
(I)	106	70 **	5,800 **	High Pressure Sodium	10.78
(I)	111	100	9,500	High Pressure Sodium	11.03
(I)	122	150 **	16,000 **	High Pressure Sodium	19.99
(I)	101	200	22,000	High Pressure Sodium	26.87
(I)	103	250 **	25,000 **	High Pressure Sodium	32.82
(I)	104	400	50,000	High Pressure Sodium	35.97
(I)	129	175 **	10,800 **	Metal Halide Floodlight	20.23
(I)	105	400	28,800	Metal Halide Floodlight	34.17
(I)	130	1,000	88,000	Metal Halide Floodlight	50.83

**Effective July 28, 2006, this lamp is no longer available for new installations or for repair or replacement of existing lights.

When the customer's service requires an underground circuit longer than 30 feet from the existing secondary facilities for post-top lighting service, the customer will pay to the Company, in advance, all costs for the length of underground circuit in excess of 30 feet.

The customer shall, where applicable, be subject to the following conditions in addition to paying the charges set forth in the above:

1. Customers requiring service where rock or other adverse soil conditions are encountered will be furnished service provided the excess cost of trenching and backfilling (cost in excess of $0.90 per foot of the total trench length) is paid to the Company by the customer.

2. In the event the customer requires that an underground circuit be located beneath a driveway or other pavement, the Company may require the customer to install protective conduit in the paved areas.

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE S.L.
(Street Lighting)

AVAILABILITY OF SERVICE

Available for lighting service to municipalities, counties and other governmental subdivisions for the lighting of public streets, public highways and other public outdoor areas where such service can be supplied from the existing general distribution system and where poles are truck accessible.

MONTHLY RATE

A. Overhead Service on Wood Distribution Poles

	Wattage	Approx. Lumen	Rate Per Lamp Per Month ($)	Cost of Facilities Included in Rates Per Lamp ($)
	Mercury Vapor:			
(I)	100	3,500 [1/]	4.33	---
(I)	175 **	7,000 **	5.52	207.00
(I)	250	11,000 [2/]	6.35	---
(I)	400 **	21,000 **	7.84	258.00
(I)	1,000	58,000 [3/]	13.80	---
	High Pressure Sodium:			
(I)	70 **	5,800 **	5.50	248.00
(I)	100	9,500	5.71	254.00
(I)	200	22,000	7.23	298.00
(I)	400	50,000	9.58	357.00

SCHEDULE S.L.
(Street Lighting)
(continued)

MONTHLY RATE (Cont.)

B. Service on Special Metal, Concrete, Ornamental Poles or
Wood Poles Served from Underground Distribution

	Wattage	Approx. Lumen	Rate Per Lamp Per Month ($)	Cost of Facilities Included in Rates Per Lamp ($)
	Mercury Vapor:			
(I)	175 **	7,000 **	10.75	547.00
(I)	400 **	21,000 **	13.65	639.00
	Mercury Vapor Post Top:			
(I)	175 **	7,000 **	6.15	243.00
	High Pressure Sodium:			
(I)	70 **	5,800 **	10.65	591.00
(I)	100	9,500	11.00	598.00
(I)	150 **	16,000 **	11.80	635.00
(I)	200	22,000	12.98	678.00
(I)	400	50,000	16.55	815.00
	High Pressure Sodium Post Top:			
(I)	100	9,500	5.05	204.00

The rates under Sections A&B above are based on the Company investing in new standard facilities in the amount as shown adjacent to the rate. When the investment in new facilities, including costs for service from underground, exceeds the stated amount, the difference will be paid to the Company by the customer as a Contribution in Aid-of-Construction to the Company.

SCHEDULE S.L.
(Street Lighting)
(continued)

C. Energy and Minor Maintenance

	Wattage		Approx. Lumen		Rate Per Lamp Per Month ($)
	Mercury Vapor:				
(I)	175	**	7,000	**	3.90
(I)	400	**	21,000	**	5.43
	High Pressure Sodium:				
(I)	100		9,500		2.80
(I)	150	**	16,000	**	3.00
(I)	200		22,000		3.55
(I)	250	**	27,000	**	4.39
(I)	400		50,000		4.85

MONTHLY RATE (Cont'd)

Applicable where the Customer installs and owns the street lighting system within a specified area as agreed to by the Customer and the Company.

1/Effective December 10, 1980, this lamp is no longer available for new installations or for repair or replacement of existing units.
2/Effective November 2, 1991, this lamp is no longer available for new installations or for repair or replacement of existing units.
3/Effective January 1, 2000, this lamp is no longer available for new installations or for repair or replacement of existing units.
**Effective July 28, 2006, this lamp is no longer available for new installations or for repair or replacement of existing lights.

HOURS OF LIGHTING

All lamps shall burn from one-half hour after sunset until one-half hour before sunrise, every night, burning approximately 4,000 hours per annum.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
(See Sheet Nos. 2-1 through 2-7 for Applicability)

First Revision of Original Sheet No. 29
Canceling Original Sheet No. 29

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE A.R.S.S
(Additional Retail Sales Surcharge)

(I)

Effective July 1, 2007, monthly bills of all residential and small commercial retail customers, shall be charged $0.000148/KWH, pursuant to P.S.C. West Virginia Case No. 06-0828-EW-SC order dated April 18, 2007. This surcharge shall apply to Schedules RS, MGS, SGS, SS, SWS, OL and SL.

(C) Indicates Change, (D) Indicates Decrease, ~~(I) Indicates Increase~~, (N) Indicates New, (O) Indicates Omission, (T) Indicates Temporary

Issued Pursuant to
P.S.C. West Virginia
Case No. 08- -E-GI

Issued By
D. E. Waldo, President & COO
Charleston, West Virginia

Effective: Service rendered on or after
July 1, 2008

Appalachian Power and Wheeling Power
Summary of Musser Over/Under Components
Expense, Depreciation and Return
Period Ended December 31, 2007

	May	June	July	August	September	October	November	December	Totals
					2007				
O&M Expense									
Incremental O&M		206,521.89	131,000.51	321,969.94	161,243.10	136,866.28	350,089.87	80,415.06	1,388,106.65
Depreciation Expense @ 3.37%	$ -	0.00	0.00	51.22	245.76	1,474.39	1,553.36	1,676.94	5,001.68
Total O&M	$ -	**206,521.89**	**131,000.51**	**322,021.16**	**161,488.86**	**138,340.67**	**351,643.23**	**82,092.00**	1,393,108.33
Capital Expenditures									
Amortization of Purchase Price	$ -	**0.00**	**0.00**	**16,666.67**	**16,666.67**	**16,666.67**	**16,666.67**	**16,666.67**	**83,333.33**
New Investments									655,544.02
General System Upgrades	$ -	0.00	18,240.16	69,271.77	437,494.22	28,119.54	44,005.45	58,412.88	
Total	$ -	0.00	18,240.16	69,271.77	437,494.22	28,119.54	44,005.45	58,412.88	
Cumulative additions per Dave Hummel			18,240.16	87,511.93	525,006.15	553,125.69	597,131.14	655,544.02	
Beginning Balance	$ -	0.00	0.00	18,240.16	87,511.93	525,006.15	553,125.69	597,131.14	
Ending Balance	$ -	0.00	18,240.16	87,511.93	525,006.15	553,125.69	597,131.14	655,544.02	
Average Balance - Investment	$ -	0.00	9,120.08	52,876.05	306,259.04	539,065.92	575,128.42	626,337.58	
Beginning Balance	$ -	0.00	0.00	0.00	51.22	296.99	1,771.38	3,324.74	
Ending Balance	$ -	0.00	0.00	51.22	296.99	1,771.38	3,324.74	5,001.68	
Average Accumulated Depreciation @ 3.37%	$ -	0.00	0.00	25.61	174.11	1,034.18	2,548.06	4,163.21	
Average Net Plant	$ -	0.00	9,120.08	52,850.43	306,084.93	538,031.74	572,580.35	622,174.37	
Return and Taxes @ 11.577%	$ -	**0.00**	**87.99**	**509.87**	**2,952.95**	**5,190.66**	**5,523.97**	**6,002.43**	20,267.87
Total Expenditures									$ 1,496,709.54
Revenues									
Total Recovered	$ -	$ -	$ 184,749	$ 170,876	$ 218,629	$ 157,257	$ 142,375	$ 164,066	$ 1,037,950.95

Case No. 2007-0052
March 18, 2008 Hearing
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SHF Exhibit No 10.xls

Appalachian Power Company and
Wheeling Power Company
PSC Case No. 08-_____-E-GI
Estimated Expenditures

Projected July 2007 – June 2008 Expenses

O&M Expenses – Year 1

• Right-of-Way Maintenance:	$ 900,000
• Property Owner Notification:	$ 104,000
• Service Entrance Upgrades/Inspections	$ 121,500
• System Improvement-related O&M	$ 480,000
• Mapping – Facility Inspections	$ 207,550
• Easements	$ 100,000
• Customer Service	$ 30,000
Total O&M	$1,943,050

Capital Expenditures – Year 1 Improvements

• Single Phase RF Metering Installation	$ 265,000
• Three Phase Transformer-rated Metering	$ 35,000
• System Improvements, Reliability, Sectionalizing, Pole replacements, etc	$ 720,000
Total Capital Improvements	$1,020,000

Acquisition Cost	$ 200,000

Projected July 2008 – June 2009 Expenses

O&M Expenses – Year 2

• System Improvement-related O&M	$ 1,006,500
Total O&M	$ 1,006,500

Capital Expenditures – Year 2 Improvements

• System Improvements, Reliability, Pole replacements, etc	$ 2,080,000
	$ 2,080,000

McDowell County Utilities
Estimated Acquisition / Improvement Cost
Cost Recovery

Year 2 Beginning July 2008

	July	August	September	October	November	December	January	February	March	April	May	June	Year 2 Totals
O&M Expense													
System Improvement O&M @ 60% Capital/ 40% of O&M	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 83,863	$ 1,006,350
Depreciation Expense @ 3.37%	$ 3,351	$ 3,838	$ 4,325	$ 4,812	$ 5,298	$ 5,785	$ 6,272	$ 6,759	$ 7,246	$ 7,732	$ 8,219	$ 8,706	$ 72,343
													$ 1,078,693
Capital Expenditures													
General System Upgrades	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 173,333	$ 2,080,000
Beginning Balance	$ 1,020,000	$ 1,193,333	$ 1,366,667	$ 1,540,000	$ 1,713,333	$ 1,886,667	$ 2,060,000	$ 2,233,333	$ 2,406,667	$ 2,580,000	$ 2,753,333	$ 2,926,667	
Ending Balance	$ 1,193,333	$ 1,366,667	$ 1,540,000	$ 1,713,333	$ 1,886,667	$ 2,060,000	$ 2,233,333	$ 2,406,667	$ 2,580,000	$ 2,753,333	$ 2,926,667	$ 3,100,000	
Average Balance - Investment	$ 1,106,667	$ 1,280,000	$ 1,453,333	$ 1,626,667	$ 1,800,000	$ 1,973,333	$ 2,146,667	$ 2,320,000	$ 2,493,333	$ 2,666,667	$ 2,840,000	$ 3,013,333	
Beginning Balance	$ 22,411	$ 25,762	$ 29,600	$ 33,925	$ 38,736	$ 44,035	$ 49,820	$ 56,092	$ 62,851	$ 70,096	$ 77,828	$ 86,047	
Ending Balance	$ 25,762	$ 29,600	$ 33,925	$ 38,736	$ 44,035	$ 49,820	$ 56,092	$ 62,851	$ 70,096	$ 77,828	$ 86,047	$ 94,753	
Average Accumulated Depreciation @ 3.37%	$ 24,086	$ 27,681	$ 31,762	$ 36,330	$ 41,385	$ 46,927	$ 52,956	$ 59,471	$ 66,473	$ 73,962	$ 81,938	$ 90,400	
Average Net Plant	$ 1,082,581	$ 1,252,319	$ 1,421,571	$ 1,590,336	$ 1,758,615	$ 1,926,406	$ 2,093,711	$ 2,260,529	$ 2,426,860	$ 2,592,705	$ 2,758,062	$ 2,922,933	
Return and Taxes @ 11.577%	$ 10,444	$ 12,082	$ 13,715	$ 15,343	$ 16,966	$ 18,585	$ 20,199	$ 21,808	$ 23,413	$ 25,013	$ 26,608	$ 28,199	$ 232,376

Total Year 2 Estimated Expenditures $ 1,311,068

SHF Exhibit No 12.xls

SHF Exhibit No. 13
Page 1 of 2

Appalachian Power and Wheeling Po.
Reliability Expenditures 2007
Total WV Distribution Asset Programs/Distribution Forestry O&M - 2007

2007

uns	Project Type	Project	(01) Jan Act $	(02) Feb Act $	(03) Mar Act $	1st Qtr	(04) Apr Act $	(05) May Act $	(06) Jun Act $	2nd Qtr	(07) Jul Act $	(08) Aug Act $	(09) Sep Act $	3rd Qtr	(10) Oct Act $	(11) Nov Act $	(12) Dec Act $	4th Qtr	Total Year	WV T&D Dec-07 YTD
AP WV	AICCB Asset Imp Circuit Insp/Rep	000005678 Ds-AP-WVirg-Al Ckt Inspections	36,627	45,818	24,580	107,025	5,675	1,623	4,867	12,165	1,726	2,168	(604)	3,279	2,059	14,804	53,587	70,450	192,919	
	AIMCB Asset Improvement - Other	DAPWVCAPC AP/WV/Dist Capacitor Program							92	92	766	440		1,206	41	180	2	223	1,521	
	AINCB Asset Imp Network Maintenance	DP6NW041A AP-Huntington Protector Fuse		211		211				0				0				0	211	
		EDN102230 Ds-Ap-Charleston Network Maint	10,703	13,902	10,074	34,679	2,563	6,051	4,999	13,613	4,925	21,342	4,205	30,472	3,086	4,801	21,287	29,174	107,938	
		EDN102231 Ds-Ap-Huntington Network Maint	(288)	845		557	403	2,868	33	3,304	2,870	1,853	419	5,152	3,209	1,920	1,375	6,504	15,517	
	AINCB Asset Imp Network Maintenance	SUB-TOTAL	10,415	14,958	10,074	35,447	2,966	8,919	5,032	16,917	7,795	23,205	4,624	35,624	6,295	6,721	22,662	35,678	123,666	
	AIPCB Asset Imp Pole Replacement	000005642 Ds-AP-WVirg-Al Pole Replace	2,605	15,805	116,565	135,175	(35,927)	24,677	11,805	555	61,162	29,615	2,785	93,532	29,700	7,004	5,238	41,942	271,204	
	AIRCB Asset Imp Pole Reinforcement	000005636 Ds-AP-WVirg-Al Pole Reinforce		34		34			105	105	114	715		829				0	968	
	AISCB Asset Imp Sectionalizing Prog.	000005691 AP/WVirg-Sectionalizing Prog	3,517	2,730	2,211	8,458	1,176	(171)	690	1,695	(3,161)	(339)	534	(2,966)	4,124	21,221	(1,323)	24,022	31,209	
	AIUCB Asset Imp URD	000005678 Ds-AP-WVirg-Al Urd Program	5,229	444	14	5,687	26	69		95				0				0	5,782	
	ANINC Animal Mitigation	000006097 Ds AP WVirg-Animal Mitigation	322	5,268	8,276	13,865	369	4		373				0				0	14,238	
	ARCCB Asset Imp Line Reclosers	000005667 Ds-AP-WVirg-Al Recloser Repl	1,882	1,408	2,080	5,370	471	(1,020)	2,768	2,219	(173)	(9,373)	(541)	(10,087)	696	492	765	1,953	(545)	
	POLNC Pole Inspection	000008103 AP WVirg-Inspect Poles	135	38	1,065	1,238	2,100	12,846		14,946		3,692		3,692				0	19,876	
	SWOCB Asset Imp Small Wire OH	000005647 Ds-AP-WVirg-Small Wire Repl Ov	1,205	4,814	5,260	11,079	525			525			213	213	(213)	8,196	288	8,271	20,088	
	SWUCB Asset Imp Small Wire UG	000005654 Ds-AP-WVirg-Small Wire Rep Urd	4,262			4,262		(142)		(142)	5			5				0	4,125	
	Asset Programs	TOTAL	66,399	91,117	170,124	327,640	(22,619)	46,805	25,359	49,545	68,223	50,113	6,991	125,327	42,702	58,618	61,219	182,539	685,051	
	RWWCG Forestry ROW Widening	000009188 Forestry AP WV D Base R W	1,276,285	929,538	864,298	3,070,121	1,093,279	1,236,119	1,197,343	3,526,741	1,380,461	1,092,485	992,970	3,465,916	1,173,048	949,298	1,554,815	3,677,161	13,739,939	
	TCRCS Targeted Circuit Reliab CapStd	000007509 Targeted AP WV D Reliability	42,849	3,343	(3,343)	42,849		2,416	(2,416)	0				0				0	42,849	
		000014721 AP/WV/Targt Ckt Reliability 07													833	(833)	1,719	1,719	1,719	
	Distribution Forestry	TOTAL	1,319,134	932,881	860,955	3,112,970	1,093,279	1,238,535	1,194,927	3,526,741	1,380,461	1,092,485	992,970	3,465,916	1,173,881	948,465	1,556,534	3,678,880	13,784,507	
	Total AP WV		1,385,533	1,023,998	1,031,079	3,440,610	1,070,660	1,285,340	1,220,286	3,576,286	1,448,684	1,142,598	999,961	3,591,243	1,216,583	1,007,083	1,637,753	3,861,419	14,469,558	14,469,558
Wheeling	AICCB Asset Imp Circuit Insp/Rep	EDN100578 Ds-Wp-Al Ckt Inspections	6,184	4,207	1,377	11,768	(138)			(135)		16	678	694	11,984	5,092	1,400	18,476	31,000	
	AINCB Asset Imp Network Maintenance	EDN102229 Ds-Wp-Wheeling Network Maint	5,093	16,788	22,124	44,005	8,509	(23,812)	249	(15,054)	1,416	5,086	4	6,506		3,060	2,108	5,168	40,627	
	AIPCB Asset Imp Pole Replacement	EDN014679 Ds-Wp-Al Pole Replacement	973	3,941	3,201	8,115	5,780	1,406	18,246	25,432	11,132	14,812	17,007	42,951	6,573	2,297	1,460	10,330	86,828	
	AIRCB Asset Imp Pole Reinforcement	EDN014672 Ds-Wp-Al Pole Reinforcement	252	3,034	120	3,406	(3,154)			(3,154)				0				0	252	
	AISCB Asset Imp Sectionalizing Prog.	000004646 WP/Sectionalizing Program	324	289	465	1,078	0			0				0				0	1,078	
	AIUCB Asset Imp URD	EDN100224 Ds-Wp-Al Urd Program				0	56	1	35	92			203	203	2,263	5,537	2,092	9,892	10,247	
	ARCCB Asset Imp Line Reclosers	EDN014719 Ds-Wp-Al Recloser Replacement		105	216	321	37	1		36				0		43		43	402	
	Asset Programs		12,826	28,364	27,503	60,693	11,090	(22,404)	18,530	7,216	12,548	19,916	18,162	50,616	20,820	16,029	7,080	43,909	170,434	
																		0	0	
	RWWCG Forestry ROW Widening	000009655 Forestry WP D Base R W	107,724	68,282	89,271	265,277	149,340	127,499	316,279	593,118	16,739	85,691	67,111	169,541	66,609	1,118	18,330	86,057	1,113,993	
																		0	0	
	Total Wheeling		120,550	96,646	116,774	333,970	160,430	105,095	334,809	600,334	29,287	105,607	85,263	220,157	87,429	17,147	25,390	129,966	1,284,427	1,284,427

		19,630,992
WV Distribution Reliability O&M Plus Allocation of total APCo and WPCo Transmission Forestry O&M	80.25%	15,753,985
APCo and WPCo WV Distribution Reliability Direct Assignment	19.75%	3,877,007
Allocation to WV Retail of total APCo and WPCo Transmission Forestry O&M	100.00%	19,630,992

Case No. 2007-00522
March 18, 2008 Hearing
Supplemental Data Request
Item No. 3

Appalachian Power a[...]ling Power
Reliability Expenditures 2007
Total WV Transmission Forestry O&M - 2007

uris	Project		2007 (01) Jan Act $	(02) Feb Act $	(03) Mar Act $	1st Qtr	(04) Apr Act $	(05) May Act $	(06) Jun Act $	2nd Qtr	(07) Jul Act $	(08) Aug Act $	(09) Sep Act $	3rd Qtr	(10) Oct Act $	(11) Nov Act $	(12) Dec Act $	4th Qtr	Total Year
	000009163	Forestry AP VA D Base R W		5,083	(4,696)	387	68	(1)	300	367		578	288	866	228	3,345		3,571	5,191
	000009168	Forestry AP WV D Base R W				0	17,277	3,094	(12,194)	8,177				0	2,147			2,147	10,324
	000010375	Forestry AP/VA T NERC	255,225	15,125	97,603	367,953	54,943	80,840	83,837	219,620	125,124	138,769	174,698	438,611	200,843	266,094	85,912	552,849	1,579,033
	000010376	Forestry AP/WV T NERC	103,086	70,967	62,880	236,932	46,686	75,166	142,138	263,990	186,266	346,314	264,353	796,933	383,881	176,284	34,231	594,396	1,892,251
	000012894	Forestry AP/WV T non-NERC	166,517	107,545	112,626	386,688	120,930	223,455	234,150	578,535	399,518	304,813	575,332	1,279,663	219,997	(3,535)	4,899	221,361	2,466,247
	000012895	Forestry AP/VA T non-NERC	331,301	135,324	433,647	900,272	129,268	206,859	142,780	478,907	159,322	82,109	164,533	405,964	468,971	28,485	7,632	505,088	2,290,231
otal APCo			856,128	334,044	702,060	1,892,232	369,172	589,413	591,011	1,549,596	870,230	872,603	1,179,204	2,922,037	1,276,065	470,673	132,674	1,879,412	8,243,277
Vheeling	000010379	Forestry WP Target T CKT	162	(60)	14,133	14,235	9,787	(1,900)	(606)	7,281	4,292	2,419	1,541	8,252	112,759	15,434	808	129,001	158,769
	000012908	Forestry WP T non-NERC	10,847	15,479	3,156	29,482	8,020	2,705	(354)	10,371	2,000	4,158		6,158	22,953			22,953	68,954
Vheeling			11,009	15,419	17,289	43,717	17,807	805	(960)	17,652	6,292	6,577	1,541	14,410	135,712	15,434	808	151,954	227,733
			867,137	349,463	719,349	1,935,949	386,979	590,218	590,051	1,567,248	876,522	879,180	1,180,745	2,936,447	1,411,777	486,107	133,482	2,031,366	8,471,010

Appalachian Power and Wheeling Powe
Reliability Expenditures 2007
Total WV Distribution Asset Programs/Distribution Forestry O&M - 2007

uis	Project Type		Project		(01) Jan Act $	(02) Feb Act $	(03) Mar Act $	1st Qtr	(04) Apr Act $	(05) May Act $	(06) Jun Act $	2nd Qtr	(07) Jul Act $	(08) Aug Act $	(09) Sep Act $	3rd Qtr	(10) Oct Act $	(11) Nov Act $	(12) Dec Act $	4th Qtr	Total Year	WV T&D Dec-07 YTD
					2007																	
AP WV	AICCB	Asset Imp Circuit Insp/Rep	000005678	Ds-AP-WVirg-AI Ckt Inspections	36,627	45,818	24,580	107,025	5,675	1,823	4,867	12,165	1,725	2,156	(604)	3,279	2,059	14,804	53,587	70,450	192,919	
	AIMCB	Asset Improvement - Other	DAPWVCAPC	AP/WV/Dist Capacitor Program							92	92	768	440		1,206	41	180	2	223	1,521	
	AINCB	Asset Imp Network Maintenance	DP6NW041A	AP-Huntington Protector Fuse		211		211				0				0				0	211	
			EDN102230	Ds-Ap-Charleston Network Maint	10,703	13,902	10,074	34,679	2,563	6,051	4,999	13,613	4,925	21,342	4,205	30,472	3,086	4,601	21,287	29,174	107,938	
			EDN102231	Ds-Ap-Huntington Network Maint	(288)	845		557	403	2,868	33	3,304	2,870	1,863	419	5,162	3,209	1,920	1,375	6,504	15,517	
	AINCB	Asset Imp Network Maintenance		SUB-TOTAL	10,415	14,958	10,074	35,447	2,966	8,919	5,032	16,917	7,795	23,205	4,624	35,624	6,295	6,721	22,662	35,678	123,666	
	AIPCB	Asset Imp Pole Replacement	000005642	Ds-AP-WVirg-AI Pole Replace	2,805	16,605	116,565	136,176	(35,827)	24,677	11,605	655	81,162	29,616	2,768	93,832	29,700	7,004	5,238	41,942	271,204	
	AIRCB	Asset Imp Pole Reinforcement	000005638	Ds-AP-WVirg-AI Pole Reinforce		34		34			105	105	114	715		828				0	968	
	AISCB	Asset Imp Sectionalizing Prog.	000005691	AP/WVirg-Sectionalizing Prog	3,517	2,730	2,211	8,458	1,176	(171)	690	1,695	(3,101)	(339)	534	(2,866)	4,124	21,221	(1,323)	24,022	31,209	
	AIUCB	Asset Imp URD	000005676	Ds-AP-WVirg-AI Urd Program	5,229	444	14	5,687	28	69		95				0				0	5,782	
	ANINC	Animal Mitigation	000006097	Ds AP WVirg-Animal Mitigation	322	6,268	8,275	13,865	369	4		373				0				0	14,238	
	ARCOB	Asset Imp Line Reclosers	000005687	Ds-AP-WVirg-AI Recloser Repl	1,882	1,408	2,080	5,370	471	(1,020)	2,768	2,219	(173)	(9,373)	(641)	(10,087)	696	492	765	1,953	(545)	
	POLNC	Pole Inspection	000006103	AP WVirg-Inspect Poles	135	38	1,065	1,238	2,100	12,840		14,946		3,692		3,692				0	19,876	
	SWOCB	Asset Imp Small Wire OH	000005647	Ds-AP-WVirg-Small Wire Repl Ov	1,205	4,614	5,260	11,079	525			525			213	213	(213)	8,198	288	8,271	20,088	
	SWUCB	Asset Imp Small Wire UG	000005654	Ds-AP-WVirg-Small Wire Rep Urd	4,262			4,262		(142)		(142)	5			5				0	4,125	
	Asset Programs			TOTAL	66,399	91,117	170,124	327,640	(22,619)	46,805	25,359	49,545	68,223	80,113	6,991	125,327	42,702	58,618	81,219	182,539	685,051	
	RWWCG	Forestry ROW Widening	000009168	Forestry AP WV D Base R W	1,276,285	929,538	864,298	3,070,121	1,093,278	1,236,119	1,197,343	3,526,741	1,380,461	1,092,485	992,970	3,465,916	1,173,048	949,298	1,554,815	3,677,161	13,739,939	
	TCRCS	Targeted Circuit Reliab CapStd	000007609	Targeted AP WV D Reliability	42,849	3,343	(3,343)	42,849		2,416	(2,416)	0				0				0	42,849	
			000014721	AP/WV/Targt Ckt Reliability 07													833	(833)	1,719	1,719	1,719	
	Distribution Forestry			TOTAL	1,319,134	932,881	860,955	3,112,970	1,093,279	1,238,535	1,194,927	3,526,741	1,380,461	1,092,485	992,970	3,465,916	1,173,881	948,465	1,556,534	3,678,880	13,784,507	
	Total AP WV				1,385,533	1,023,998	1,031,079	3,440,610	1,070,660	1,285,340	1,220,286	3,576,286	1,448,684	1,142,698	999,961	3,591,243	1,216,583	1,007,083	1,637,753	3,861,419	14,469,558	14,469,558
Wheeling	AICCB	Asset Imp Circuit Insp/Rep	EDN100576	Ds-Wp-AI Ckt Inspections	6,184	4,207	1,377	11,768	(138)			(138)		16	878	894	11,984	5,092	1,400	18,476	31,000	
	AINCB	Asset Imp Network Maintenance	EDN102229	Ds-Wp-Wheeling Network Maint	5,093	16,788	22,124	44,005	6,609	(23,812)	249	(16,054)	1,416	5,088	4	6,508		3,080	2,108	5,168	40,627	
	AIPCB	Asset Imp Pole Replacement	EDN014679	Ds-Wp-AI Pole Replacement	973	3,941	3,201	8,115	5,780	1,408	18,246	25,432	11,132	14,812	17,007	42,951	8,673	2,297	1,460	10,330	86,828	
	AIRCB	Asset Imp Pole Reinforcement	EDN014672	Ds-Wp-AI Pole Reinforcement	262	3,034	120	3,408	(3,154)			(3,154)				0				0	252	
	AISCB	Asset Imp Sectionalizing Prog.	000004646	WP/Sectionalizing Program	324	289	465	1,078	0			0				0				0	1,078	
	AIUCB	Asset Imp URD	EDN100224	Ds-Wp-AI Urd Program				0	56	1	35	92			263	263	2,263	5,637	2,092	9,992	10,247	
	ARCOB	Asset Imp Line Reclosers	EDN014719	Ds-Wp-AI Recloser Replacement		105	216	321	37	1		38				0		43		43	402	
	Asset Programs				12,828	28,364	27,603	68,693	11,090	(22,404)	18,530	7,216	12,548	19,916	18,152	50,616	20,820	16,029	7,060	43,909	170,434	
																				0	0	
	RWWCG	Forestry ROW Widening	000009655	Forestry WP D Base R W	107,724	68,282	89,271	265,277	149,340	127,489	316,279	593,118	16,739	85,691	67,111	169,541	66,609	1,118	18,330	86,057	1,113,993	
																				0	0	
	Total Wheeling				120,550	96,646	116,774	333,970	160,430	105,095	334,809	600,334	29,287	105,607	85,263	220,157	87,429	17,147	25,390	129,966	1,284,427	1,284,427

WV Distribution Reliability O&M Plus Allocation of total APCo and WPCo Transmission Forestry O&M		19,630,992
APCo and WPCo WV Distribution Reliability Direct Assignment	80.25%	15,753,985
Allocation to WV Retail of total APCo and WPCo Transmission Forestry O&M	19.75%	3,877,007
	100.00%	19,630,992

Case No. 2007-00522
March 18, 2008 Hearing
Supplemental Data Request
Item No. 3

Appalachian Power & ..eeling Power
Reliability Expenditures 2007
Total WV Transmission Forestry O&M - 2007

Juris	Project		2007 (01) Jan Act $	(02) Feb Act $	(03) Mar Act $	1st Qtr	(04) Apr Act $	(05) May Act $	(06) Jun Act $	2nd Qtr	(07) Jul Act $	(08) Aug Act $	(09) Sep Act $	3rd Qtr	(10) Oct Act $	(11) Nov Act $	(12) Dec Act $	4th Qtr	Total Year
	000009163	Forestry AP VA D Base R W		5,083	(4,696)	387	68	(1)	300	367		578	288	866	226	3,345		3,571	5,191
	000009168	Forestry AP WV D Base R W				0	17,277	3,094	(12,194)	8,177				0	2,147			2,147	10,324
	000010375	Forestry AP/VA T NERC	265,225	15,125	97,603	367,953	54,943	80,840	83,837	219,620	125,124	138,789	174,698	438,611	200,843	266,094	85,912	552,849	1,579,033
	000010376	Forestry AP/WV T NERC	103,085	70,967	62,880	236,932	46,666	75,166	142,138	263,990	186,266	346,314	264,353	796,933	383,881	176,284	34,231	594,396	1,892,251
	000012894	Forestry AP/WV T non-NERC	166,517	107,545	112,626	386,688	120,930	223,455	234,150	578,535	399,518	304,813	576,332	1,279,663	218,997	(3,535)	4,899	221,361	2,466,247
	000012895	Forestry AP/VA T non-NERC	331,301	135,324	433,647	900,272	129,288	206,859	142,780	478,907	159,322	82,109	164,533	405,964	468,971	28,485	7,632	505,088	2,290,231
Total APCo			856,128	334,044	702,060	1,892,232	369,172	589,413	591,011	1,549,596	870,230	872,603	1,179,204	2,922,037	1,276,065	470,873	132,674	1,879,412	8,243,277
Wheeling	000010379	Forestry WP Target T CKT	162	(60)	14,133	14,235	9,767	(1,900)	(606)	7,261	4,292	2,419	1,541	8,252	112,759	15,434	808	129,001	158,769
	000012908	Forestry WP T non-NERC	10,847	15,479	3,156	29,482	8,020	2,705	(354)	10,371	2,000	4,158		6,158	22,953			22,953	68,964
Wheeling			11,009	15,418	17,289	43,717	17,807	805	(960)	17,652	6,292	6,577	1,541	14,410	135,712	15,434	808	151,954	227,733
			867,137	349,463	719,349	1,935,949	386,979	590,218	590,051	1,567,248	876,522	879,180	1,180,745	2,936,447	1,411,777	486,107	133,482	2,031,366	8,471,010

APPALACHIAN POWER COMPANY and WHEELING POWER COMPANY COMBINED
WEST VIRGINIA P.S.C. QUARTERLY REVIEW
CALCULATION OF RETURN ON RATE BASE AND COMMON EQUITY
BASED ON ANNUAL AVERAGE VALUES
ACTUAL AS OF DECEMBER 31, 2007

	Amount Outstanding ($000)	Percent %	Cost Rate %	Weighted Cost Rate %
Long-term Debt	2,764,767	54.95%	5.725%	3.146%
Short-term Debt	155,116	3.08%	5.729%	0.177%
Preferred Stock (Amount Outstanding Includes Issuance Premiums)	18,139	0.36%	4.352%	0.016%
Subtotal	2,938,022			3.338%
Common Equity:				
Common Stock	262,886			
Other Paid-in Capital	993,817			
Retained Earnings:				
Restricted for Bond Indentures	0			
All Other	836,512			
Total Common Equity	2,093,215	41.604%		
Total Capital	5,031,237	100%		

Operating Income (Statement 1)	$	161,140,899 #
Jurisdictional Rate Base (Statement 1)	÷	2,315,258,842
Earned Rate of Return		6.960%
Weighted Cost Rate - Debt & Preferred Stock	-	3.338%
Difference - Weighted Return on Common Equity		3.622%
Return on Common Equity: 3.622% ÷ 41.604%		8.705% #

Note:
Capital structure balances, cost rates and interest synchronization are based on annual average calculations.

Excludes the $4.782 million deferral of WV Reliability Costs Recorded in Dec 2007

Appalachian Power and Wheeling Power
Reliability Expenditures
Distribution / Transmission Assignment

O&M - Related Expenditures	2004	2007	Increase Expenditure (2)-(1)	Deferral Recovery Pro-rated (3)
	(1)	(2)	(3)	(4)
Test Year Distribution				
APCO-WV	9,388,152	13,784,507		
WPCo	990,799	1,113,993		
	10,378,951	14,898,500	4,519,549	3,756,435
Asset Programs Distribution				
APCO-WV	997,240	685,051		
WPCo	419,853	170,434		
	1,417,093	855,485	(561,608)	(466,782)
Sub-Total Distribution	11,796,044	15,753,985	3,957,941	3,289,653
Test Year Transmission				
APCO-WV	2,012,401	3,702,336		
WPCo	69,091	174,671		
	2,081,492	3,877,007	1,795,515	1,492,347
Total O&M Expenditures	13,877,536	19,630,992	5,753,456	4,782,000

Kentucky Power Company

REQUEST

Please provide a copy (when issued) of the West Virginia Public Service Commission's Order regarding Appalachian Power Company's Expanded Net Energy Charge (ENEC).

RESPONSE

The Company will provide a copy of the West Virginia Public Service Commission's Order associated with the APCo's Expanded Net Energy Charge when available.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Please refer to Mr. Wagner's testimony, page 9, lines 12 through 20. If the Commission confirms that KPCo can include the Marginal Line Loss charges and credits recorded in Accounts 447207 and 4470208 in the monthly fuel adjustment clause calculations, how does the Company propose to show the charges and credits in the monthly fuel adjustment clause schedules? Please provide an example.

RESPONSE

Please see the attached page 2. The Company proposes to modify the monthly *Fuel Cost Schedule, Page 2 of 5, Section B, Purchases* to add a new line titled *Net Transmission Marginal Line Loss (Accounts 4470207 and 4470208).* Additionally, the Company proposes to temporarily add *Section H, Net Transmission Marginal Line Loss Adjustment* to show the adjustment of including the monthly average line loss amount associated with Accounts 4470207 and 4470408 for the five months June 2007 through October 2007.

Also attached is a revised Exhibit EKW-1 demonstrating the calculation of the monthly average amount to be included in Section H of the Fuel Cost Schedule, Page 2 of 5.

WITNESS: Errol K Wagner

KENTUCKY POWER COMPANY
FUEL COST SCHEDULE

Month Ended

A.	Company Generation			
	Coal Burned	(+)		
	Oil Burned	(+)		
	Gas Burned	(+)		
	Fuel (jointly owned plant)	(+)		
	Fuel (assigned cost during F. O.)	(+)		
	Fuel (substitute for F. O.)	(-)	______	
	Sub Total		______	
B.	Purchases			
	Net Transmission Marginal Line Loss (Accounts 4470207 and 4470208)	(+)		
	Net Energy Cost - Economy Purchases	(+)		
	Identifiable Fuel Cost - Other Purchases	(+)		*
	Identifiable Fuel Cost (substitute for F. O.)	(-)	______	
	Sub Total		______	
C.	Inter-System Sales Fuel Costs		______	*
	Sub Total		______	
D.	Total Fuel Cost (A + B - C)		______	
E.	Adjustment indicating the difference in actual fuel cost for the month of ______ and the estimated cost originally reported. ______ (actual) - ______ (est.)	=	______	
F.	Total Company Over or (Under) Recovery from Page 4, Line 12		______	
G.	Grand Total Fuel Cost (D + E - F)			
H.	** Net Transmission Marginal Line Loss Adjustment		$1,057,548	**
I.	Adjusted Grand Total Fuel Cost		______	

* Estimated - based on actual Kentucky generation unit costs in ______ /KWH

**Above charge is one fifth of the Net Transmission Marginal Line Loss Adjustment associated with Accts. 4470207 and 4470208 for the months June 2007 thru October 2007, pursuant to PSC Order in Case No. 2007-00522 dated __________, 2008.

Exhibit EKW - 1
Page 1 of 1
Revised March 28, 2008

Kentucky Power Company
Load Serving Entity (LSE)
Net Transmission Line Losses
For the Period June 2007 through January 2008

Ln No (1)	Month (2)	Year (3)		Charge Acct No. 4470207 (4)	Credit Acct No. 4470208 (5)	Net Monthly Amount (6)
1	June	2007		$2,092,442.32	($813,497.55)	$1,278,944.77
2	July	2007		$1,167,867.88	($422,027.01)	$745,840.87
3	August	2007		$2,946,027.74	($1,136,813.99)	$1,809,213.75
4	September	2007		$1,474,422.32	($501,783.14)	$972,639.18
5	October	2007		$1,489,944.20	($1,008,842.68)	$481,101.52
6	November	2007		$1,395,539.09	($631,058.03)	$764,481.06
7	December	2007		$1,886,026.49	($895,749.19)	$990,277.30
8	Sub Total	2007		$12,452,270.04	($5,409,771.59)	$7,042,498.45
9	January	2008		$2,397,326.54	($1,109,174.84)	$1,288,151.70
10	February	2008	*	$2,099,641.84	($954,271.72)	$1,145,370.12
11	Total			$16,949,238.42	($7,473,218.15)	$9,476,020.27

* Will be provided when available

12	*Sub Total*		$7,042,498.45
	Less:		
13	November	2007	$764,481.06
14	December	2007	$990,277.30
15	June - October 2007 5 Month Total		$5,287,740.09
16	Five Monthly Adjustments		$1,057,548.00