VERIFICATION

The undersigned, Andrew R. Carlin , being duly sworn, deposes and says he is the Director, Compensation and Executive Benefits, that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief.

Andrew R. Carlin

STATE OF OHIO	)
	) Case No. 2017-00179
COUNTY OF FRANKLIN	)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Andrew R. Carlin, this the 18th day of December 2017.

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2021

Notary Public

My Commission Expires: October 1st 2021

VERIFICATION

The undersigned, Zachary C Miller, being duly sworn, deposes and says he is a Corporate Finance Analyst Principal for American Electric Power that he has personal knowledge of the matters set forth in the forgoing data requests and the information contained therein is true and correct to the best of his information, knowledge and belief

Z Mil

Zachary C Miller

STATE OF OHIO	)	
	)	CASE NO. 2017-00179
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Zachary C Miller, this the 13th day of December 2017.

Notary Public

My Commission Expires:

NOTARIAL SEAL STATE OF OHIO

David C. House, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

VERIFICATION

The undersigned, Tyler H Ross being duly sworn, deposes and says he is the Director Regulatory Accounting Services for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Tyler H Ross

Tyler H Ross

STATE OF OHIO)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tyler H Ross, this the 19th day of December 2017.

S. Smithhisler

Notary Public

My Commission Expires: 04/29/19

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Manager, Regulatory Pricing and Analysis that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief.

Alex E. Vaughan

STATE OF OHIO	)	
	)	Case No. 2017-00179
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, this the 15 day of December 2017.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Princess M. Brown
Notary Public, State of Ohio
My Commission Expires 04-19-2020

My Commission Expires: 4/19/2020

VERIFICATION

The undersigned, Amy J. Elliott, being duly sworn, deposes and says she is a Regulatory Consultant Principal for Kentucky Power Company, that she has personal knowledge of the matters set forth in the forgoing data responses and that the information contained therein is true and correct to the best of her information, knowledge, and belief

Amy J. Elliott

Amy J. Elliott

COMMONWEALTH OF KENTUCKY)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Amy J. Elliott, this 20th day of December 2017.

Judy K Rosquist

Notary Public

Notary ID Number: 571144

My Commission Expires: January 23, 2021

VERIFICATION

The undersigned, Brad N Hall being duly sworn, deposes and says he is the External Affairs Manager, for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Brad N Hall

COMMONWEALTH OF KENTUCKY)
) Case No. 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brad N Hall, this the 19 day of December 2017.

Trisha M. Young Blum
Notary Public

Notary ID: 530202

My Commission Expires: 3-18-19

COMMONWEALTH OF KENTUCKY
TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

VERIFICATION

The undersigned, Matthew J Satterwhite, being duly sworn, deposes and says he is the President and Chief Operating Officer for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief.

Matthew J Satterwhite

COMMONWEALTH OF KENTUCKY)
) Case No. 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Matthew J. Satterwhite, this the 19 day of December 2017.

Trisha M. Young Blum
Notary Public

Notary ID: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

VERIFICATION

The undersigned, Stephen L. Sharp, being duly sworn, deposes and says he is a Regulatory Consultant, for Kentucky Power Company and that he has personal knowledge of the matters set forth in the data responses and the information contained therein is true and correct to the best of his information, knowledge and belief

Stephen L. Sharp

COMMONWEALTH OF KENTUCKY)
) 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stephen L Sharp, this the 20th day of December 2017.

Judy K Rosquist
Notary Public

Notary ID Number: 571144

My Commission Expires: January 23, 2021

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 20th day of December 2017.

Judy K Rosquist

Notary Public

ID# 571144

My Commission Expires January 23, 2021

DATA REQUEST

KPSC_PH_001 Provide the following information concerning Kentucky Power and its affiliated service company for the test year:
a. A schedule detailing the costs directly charged to the service company and costs allocated to the service company by Kentucky Power. Indicate the accounts in which these costs were originally recorded by Kentucky Power. For costs that are allocated, include a description of the allocation factors utilized.
b. A schedule detailing the costs directly charged to Kentucky Power and costs allocated by the service company to Kentucky Power. Indicate the Kentucky Power accounts in which these costs were recorded. For costs that are allocated, include a description of the allocation factors utilized.

RESPONSE

This question appears to be a duplicate of KPSC 1-42. The response below is the same response as provided to KPSC 1-42.

a. During the test year, Kentucky Power directly billed $363,275.58 to AEP Service Corporation for costs related to Kentucky Power buildings partially occupied by AEPSC employees. Kentucky Power recorded the original transactions in various accounts, including (but not limited to) depreciation, property tax and building maintenance. When the costs are billed, Kentucky Power records revenue in Account 454 (Rent from Electric Property, Affiliated) and AEPSC records expense to Account 931 (Rents – Real Property, Associated).

b. Please refer to Section II, Exhibit U of the Company's application for costs directly charged to and allocated by AEPSC to Kentucky Power for the requested information. Additionally, as part of this response, please reference KPCO_SR_KPSC_1_73_Attachment100_Exhibit_U.xls, which is the excel version to Exhibit U provided in response to KPSC 1-73. It is provided here for ease of reference.

Witness: Tyler H. Ross

DATA REQUEST

KPSC_PH_002 Provide the following information concerning the al location of American Electric Power ("AEP") and AEP Service Company ("AEPSC") costs to Kentucky Power for the test year:
a. The total dollar amount being allocated to Kentucky Power from al l sources.
b. The percentage of AEP's total costs allocated to all subsidiaries represented by the costs allocated to Kentucky Power.
c. By cost category, the dollar amounts allocated from AEP and AEPSC to Kentucky Power, including the following. Refer to the Appendix to this request for an example of the information requested.
1) The total amount to be allocated;
2) Allocation methods applied;
3) Reference allocation number;
4) Weighted factor of each allocation method and how that weighted factor value was determined (formulaically and descriptively);
5) The resulting percentage used to allocate Kentucky Power's share of the total dollars to be allocated; and
6) The actual numbers used to develop the percentages and the allocated dollars.

RESPONSE

AEP Service Corporation (AEPSC) is a legal entity and subsidiary of AEP. Through its employees and services provided by outside vendors, AEPSC provides services at cost to various AEP subsidiaries. When the services provided by AEPSC are for the benefit of a single subsidiary, the cost of those services is allocated to the benefiting AEP subsidiary(ies) in accordance the AEPSC Cost Allocation Manual ("CAM").

FERC regulates affiliated AEPSC transactions under the 2005 Public Utility Holding Company Act and the Federal Power Act. FERC adopted AEPSC's allocators that are set forth in the CAM. The December 31, 2016 CAM is included in Schedule II, Exhibit A of the Company's Application.

a. During the test year, the total amount billed to Kentucky Power from AEPSC was $58,273,985. Of this billed amount, $22,930,024 was directly billed to Kentucky Power and $35,343,962 was allocated to Kentucky Power from AEPSC. Please reference the Summary Tab of KPCO_R_KPSC_PHDR_2_Attachment1.xlsx for the formula calculations per Staff's Appendix A sample.

Further, a portion of the $58,273,985 billed to Kentucky Power by AEPSC was subsequently billed by Kentucky Power to Wheeling Power Company, a 50% Joint Owner of the Mitchell

Plant. For the test year ended February 28, 2017, Kentucky Power billed Wheeling Power $6,933,267. The net amount for the test year included in the cost of service was $51,340,718.

b. During the test year, the total amount allocated by AEPSC to all affiliates was $826,821,340. Of this amount , Kentucky Power was allocated $35,343,962, which equals approximately 4.3%. Please refer to the Summary Tab of KPCO_R_KPSC_PHDR_2_Attachment1.xlsx for the calculation.

c. (1 thru 5) - Please refer to KPCO_R_KPSC_PHDR_2_Attachment1.xlsx for the requested information.

c. (6) - Please refer to the Company's response to KPSC_PH_003 and KPCO_R_KPSC_PH_3_Attachment1.xlsx for the requested information.

Witness: Tyler H. Ross

DATA REQUEST

KPSC_PH_003 Provide the amount of and supporting calculations for costs allocated by AEPSC to Kentucky Power during the test year in Excel spreadsheet format with all formulas intact and unprotected, and all rows and columns fully accessible.

RESPONSE

All AEPSC transactions are accounted for through a work order system. Expenditures for support services are accumulated in work orders and are billed to the company benefiting from the service. Each work order designates the company or companies to be billed and the method of allocation to share costs among the companies. Each work order has a pre-established benefiting location, which can be one or a combination of business units. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. This helps facilitate both a clearer understanding of the specific service provided and the recording of these charges on the benefiting companies' books.

The costs for services benefiting only one company are directly assigned and are billed 100% to that company. AEPSC employees directly assign costs on time and expense reports to the maximum extent practicable. Certain costs, however, are incurred to perform services that benefit more than one company. The costs for these services are allocated to the benefiting companies using one of the active AEPSC allocation factors. The allocation factor for any given cost is selected for use because it best reflects the cost driver associated with the service provided. In accordance with FERC regulations, services are billed by AEPSC at cost.

The allocation factors used to bill Kentucky Power and AEPSC's other utility affiliates for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission pole miles, number of invoices, and other factors as shown in section 99-00-04 of the Cost Allocation Manual provided in Section II, Exhibit A of Kentucky Power's Application. The data inputted into these formulas are updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility.

A volume-driven formula is used in all cases where the cost driver is volume based and the data is available. For example, in allocating costs for processing accounts payable, the number of vendor invoice payments is used; and for the overall management of the customer call centers, AEPSC uses the number of customer calls received.

If a work order does not have a direct volume-based cost driver, the most representative factor for the service provided is used. For example, for administering the employee benefit plans, number of employees is used; for managing and dispatching the transmission system, number of transmission pole miles is used. The allocation factors are designed to ensure that the charges are in proportion to the benefits received by the benefiting companies.

Please see KPCO_R_KPSC_PH_3_Attachment1.xlsx for the statistical values used for each allocation factor during the test year, by month.

Witness: Tyler H. Ross

DATA REQUEST

KPSC_PH_004 Provide a copy of the Rockport Generation Plant Unit Power Agreement.

RESPONSE

Please refer to KPCO_R_KPSC_PH_4_Attachment1.pdf for the requested information. Kentucky Power also provided a copy of the Rockport Unit Power Agreement in response to AG 1-2.

Witness: Matthew J. Satterwhite

AEP Generating Company
FERC Rate Schedule No. 2
Unit Power Service
to
Kentucky Power Company

Tariff Submitter: AEP Generating Company
FERC Tariff Program Name: FPA Electric
Tariff Title: RS and SA
Tariff Record Proposed Effective Date: December 31, 2012
Tariff Record Title: Kentucky Power Company Unit Power Agreement
Option Code: A

UNIT POWER AGREEMENT

THIS AGREEMENT dated as of August 1, 1984 by and between KENTUCKY POWER COMPANY ('KEPCO") and AEP GENERATING COMPANY ("AEGCO").

WITNESSETH:

WHEREAS, AEGCO, a subsidiary company of American Electric Power Company, Inc. ("AEP") under the Public Utility Holding Company Act of 1935 (the "1935 Act"), is part owner of the Rockport Steam Electric Generating Plant presently under construction at a site along the Ohio River near the Town of Rockport, Indiana, which will consist of two 1,300,000-kilowatt fossil-fired steam electric generating units and associated equipment and facilities (the "Rockport Plant"), the first unit ("Unit No. 1") of which is presently expected to be placed in commercial operation on or about December 1, 1984 and the second unit ("Unit No. 2") of which is presently expected to be placed in commercial operation in 1988; and

WHEREAS, AEGCO entered into an Owners' Agreement, dated March 31, 1982, as amended, (the "Owners' Agreement"), with Indiana & Michigan Electric Company ("IMECO") and KEPCO, other subsidiary companies of AEP under the 1935 Act, pursuant to which AEGCO and KEPCO planned to acquire 35% and 15% undivided ownership interests from IMECO respectively, as tenants in common without right of partition, in the Rockport Plant which, upon completion of the construction of Unit No. 1, is thereafter to be operated as a part of the interconnected, integrated electric system comprising the American Electric Power System (the "AEP System"); and

WHEREAS, the Owners' Agreement, as amended, provides that if KEPCO is unable to obtain timely regulatory approval to acquire and directly own its intended 15% ownership interest in the Rockport Plant by the date test power and energy becomes available from Unit No. 1, which is anticipated to occur not earlier than September 1, 1984, or, if such regulatory approval is limited or restricted in any manner as to make performance by KEPCO impossible, impractical or uneconomic, then, AEGCO may and proposes to acquire the 15% undivided ownership interest intended for KEPCO; and

WHEREAS, if AEGCO acquires the 15% undivided ownership interest intended for KEPCO then AEGCO proposes, upon completion of the construction of Unit No. 1 and the completion thereafter of the construction of Unit No. 2, to make available to KEPCO, pursuant to this agreement, 30% of the available power (and the energy associated therewith) to which AEGCO shall from time to time be entitled at the Rockport Plant, which amount is equivalent to the 15% ownership interest intended for KEPCO; and

WHEREAS, IMECO proposes to complete the construction of the Rockport Plant pursuant to the provisions of the Owners' Agreement, as amended, and, upon completion of such construction, to operate the Rockport Plant pursuant to an operating agreement entered into by IMECO, AEGCO and KEPCO in accordance with the Owners' Agreement;

NOW, THEREFORE, in consideration of the terms and of the agreements hereinafter set forth, the parties hereto agree with each other that if AEGCO acquires the 15% undivided ownership interest intended for KEPCO then:

1.1 AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 of this agreement, make available, or cause to be made available, to KEPCO 30% of the power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant.

1.2 KEPCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.2 of this agreement, be entitled to receive 30% of the power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant and KEPCO agrees to pay to AEGCO in consideration for the right to receive that 30% of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant those amounts which IMECO would have paid AEGCO under the terms of the IMECO-AEGCO Unit Power Agreement, for KEPCO's entitlement as defined in this agreement. KEPCO shall commence the payment of such amounts to AEGCO on the earlier of the following dates: (i) June 30, 1985 and, (ii) the date of commercial operation of Rockport Unit No. 1.

2.1 The performance of the obligations of AEGCO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary to permit AEGCO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities at the time necessary to permit the completion by IMECO of the construction of the Rockport Plant, the operation of the Rockport Plant, and for AEGCO to make available to KEPCO 30% of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant. AEGCO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities.

2.2 The performance of the obligations of KEPCO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities necessary at the time to permit KEPCO to perform its duties and obligations hereunder, *including the receipt and continued effectiveness of all authorizations by governmental* regulatory authorities necessary at the time to permit KEPCO to pay to AEGCO in consideration for the right to receive 30% of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant the charges provided for in Section 1.2 of this agreement. KEPCO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities. KEPCO shall, to the extent permitted by law, be obligated to perform its duties and obligations hereunder, subject to then applicable provisions of this Section 2.2, (a) whether or not AEGCO shall have received all authorizations of governmental regulatory authorities necessary to permit AEGCO to perform its duties and obligations hereunder, (b) whether or not such authorizations, or any such authorization, shall at any time in question be in effect, and (c) so long as AEGCO and KEPCO shall continue to be subsidiary companies of AEP (as said term is defined in Section 2(a)(8) of the 1935 Act) or a successor thereto, whether or not, at any time in question, KEPCO shall have performed its duties and obligations under this agreement. In the event that either AEGCO or KEPCO shall cease to be such a subsidiary company, then and thereafter KEPCO shall not be relieved of its obligation to make payments pursuant to Section 1.2 of this agreement by reason of the failure of AEGCO to perform its duties and obligations hereunder occasioned by Act of God, fire, flood, explosion, strike, civil or military authority, insurrection, riot, act of the elements, failure of equipment, or for any other cause beyond the control of AEGCO; provided that, in any such event, AEGCO shall use its best efforts to put itself in a position where it can perform its duties and obligations hereunder as soon as is reasonably practicable.

3. To the extent that it may legally do so, KEPCO and AEGCO each hereby irrevocably waives any defense based on the adequacy of a remedy at law which may be asserted as a bar to the remedy of specific performance in any action brought against it for specific performance of this agreement by KEPCO, by AEGCO, or by a trustee under any mortgage or other debt instrument which KEPCO or AEGCO may, subject to requisite regulatory authority, enter into, or by any receiver or trustee appointed for KEPCO or AEGCO under the bankruptcy or insolvency laws of any jurisdiction to which KEPCO or AEGCO is or may be subject; provided, however, that nothing herein contained shall be deemed to constitute a representation or warranty by KEPCO or AEGCO that the respective obligations of KEPCO or AEGCO under this agreement are, as a matter of law, subject to the equitable remedy of specific performance.

4. KEPCO shall not be entitled to set off against any payment required to be made by KEPCO under this agreement (i) any amounts owed by AEGCO to KEPCO or (ii) the amount of any claim by KEPCO against AEGCO. The foregoing, however, shall not affect in any other way the rights and remedies of KEPCO with respect to any such amounts owed to KEPCO by AEGCO or any such claim by KEPCO against AEGCO.

5. The invalidity and unenforceability of any provision of this agreement shall not affect the remaining provisions hereof.

6. This agreement shall become effective with the date of commercial operation of Rockport Unit No. 1 and shall continue in effect through December 7, 2022.

7. This agreement shall be binding upon the parties hereto and their successors and assigns, but no assignment hereof, or of any right to any funds due or to become due under this agreement, shall in any event relieve either KEPCO or AEGCO of any of their respective obligations hereunder, or, in the case of KEPCO, reduce to any extent its entitlement to receive 30% of the power (and the energy associated therewith) available to AEGCO from time to time at the Rockport Plant.

8. The agreements herein set forth have been made for the benefit of KEPCO and AEGCO and their respective successors and assigns, and no other person shall acquire or have any right under or by virtue of this agreement.

9. KEPCO and AEGCO may, subject to the provisions of this agreement, enter into a further agreement or agreements between KEPCO and AEGCO setting forth detailed terms and provisions relating to the performance by KEPCO and AEGCO of their respective obligations under this agreement. No agreement entered into under this Section 9 shall, however, alter to any substantive degree the obligations of either party to this agreement in any manner inconsistent with any of the foregoing sections of this agreement.

10. KEPCO shall, at any time and from time to time, be entitled to assign all of its right, title and interest in and to all of the power (and the energy associated therewith) to which KEPCO shall be entitled under this agreement, but KEPCO shall not, by such assignment, be relieved of any of its obligations and duties under this agreement except through the payment to AEGCO, by or on behalf of KEPCO, of the amount or amounts which KEPCO shall be obligated to pay pursuant to the terms of this agreement.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be duly executed as of the day and year first above written.

AEP Generating Company

By ____________________________

Vice President

KENTUCKY POWER COMPANY

By ____________________________

President

RATE DESIGN

The total revenue requirement of AEGCO calculated pursuant to the IMECO-AEGCO Unit Power Agreement designated AEGCO FERC Rate Schedule No. 1 is designed to recover for AEGCO its total cost of providing power (and the energy associated therewith) available to AEGCO at the Rockport Plant.

DETERMINATION OF POWER BILL

In accordance with Section 1.3 of the Unit Power Agreement, I&M agrees to pay AEGCO in consideration for the right to receive all power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M), such amounts, less any amounts recovered by AEGCO from other sources, as shall be determined monthly as described below. Such amounts shall be calculated separately for Unit No. 1 (including Common Facilities) and for Unit No. 2. I&M shall then commence the payment of such amounts (power bill) on the earlier of the following dates: (i) June 30, 1985 and (ii) the date on which power including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant.

The power bill for Unit No. 1 (including Common Facilities) shall be calculated each month and shall reflect recovery only of those costs related to the plant in service. It shall consist of the sum of (a) a return on common equity, (b) a return on other capital, (c) recovery of operating expenses and (d) provision for federal income taxes as described below and as illustrated in the example attached.

(a) Return on Common Equity, which shall be equal to the product of (i) the amount of common equity outstanding at the end of the previous month, but not more than 40% of the capitalization of AEGCO at the end of the previous month; (ii) 1.0133 (12.16% annual rate) as described in Note 1 below; (iii) the Operating Ratio, as defined in Note 2 below; and (iv) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below, plus the product of (v) the amount of common equity in excess of 40% of the capitalization of AEGCO at the end of the previous month, if any such excess shall be determined; (vi) the weighted cost of debt outstanding at the end of the previous month; (vii) the Operating Ratio, as defined in Note 2 below; and (viii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, the amount of common equity shall be equal to the sum of the Common Stock (Accounts 201-203, 209, 210, 212, 214 and 217), Other Paid-In Capital (Accounts 207, 208, 211 and 213), and Retained Earnings (Accounts 215-216) outstanding at the end of the previous month. Total capitalization shall be equal to the sum of Long-term Debt (Accounts 221-226 including current maturities and unamortized debt premium and discounts), Short-Term Debt (Accounts 231 and 233), Preferred Stock (Accounts 204-206), and Common Equity less any Temporary Cash Investments, Special

Deposits and Working Funds (Accounts 132-134, 136, and 145) outstanding at the end of the previous month.

(b) Return on Other Capital, which shall be equal to the product of (i) the amount equal to the net interest expense associated with Long-Term and Short-Term Debt, net of any Temporary Cash Investments, Special Deposits and Working Funds, plus the preferred stock dividend requirement associated with the Preferred Stock outstanding at the end of the previous month; (ii) the Operating Ratio, as defined in Note 2 below; and (iii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, net interest expense shall be equal to the sum of (i) the amount of Long-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Long-Term Debt and (ii) the amount of Short-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Short-Term Debt, less (iii) the amount of Temporary Cash Investments, Special Deposits and Working Funds outstanding at the end of the previous month multiplied by the weighted cost of Long Term and Short-Term Debt combined determined pursuant to (i) and (ii) above.

(c) Recovery of Operating Expenses, excluding federal income taxes, which shall consist of provision for depreciation and amortization (Accounts 403-407, 411), including Asset Retirement Obligation (ARO) depreciation and accretion expenses (Accounts 403.1 and 411.10), taxes other than federal income taxes (Accounts 408-411) and operating and maintenance expenses associated with Unit No. 1 (including Common Facilities) offset by other operating revenues as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities (See Note 6). Recovery of expenses for test energy shall be limited to recovery of actual fuel expense as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities. Operating and maintenance expenses shall include, and reflect the recovery of, Steam Power Generation Expenses (Accounts 500-515 including lease rental payments recorded in Account 507), Other Power Supply Expenses (Accounts 555-557), Transmission Expenses (Accounts 560-574), Distribution Expenses (Accounts 580-598), Customer Accounts Expenses (Accounts 901-905), Customer Service and Informational Expenses (Accounts 906-910), Sales Expenses (Accounts 911-917) and Administrative and General Expenses (Accounts 920-933 and 935). Recovery of 501 fuel expenses shall be adjusted to reflect the deferral and/or feedback of unrecovered levelized fuel expenses as may be recorded on the Company's books or as is currently recorded on the books of I&M.

(d) Provision for Unit No. 1's (including Common Facilities) allocated share of net current and deferred federal income tax expense and investment tax credit included in operating income as determined by the Company in accordance with federal income tax law, SEC approved consolidated current tax allocation procedures, and FERC rules and regulations.

For purposes of computing federal income taxes, the interest expense deduction shall be equal to the sum of the net interest expense computed in accordance with paragraph (b) above plus the imputed interest expense associated with common equity that is in excess of 40% of AEGCO's net capitalization.

The power bill for Unit No. 2 shall be calculated in the same manner as described for Unit No. 1 above except that it shall reflect the Unit No. 2 Net In-Service Investment Ratio and those expenses associated with Unit No. 2.

Notes:

1. **Return on Equity**

The return on common equity allowance shall be based upon a rate of return of 12.16% as set forth in sub-paragraph (a) above.

In October of 1988, and every October thereafter for the effective duration of AEGCO's formula rate, any purchaser under AEGCO's two unit power agreements, any state regulatory commission having jurisdiction over the retail rates of purchasers under these agreements, or any other entity representing customers' interest, may file a complaint with the Commission with respect to the specified rate of return on common equity. If the Commission, in response to such a complaint, or on its own motion, institutes an investigation into the reasonableness of the specified return on common equity, such investigation shall be pursued under the special procedures set forth as follows:

A. The only issue to be addressed under these special procedures shall be the continued collection of the return on equity as incorporated in the formula rate; and

B. Refund will be due, should the return on equity, specified in the formula be found not just and reasonable, dating from the first day of January immediately following the date the complaint is filed or an investigation is instituted by the Commission on its own motion, calculated on the resulting difference in rates due to the application of the return found to be just and reasonable and the return stated in the formula. The first such effective date for the calculation of refunds shall be January 1, 1989.

Any other complaint which challenges the justness and reasonableness of any other component of the filed formula rate or any other complaint filed at any other time which challenges the justness and reasonableness of the specified rate of return on common equity and which is set for investigation by the Commission shall be pursued under Section 206 of the Federal Power Act.

2. **Operating Ratio**

The Operating Ratio shall be computed each month commencing with the month in which Unit No. 1 at the Plant is placed in commercial operation. It shall be based on the balances, as recorded on the Company's books in accordance with the FERC Uniform

System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall be derived by dividing (a) the amount of Electric Plant In Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations); less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111 but excluding amounts associated with Asset Retirement Obligations); plus Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below); Materials and Supplies (Accounts 151-156 and 163 as adjusted pursuant to the provisions of Note 4.C. below); Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below); Prepayments (Account 165); Deferred Ash pond cost (Account 182.3); other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 less Accounts 232-234, 236, 237, 238, 241 and 242); and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253 including the unamortized gain on the sale of Rockport Unit No. 2); less Asset Retirement Obligation (Account 230); less Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to the plant in service by (b) the sum of (i) the amount determined pursuant to (a) plus (ii) the amount of Construction Work In Progress (Account 707) plus Materials and Supplies (Accounts 151-156 and 163), less Accumulated Deferred Federal Income Taxes related to the construction work in progress plus (iii) Plant Held for Future Use (Account 105), Other Deferred Debits (Account 186) and the amount of fuel inventory over the allowed level (Account 151.10) not otherwise included in (a) above.

3. Net In-Service Investment Ratio

The Unit No. 1 Net In-Service Investment Ratio shall be equal to 1.0 during the period commencing with the month in which Unit No. 1 at the Plant is placed in commercial operation and shall remain at 1.0 up to, but not including, the month in which Unit No. 2 at the Plant is placed in commercial operation. Thereafter, the Net In-Service Investment Ratio shall be computed each month, based on the balances, as recorded on the Company's books in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall be derived as follows:

A. Unit No. 1 Net In-Service Investment Ratio shall be derived by dividing (a) the Net In-Service Investment associated with Unit No. 1 and Common Facilities by (b) the sum of the Net In-Service Investment associated with Unit No. 1 and Common Facilities plus the Net In-Service Investment associated with Unit No. 2.

B. Unit No. 2 Net In-Service Investment Ratio shall be derived by dividing (a) the Net In-Service Investment associated with Unit No. 2 by (b) the sum of the Net In-Service Investment associated with the Unit No. 1 and Common Facilities plus the Net In-Service Investment associated with Unit No. 2.

4. <u>Net In-Service Investment</u>

The Net In-Service Investment shall be computed each month commencing with the month in which Unit No. 2 at the Plant is placed in commercial operation. It shall be based on the balances, as recorded on the Company's books in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall consist of the following:

A. Unit No. 1 Net In-Service Investment shall consist of the sum of Electric Plant in Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations), Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below), Materials and Supplies (Accounts 151-156 and 163 pursuant to the provisions of Note 4.C. below), and Prepayments (Account 165), Deferred Ash pond cost (Account 182.3), Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below), other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 <u>less</u> Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253), less Asset Retirement Obligation (Account 230),less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111), Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to such Unit No. 1 and Common Facilities in-service investment.

B. Unit No. 2 Net In-Service Investment shall consist of the sum of Electric Plant in Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations), Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below), Materials and Supplies (Accounts 151-156 and 163 pursuant to the provisions of Note 4.C. below), Prepayments (Account 165), Deferred Ash pond cost (Account 182.3), Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below), other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 <u>less</u> Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253 including the unamortized gain on the sale of Rockport Unit No.2), less Asset Retirement Obligation (Account 230),less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111), Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to the Unit No. 2 in-service investment.

C. AEGCO shall be permitted to earn a return on its fuel inventory, recorded in Account 151.10, not in excess of a 68-day coal supply as defined herein. To the extent AEGCO's actual fuel inventory exceeds the allowable 68-day level, the return on such excess shall be recorded in a memo account. When AEGCO's actual fuel inventory is less than the allowable 68-day level, AEGCO shall be permitted to recover the return previously unrecovered, but in no event shall the power bill reflect a return on fuel inventory in excess of 68-day supply.

A 68-day coal inventory level shall be determined for each unit annually, and shall be based upon the actual experienced daily burn during the preceding calendar year. The actual experienced daily burn shall be defined to exclude the effect of forced and scheduled outages as well as curtailments as follows:

For each unit:

$$\text{Actual experienced daily burn} = 24 \text{ hours} \left(\frac{\text{Tons burned per year}}{\text{Operating hours}} \right)$$

Where:

Operating hours = Hours in year minus forced and scheduled outage hours minus curtailment equivalent outage hours

and

Curtailment equivalent outage hours = The product for each curtailment of:

$$\frac{\text{kW of curtailed capacity}}{\text{kW of rated capacity}} \quad \text{x} \quad \text{Curtailment hours}$$

The value of the allowable 68-day coal supply used to determine each month's power bill shall be equal to the number of tons determined above multiplied by the cost per ton of coal in inventory at the end of the previous month.

For 1990, a 68-day coal supply for AEGCO's share of Rockport Unit No. 2 shall be based on 12 months ending December 1990 data. For 1990 billing purposes, however, a 68-day coal supply for AEGCO's share of Rockport Unit No.2 shall initially be assumed to be equal to the 68-day coal supply for AEGCO's share of Rockport Unit No. 1, adjusted to reflect the Btu content and the unit cost of the coal for Rockport Unit No. 2.

AEGCO shall maintain a cumulative record of the unrecovered return as well as the subsequent recovery of that return as follows:

i) To the extent that AEGCO's actual fuel inventory exceeds the allowable 68-day coal supply, AEGCO shall record each month an amount equal to the sum of the unrecovered return on fuel inventory and the return on previously unrecovered amounts. The unrecovered return on fuel inventory shall be calculated each month by deriving the difference between the power bill that would result if full recovery were provided and the power bill that results with the 68-day limitation imposed. The return on previously unrecovered amounts shall be calculated by multiplying the cumulative return unrecovered at the end of the previous month by the capital costs used to derive the power bill, adjusted for federal income taxes.

ii) To the extent that AEGCO's fuel inventory is less than the allowable 68-day coal supply, AEGCO shall record each month an amount equal to the return on previously unrecovered amounts less the recovered return in excess of actual inventory levels. The return on previously unrecovered amounts shall be calculated as described in (i) above. The recovered return in excess of actual inventory levels shall be calculated by deriving the difference between the power bill that would result if actual inventory balances were used and the power bill that results with an imputed inventory level. In no event will the cumulative value of the unrecovered return be allowed to fall below zero.

D. AEGCO shall be permitted to include as part of its Net In-Service Investment Numerator amounts subsequently recorded in Accounts 105 and 186 subject to the conditions set forth in the Offer of Settlement in FERC Docket No. ER84-579-000, et al.

E. Other Special Funds (Account 128), Other Current and Accrued Assets (Accounts 131, 135, 143, 146, 171 and 174), Other Deferred Debits (Account 181), Other Current and Accrued Liabilities (Accounts 232-234, 236, 237, 238, 241 and 242), and Other Deferred Credits (Account 253) shall be directly assigned to unit No. 1 (including Common Facilities) or Unit No. 2 whenever possible. Whenever such direct assignment is not practical, such balances shall be allocated between the units in proportion to the net dependable capability of each of the units.

F. To recognize that the lease rental expense will be collected monthly but that the lease payment will be paid semiannually, the lease rental payable balance will be reflected as a rate base reduction in calculating the operating ratio and the Unit 2 net-in-service investment ratio as a means to credit the Unit 2 customers for the time value of money.

5. Investment Balances

For the purpose of calculating the Operating Ratio and Net In-Service Investment Ratio, amounts shall reflect the balances, as recorded on the Company's book in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month, except that when plant greater than or equal to 1% of the prior month ending plant value is transferred into service during the current month, such prior month balances shall be adjusted to reflect such transfers to service. Such adjustment shall be pro-rated for the number of days during the month that such plant addition was in-service.

6. Allocation of Expenses

Operating expenses shall be directly assigned to Unit No. 1 (including Common Facilities) or Unit No. 2 whenever possible. Whenever such direct assignment is not practical, such expenses shall be allocated between the units in accordance with the basis that gave rise to such expense.

AEGCO's operating and maintenance expenses shall include, and AEGCO shall be allowed recovery of, administrative and general expenses, related payroll taxes and other cost, allocated to AEGCO by I&M as operator of the Rockport Plant or incurred directly by AEGCO.

I&M shall allocate to AEGCO, a portion of I&M's administrative and general expenses charged to Accounts 920, 921, 922, 923, 924, 925, 926, 931 and 935; related payroll taxes charge to Account 408; and a portion of the expenses of the Rockport Information Center charged to Accounts 506, 511 and 514 that generally relate to Rockport Plant operations. Such charges shall be allocated to AEGCO on the basis of the ratio of AEGCO's share of the Rockport Plant operation and maintenance wages and salaries, divided by the sum of total Rockport Plant operations and maintenance wages and salaries, plus all other I&M operation and maintenance wages and salaries, less I&M's administrative and general wages and salaries. For the period beginning December 10, 1984 and ending December 31, 1985 this ratio will be developed based on actual 1985 amounts. In subsequent calendar years, this ratio will be adjusted annually based on the prior calendar year's amounts.

AEGCO's operation and maintenance expenses shall also include, and AEGCO shall be allowed recovery of, other administrative and general expenses directly incurred by AEGCO and included in the appropriate administrative and general expense accounts.

BILLINGS AND PAYMENTS

All bills for amounts owing hereunder shall be due and payable on the fifteenth day of the month next following the month or other period to which such bills are applicable, or on the tenth day following receipt of the bill, whichever date is later. Interest on unpaid amounts shall accrue daily at the prime interest rate per annum in effect on the due date at the

Citibank, plus 2% per annum, from the due date until the date upon which payment is made. Unless otherwise agreed upon, the calendar month shall be the standard period for the purpose of settlements under this Agreement. If bills cannot be accurately determined at any time, they shall be rendered on an estimated basis and subsequently adjusted to conform to the terms of the unit power agreements.

AEP GENERATING COMPANY
SAMPLE POWER BILL
SUMMARY OF MONTHLY POWER BILL

Line No.		Amount
1	Return on Common Equity	
2	Return on Other Capital	

3	Total Return	
4	+ Fuel	
5	+ Purchased Power	
6	- Other Operating Revenues	
7	+ Other Operation and Maintenance Exp	
8	- Depreciation, Amortization and Accretion Expenses	
9	+ Taxes Other Than Federal Income Tax	
10	+ Federal and State Income Tax	

11	= Total Unit 1 Monthly Power Bill	
		===============
12	Determination of Federal Income Tax :	
13	Total Return (Line 3)	
14	+ Unit 1 Schedule M Adjustments	
15	+ Unit 1 Deferred Federal Income Taxes	
16	- Unit 1 Interest Expense Deduction *	

17	= Subtotal	
18	x Gross-Up (FIT Rate / 1-FIT Rate)	
19	= Unit 1 Current Federal Income Tax	
20	+ Unit 1 Def Fed & State Income Taxes	

21	= Total Unit 1 Fed&State Income Taxes	
		===============
22	Proof of Federal Income Tax :	
23	Total Unit 1 Monthly Power Bill	
24	- Operation and Maintenance Expenses	
25	- Depreciation, Amortization and Accretion Expenses	
26	- Taxes Other Than Federal Income Tax	
27	- Unit 1 Interest Expense Deduction *	
28	+ Other Operating Revenues	

29	= Pre-Tax Book Income	
30	+ Unit 1 Schedule M Adjustments	

31	= Unit 1 Taxable Income	
32	x Current Federal Income Tax Rate	
33	= Unit 1 Current Federal Income Tax	
34	+ Unit 1 Def Fed & State Income Taxes	

35	= Total Unit 1 Fed&State Income Taxes	
		===============

* From Page 4 of 18 : Line 21 + (Line 28 x Line 31 x Line 32)

AEP GENERATING COMPANY
SAMPLE POWER BILL
OPERATING RATIO

Line No.		Amount
1	Operating Ratio:	
2	Net In-Service Investment:	
3	Electric Plant In-Service	
4	- Accumulated Depreciation	
5	+ Materials & Supplies	
6	+ Prepayments	
7	+ Plant Held For Future Use (A/C 105) *	
8	+ Other Deferred Debits (A/C 186) *	
9	+ Other Working Capital ***	
10	+ Unamortized Debt Expense (A/C 181)	
11	+ Deferred ASH pond cost (A/C 182.3)	
12	- Asset Retirement Obligation (A/C 230)	
13	- Other Deferred Credits (A/C 253)	
14	- Accumulated Deferred FIT	
15	- Accumulated Deferred ITC	

16	Total Net In-Service Investment	

17	Non-In-Service Investment - CWIP :	
18	Construction Work In Progress	
19	+ Materials & Supplies	
20	- Accumulated Deferred FIT	

21	Total Non-In-Service Investment - CWIP	

22	Non-In-Service Investment - Other :	
23	Plant Held for Future Use (A/C 105) **	
24	+ Other Deferred Debits (A/C 186) **	
25	+ Fuel Inventory Over Allowed Level ****	

26	Total Non-In-Service Investment - Other	

27	Total Investment (Lines 16+21+26)	
		============
28	Operating Ratio (Line 16/Line 27)	
29	Non-In-Service Investment-CWIP Ratio (Line 21/Line 27)	
30	Non-In-Service Investment-Other Ratio (Line 26/Line 27)	

31	Total Investment	
		============

* As Permitted By FERC
** Excluding Amounts on Lines 7 and 8
*** Accounts 128, 131, 135, 143, 146, 171 and 174, Less Accounts 232-234, 236, 237, 238, 241 and 242
**** Includes Rockport 1 and 2

AEP GENERATING COMPANY
SAMPLE POWER BILL
NET IN-SERVICE INVESTMENT RATIO

Line No.		Amount
1	Net In-Service Investment Ratio:	
2	Unit 1 Net In-Service Investment:	
3	Electric Plant In-Service	
4	- Accumulated Depreciation	
5	+ Materials & Supplies	
6	+ Prepayments	
7	+ Plant Held For Future Use (A/C 105) *	
8	+ Other Deferred Debits (A/C 186) *	
9	+ Other Working Capital **	
10	+ Unamortized Debt Expense (A/C 181)	
11	+ Deferred ASH pond cost (A/C 182.3)	
12	- Asset Retirement Obligation (A/C 230)	
13	- Other Deferred Credits (A/C 253)	
14	- Accumulated Deferred FIT	
15	- Accumulated Deferred ITC	

16	Total Unit 1 Net In-Service Investment	

17	Unit 2 Net In-Service Investment:	
18	Electric Plant In-Service	
19	- Accumulated Depreciation	
20	+ Materials & Supplies	
21	+ Prepayments	
22	+ Plant Held For Future Use (A/C 105) *	
23	+ Other Deferred Debits (A/C 186) *	
24	+ Other Working Capital **	
25	+ Unamortized Debt Expense (A/C 181)	
26	+ Deferred ASH pond cost (A/C 182.3)	
27	- Asset Retirement Obligation (A/C 230)	
28	- Other Deferred Credits (A/C 253)	
29	- Accumulated Deferred FIT	
30	- Accumulated Deferred ITC	

31	Total Unit 2 Net In-Service Investment	

32	Total Net In-Service Investment	
		============
33	Net In-Service Investment Ratio:	
34	Unit 1 (Line 16 / Line 32)	
35	Unit 2 (Line 31 / Line 32)	

		============

* As Permitted By FERC
** Accounts 128, 131, 135, 143, 146, 171 and 174,
Less Accounts 232-234, 236, 237, 238, 241 and 242

AEP GENERATING COMPANY
SAMPLE POWER BILL
CALCULATION OF RETURNS ON
COMMON EQUITY & OTHER CAPITAL

Line No.		Amount
1	Net Capitalization:	
2	Long-Term Debt	
3	+ Short-Term Debt	
4	+ Preferred Stock	
5	+ Common Equity	
6	- Temporary Cash Investments	

7	Net Capitalization	
		============
8	40% of Net Capitalization	
9	Return on Common Equity:	
10	Lesser of Line 5 or Line 8	
11	x Equity Return (Monthly Rate)	
12	= Equity Return	
13	x Operating Ratio	
14	x Net In-Service Investment Ratio	
15	= Subtotal	
16	Excess of Line 5 Over Line 8	
17	x Weighted Cost of Debt (Monthly Rate)	
18	= Return on Equity over 40% of Capitalization	
19	x Operating Ratio	
20	x Net In-Service Investment Ratio	
21	= Subtotal	

22	Unit 1 Return on Equity (Line 15 + Line 21)	
		============
23	Return on Other Capital:	
24	Long-Term Debt Interest Expense (A/C 427-429)	
25	+ Short-Term Debt Interest Expense (A/C 430)	
26	+ Other Interest Expense (A/C 431)	
27	- Temporary Cash Investment Income *	

28	= Net Interest Expense	
29	+ Preferred Stock Dividends (a/c 437)	

30	= Net Cost of Other Capital	
31	x Operating Ratio	
32	x Net In-Service Investment Ratio	
33	= Unit 1 Return on Other Capital	
		============

* Line 6 x Line 19 from Pg 5 of 18

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETERMINATION OF WEIGHTED COST OF DEBT

Line No.		Amount
1	Debt Balances (Prior Month Ending) :	
2	Long-Term Debt	
3	+ Short-Term Debt	
4	+ Other Debt	

5	Total Debt Balances (Prior Month Ending)	
		=============
6	Weighting of Debt Balances :	
7	Long-Term Debt	
8	+ Short-Term Debt	
9	+ Other Debt	

10	Total Debt Balances	
		=============
11	Debt Cost Rates :	
12	Long-Term Debt	
13	Short-Term Debt	
14	Other Debt	
15	Weighted Cost of Debt :	
16	Long-Term Debt	
17	+ Short-Term Debt	
18	+ Other Debt	

19	Total Weighted Cost of Debt	
		=============

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETERMINATION OF UNIT 1 MATERIALS AND SUPPLIES

Line No.		Amount
1	Unit 1 Materials and Supplies:	
2	Fuel Stock - Coal (per Line 23)	
3	Fuel Stock Expenses - Undistributed (152)	
4	Fuel Stock - Oil (151)	
5	Plant Materials & Operating Supplies	
6	Merchandise	
7	Undistributed Stores Expense	

8	Total Materials & Supplies	
		===========
9	Support of Coal Inventory Value:	
10	Actual Coal Inventory (A/C 151.10)	
11	+ Equivalent Inventory re: Deferred Return	

12	= Imputed Coal Inventory	

13	Coal Inventory W/68 Day Supply Cap	
14	Tons Consumed	
15	/ Hours Available *	
16	= Tons Consumed per Hour	
17	x 24 Hours per Day	
18	= Tons Consumed Per Day	
19	x 68 days	
20	= 68 day Supply (Tons)	
21	x Coal Cost per Ton (per A/C 151.10 at End of Prior Month)	

22	= 68 day Coal Inventory	

23	Lesser of Imputed or Capped Coal Inventory	

24	Imputed Inventory Minus Line 23	
		===========
25	Accumulated Deferred Inventory Return - Unit 1 (Memo Item):	
26	Beginning Balance	
27	+ Current Month Return on Beginning Balance	
28	+ Current Month Deferral	
29	- Current Month Recovery	

30	= Ending Balance **	
		===========

* Excludes Forced Outages,Scheduled Outages,and Curtailments
** May Not Be Less Than Zero

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF OTHER OPERATING REVENUES

Line No.	Account No.	Description	Amount
1	450	Forfeited Discounts	
2	451	Miscellaneous Service Revenues	
3	453	Sales of Water and Water Power	
4	454	Rent From Electric Property - Associated Companies	
5	454.20	Rent From Electric Property - Non-Associated Companies	
6	455	Interdepartmental Rents	
7	456	Other Electric Revenues	
8	411.8	Proceeds/Gains From Sale of Emission Allowances	
9		Total Other Operating Revenues	===========

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF OPERATION & MAINTENANCE EXPENSES

Line No.	Account No.	Description	Amount
1	500, 502-508	Steam Power Generation - Operation	
2	501	Fuel - Operation	
3	510-515	Steam Power Generating - Maintenance	

4		Total Steam Power Generation Expenses	

5	555-557	Other Power Supply Expenses	

6	560-567.1	Transmission Expenses - Operation	
7	568-574	Transmission Expenses - Maintenance	

8		Total Transmission Expenses	

9	580-589	Distribution Expenses - Operation	
10	590-598	Distribution Expenses - Maintenance	

11		Total Distribution Expenses	

12	901-905	Customer Accounts Expenses - Operation	

13	906-910	Customer Service and Informational Expenses - Operation	

14	911-917	Sales Expenses - Operation	

15	920-933	Administrative and General Expenses - Operation	
16	935	Administrative and General Expenses - Maintenance	

17		Total Administrative & General Exp.	

18		Total Operation & Maintenance Expenses	
			===========

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF DEPRECIATION,
AMORTIZATION AND ACCRETION EXPENSES

Line No.	Account No.	Description	Amount
1	403	Depreciation Expense	
1a	403.1	ARO Depreciation Expense	
2	404	Amortization of Limited-Term Electric Plant	
3	405	Amortization of Other Electric Plant	
4	406	Amortization of Electric Plant Acquistion Adjustments	
5	407	Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs	
6		Total Depreciation Exp. & Amortization	
7	411.10	ARO Accretion Expense	
8		Total Depreciation, Amortization & Accretion Expenses	==============

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF TAXES OTHER THAN FEDERAL INCOME TAXES

Line No.	Account No.	Description	Amount
BS1			
1	408.1	Taxes Other Than Federal Income Taxes, Utility Operating Income	
2	409.1	State Income Taxes	

3		Total Taxes Other than FIT	
			===========

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF UNIT 1 SCHEDULE `M' ADJUSTMENTS
AND DEFERRED FEDERAL AND STATE INCOME TAX

Line No.	Account No.	Description	Amount
1		Unit 1 Schedule `M' Adjustments	
2	N/A	Excess ACRS Over Normalization Base Depreciation	
3	N/A	Excess Normalization Base Over Book Depreciation	
4	N/A	Other Unit 1 Schedule `M' Adjustments	------------------
5		Total Unit 1 Schedule `M' Adjustments *	==========
6		Unit 1 Deferred Federal Income Tax	
7	410.1	Excess ACRS Over Norm. Base Depr. (Line 2 x FIT Rate * -1)	
8	410.1, 411.1	Other Unit 1 Schedule `M' Adjustments -	
9	411.1	Feedback of Accumulated DFIT re: ABFUDC - Unit 1 Negative Amount Denotes Reduction.	
10	411.1	Feedback of Accumulated DFIT re: Overheads Capitalized - Unit 1	------------------
11	411.1	Feedback of Accumulated DFIT re: Other Schedule `M' Adj.-Utility	==========
12		Total Unit 1 Deferred Federal and State Income Tax *	

* Positive Amount Denotes Increase In Taxable Income,
Negative Amount Denotes Reduction.

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF NET IN-SERVICE INVESTMENT UNIT 1

Line No.	Account No.	Description	Amount
1		ELECTRIC PLANT IN SERVICE	
2	101	Electric Plant In Service	
3	102	Electric Plant Purchased	
4	103	Experimental Elec. Plant Unclassified	
5	103.1	Electric Plant In Process of Reclassification	
6	104	Electric Plant Leased to Others	
7	106	Completed Construction Not Classified	
8	114	Electric Plant Acquisition Adjustments	
9	116	Other Electric Plant Adjustments	
10	118	Other Utility Plant	

11		Total Electric Plant In Service	

12	105	Plant Held For Future Use	
13		ACCUMULATED DEPRECIATION	
14	108	Accumulated Provision for Depreciation of Electric Utility Plant	
15	110	Accumulated Provision for Depreciation and Amort. of Elec. Utility Plant	
16	111	Accumulated Provision for Amortization of Electric Utility Plant	
17	115	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments	
18	119	Accumulated Provision for Depreciation and Amortization of Other Utility Plant	

19		Total Accumulated Depreciation	

20		MATERIAL AND SUPPLIES	
21	151	Fuel Stock	
22	152	Fuel Stock Expenses - Undistributed	
23	153	Residuals	
24	154	Plant Materials and Operating Supplies	
25	155	Merchandise	
26	156	Other Materials and Supplies	
27	163	Stores Expense Undistributed	
28		Total Materials and Supplies (In-Service Portion)	--------------------
			--------------------
29	165	Prepayments	

30	186	Other Deferred Debits	

AEP GENERATING COMPANY
SAMPLE POWER BILL
OTHER WORKING CAPITAL, UNAMORTIZED DEBT EXPENSE, AND OTHER DEFERRED CREDITS

Line No.	Account No.	Description *	Amount
1	128	Other Special Funds	
2	131	Cash	
3	135	Other Intra Company Adjustments	
4	143	Accounts Receivable-Miscellaneous	
5	146	Accounts Receivable-Associated Company	
6	171	Interest and Dividends Receivable	
7	174	Miscellaneous Current and Accrued Assets	
8	232	Accounts Payable-General	
9	234	Accounts Payable-Associated Company	
10	236	Taxes Accrued	
11	237	Interest Accrued	
12	238	Dividends Declared	
13	241	Tax Collections Payable	
14	242	Misc Current and Accrued Liabilities	

15		Total Other Working Capital	
			==========
16	181	Unamortized Debt Expense	

17	253	Other Deferred Credits	
			------------------

* debit <credit>

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF NET IN-SERVICE INVESTMENT UNIT 1

Line No.	Account No.	Description	Amount
31		ACCUMULATED DEFERRED INCOME TAXES	
32	190	-Accumulated Deferred Income Taxes	
33	281	+Accumulated Deferred Income Taxes - Accelerated Amortization Property	
34	282	+Accumulated Deferred Income Taxes - Other Property	
35	283	+Accumulated Deferred Income Taxes - Other	
36		Total Accumulated Deferred Income Taxes (In-Service Portion)	---------------------
			---------------------
37	255	+Accumulated Deferred Investment Tax Credits	
38	186.50	-Accumulated Deferred Investment Tax Credit	
39		Total Accumulated Deferred Investment Tax Credits	---------------------
40		Total Net In-Service Investment - Unit 1	---------------------
			============

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF NON-IN-SERVICE INVESTMENT - CWIP AND OTHER

Line No.	Account No.	Description	Amount
		Non-In-Service Investment - CWIP	
1	107	Construction Work In Process	
2		MATERIAL AND SUPPLIES	
3	151	Fuel Stock	
4	152	Fuel Stock Expenses - Undistributed	
5	153	Residuals	
6	154	Plant Materials and Operating Supplies	
7	155	Merchandise	
8	156	Other Material and Supplies	
9	163	Stores Expense Undistributed	
10		Total Material and Supplies (CWIP Portion)	-----------------
			-----------------
11		ACCUMULATED DEFERRED INCOME TAXES	
12	190	-Accumulated Deferred Income Taxes	
13	281	+Accumulated Deferred Income Taxes - Accelerated Amortization Property	
14	282	+Accumulated Deferred Income Taxes - Other Property	
15	283	+Accumulated Deferred Income Taxes - Other	
16		Total Accumulated Deferred Income Taxes (CWIP Portion)	-----------------
			-----------------
17		TOTAL NON-IN-SERVICE INVESTMENT - CWIP	
			==========
		Non-In-Service Investment - Other	
18	105	Plant Held for Future Use	
19	186	Other Deferred Debits	
20	151.10	Fuel Inventory Over Allowed Level *	
21		Total Non-In-Service Investment - Other	-----------------
			==========

* INCLUDES ROCKPORT 1 AND 2

UNIT 1	
UNIT 2	

TOTAL	
	==========

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF NET CAPITALIZATION

Line No.	Account No.	Description	Amount
1		COMMON CAPITAL STOCK	
2	201	Common Stock Issued	
3	202	Common Stock Subscribed	
4	203	Common Stock Liability for Conversion	
5	209	Reduction In Par or Stated Value of Capital Stock	
6	210	Gain on Resale or Cancellation of Reacquired Capital Stock	
7	212	Installments Received on Capital Stock	
8	214	Capital Stock Expense	
9	217	Reacquired Capital Stock	

10		Total Common Capital Stock	

11		OTHER PAID-IN CAPITAL	
12	207	Premium on Capital Stock	
13	208	Donations Received from Stockholders	
14	211	Miscellaneous Paid-In Capital	
15	213	Discount on Capital Stock	

16		Total Other Paid-In Capital	

17		RETAINED EARNINGS	
18	215	Appropriated Retained Earnings	
19	215.1	Appropriated Retained Earnings- Amortization Reserve, Federal	
20	216	Unappropriated Retained Earnings	

21		Total Retained Earnings	

22		Total Common Equity	

23		PREFERED CAPITAL STOCK	
24	204	Preferred Stock Issued	
25	205	Preferred Stock Subscribed	
26	206	Preferred Stock Liability for Conversion	

27		Total Preferred Capital Stock	

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF NET CAPITALIZATION (Cont'd)

Line No.	Account No.	Description	Amount
28		LONG-TERM DEBT	
29	221	Bonds	
30	222	Reacquired Bonds	
31	223	Advances from Associated Companies	
32	224	Other Long-Term Debt	
33	225	Unamortized Premium on Long-Term Debt-Credit	
34	226	Unamortized Discount on Long-Term Debt-Debit	

35		Total Long-Term Debt	

		SHORT-TERM DEBT	
36a	231.02	Notes Payable (Short-Term Debt)	
36b	231.03	Unamortized Discount	
37	233.00	Notes Payable, Assoc Co (Money Pool)	

38		Total Short-Term Debt	

39		TEMPORARY CASH INVESTMENTS	
40	132	Interest Special Deposits	
41	133	Dividend Special Deposits	
42	134	Other Special Deposits	
43	136, 145	Temporary Cash Investments	

44		Total Temporary Cash Investments	

45		NET CAPITALIZATION	
			=========

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETERMINATION OF RATE OF RETURN (Net & Pre-Tax)

Line No.		Amount
1	Capitalization Balances (Prior Month Ending) :	
2	Long-Term Debt	
3	+ Short-Term Debt	
4	+ Preferred Stock	
5	+ Common Equity	
6	- Capitalization Offsets	

7	Total Capitalization Balances	
		===========
8	Weighting of Capitalization Balances :	
9	Long-Term Debt	
10	+ Short-Term Debt	
11	+ Preferred Stock	
12	+ Common Equity	
13	- Capitalization Offsets	

14	Total Capitalization	
		===========
15	Capitalization Cost Rates :	
16	Long-Term Debt	
17	Short-Term Debt	
18	Preferred Stock	
19	Common Equity	
20	Capitalization Offsets	
21	Rate of Return (Net of Tax) :	
22	Long-Term Debt	
23	+ Short-Term Debt	
24	+ Preferred Stock	
25	+ Common Equity	
26	- Capitalization Offsets	

27	Total Rate of Return (Net of Tax)	
		===========
28	Weighted Net Cost of Debt	
29	+ Pre-Tax Common Equity (Line 25 / .65)	

30	= Rate of Return (Pre-Tax)	
		===========

DATA REQUEST

KPSC_PH_005 Provide the summer and winter reserve margins and system peak for the previous five years, and the forecasted summer and winter reserve margins and system peak for the next five years for:
a. Appalachian Power Company ("Appalachian Power"};
b. Indiana Michigan Power Company ("I&M Power"); and
c. Wheeling Power Company ("Wheeling Power").

RESPONSE

The Company no longer prepares winter reserve margins for APCo, I&M or Wheeling Power due to the October 1, 2004 integration of AEP's Eastern System into the PJM Interconnection; the AEP Operating Companies are now required to comply with the PJM mandated summer reserve margin requirements. Please see KPCO_R_KPSC_PH_5_Attachment1.xlsx for the requested historic and forecasted summer peaks and reserve margins.

Witness: Alex E. Vaughan

DATA REQUEST

KPSC_PH_006 Refer to Kentucky Power Hearing Exhibit 9, which evaluates whether Kentucky Power, Appalachian Power, I&M Power, and Wheeling Power will participate in PJM Interconnection LLC's ("PJM") Reliability Pricing Model ("RPM") capacity market or whether each will continue to self-supply its PJM capacity requirements under the Fixed Resource Requirement ("FRR") alternative for the PJM Planning Year 2020-2021. Provide the same PJM FRR/RPM capacity election analysis for Kentucky Power only, excluding the other AEP subsidiaries.

RESPONSE

Even when viewed in isolation, and without considering its AEP-East operating company affiliates, it is in the best interest of Kentucky Power and its customers for Kentucky Power to remain an FRR entity.

FRR maintains a historical advantage of a lower Installed Reserve Margin (IRM) of 16.6% versus RPM typically clearing in the ~20% range. Specifically, the RPM Base Residual Auction for Plan Year 20/21 had a cleared IRM of 23.3%, giving the FRR choice a 28.8% lower reserve margin.

Additionally, switching from FRR to RPM requires a five year commitment to RPM. PJM has continuously revamped the RPM rules. Remaining FRR increases certainty by dampening the Company's exposure to the changing RPM rules.

The decision to continue to supply KPCO customers under the FRR construct was further strengthened as a result of the newer PJM Capacity Performance rules. As an FRR entity, Kentucky Power can use physical capacity replacement, if any non-performance occurs during PJM Performance Hours, at approximately one-third the cost or less of the RPM financial charge that would be assessed for a non-performance.

For example, the charge for RPM Capacity Performance is ~$3,500/MWh for any non-performance during a Performance Hour. (PJM estimates 30 performance hours a year). Thus, if 1,000 MW of capacity is forced out for only one Performance Hour, the RPM financial charge would be $3.5 million.

As an FRR participant, if Kentucky Power has any non-performance hours, physical replacement of MW's can be used the following year. The PJM formula for this FRR physical equivalent results in Kentucky Power requiring only an additional 16.6 MWs of capacity for the 1,000 MW forced outage example above. Kentucky Power is likely to have this small incremental length. In any event, if Kentucky Power must purchase the replacement capacity for a high price of $200/MW-day, the total costs is $1.21 million, or approximately one-third the cost of the $3.5 million RPM financial.

Witness: Matthew J. Satterwhite

DATA REQUEST

KPSC_PH_007 Provide the cost savings that resulted from the steps taken by Kentucky Power to reduce the growth rate of compensation expense as set forth in the Direct Testimony of Andrew R. Carlin, page 21 , lines 10-20. Include the savings that resulted from each step and the total amount of savings.

RESPONSE

The following excerpt from AEP's 2009 annual report provides background for the actions listed in Mr. Carlin's testimony:

> **"EXECUTIVE OVERVIEW**
>
> *Economic Conditions*
>
> In 2009, our operations were impacted by difficult economic conditions. While our 2009 residential and commercial KWH sales were down moderately in comparison to 2008, our industrial KWH sales declined substantially in 2009 by 16%. Approximately half of the decrease was due to cutbacks or closures by 10 of our large metals producing customers. We also experienced varying decreases in KWH sales to customers in the transportation, plastics, rubber and paper manufacturing industries. We forecast a recovery in industrial sales volumes of approximately 5% in 2010 as compared to 2009. Margins from off-system sales decreased due to reductions in sales volumes and weak market prices for power, reflecting reduced overall demand for electricity. Off-system sales volumes decreased by 50% in 2009. We forecast a recovery in off-system sales volumes of approximately 60% in 2010 as compared to 2009."

AEP and Kentucky Power Company (collectively the "Company") have undertaken a series of efficiency initiatives. While these initiatives were designed to provide sustainable O&M savings in specific areas, overall total O&M expenses will likely increase over time.

Steps 1, 3 and 4: These steps (Step 1: a freeze in external hiring, Step 3: reduction in the use of external contractors and temporary employees, and step 4: employee workforce reductions through staff reductions and severance programs) were part of an overall strategy to reduce expense and expense escalation. A multi-pronged strategy was utilized to avoid the potential that cost savings in one area, such as reduced labor expense due to staff reductions, to be offset by cost increases in another area, such as by increased use of external contractors. As such, these cost savings were tracked as a combined total. For Kentucky Power Company the estimated 2010 O&M savings was $7.7 million and the estimated 2011 O&M savings (annualize and sustainable) was $10.0 million, using an estimated jurisdictional share of 5% of the savings as Kentucky Power's share. Additionally, these estimated savings did not include the estimated costs to achieve such savings, as discussed and disclosed in the Kentucky Power Company 2010 Annual Report as follows:

"14. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment on May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. Management does not expect additional costs to be incurred related to this initiative.

Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance at December 31, 2010
(in thousands)				
$ 3,481	$ 8,175	$ 12,001	$ 1,363	$ 1,018

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the Statements of Income and Other Current Liabilities on the Balance Sheets."

Please see KPCO_R_KPSC_PH_007_Attachment1.xlsx for the estimated savings.

Step 2: The freeze on line of progression promotional increases from November 2008 through 2010, other than for physical/craft positions, was also part of the overall strategy to reduce expense and expense escalation. However, because line of progression promotions are generally not specifically forecasted or budgeted, they are not included in the cost savings described in step 1 above. Estimates of the cost savings associated with freezing line of progression promotional increases range from approximately $264,000 to $419,000 for Kentucky Power Company during this period, exclusive of the savings from the approximately 2 month period in 2008 during which the freeze was in place. Because these costs are generally not forecasted or budgeted, these estimates were derived by comparing the cost of such increases during the freeze period to the cost of such increases during later periods (2012-2013 or 2011-2016). Please see KPCO_R_KPSC_PH_007_Attachment2.xlsx.

Steps 1-4: While the cost savings described in steps 1-4 are necessarily estimated, these estimates are supported by Kentucky Power Company's 2010 O&M expense vs. Budget, which was $12.2 million (10.7%) lower than budget overall. Please see KPCO_R_KPSC_PH_007_Attachment3.xlsx.

Step 5: The Company continuously strives to operate efficiently and cost-effectively. While efficiency measures discussed below, such as LEAN and other continuous improvement initiatives, are specific initiatives, they are a part of a culture of cost efficiency and cost-effectiveness that the Company continuously strives to achieve at all levels of its organization.

During 2012, AEP conducted a review of company-wide processes, which was referred to as the repositioning study. This review included an evaluation of employee and retiree benefit programs, and an evaluation of functional operational effectiveness and staffing levels of the following company organizations: finance and accounting; information technology; generation; and supply chain and procurement. Engage to Gain, was a one-year employee program in 2013. This program provided cash awards to employees in 2014 for ideas resulting in sustainable O&M savings or incremental revenues generated in 2013, over and above a target level. As a result of the repositioning study and Engage to Gain, a number of sustainable system-wide process improvements were implemented in 2013. This included the elimination of levels of management in some company organizations. For Kentucky Power Company the estimated O&M savings was $5.45M, which consisted of $2.59 million in Kentucky Power Company direct expense and $2.86M of corporate savings allocated to Kentucky Power Company (3% of the total).

Beginning in 2012, The Company used "lean" processes across the organization as part of its efforts to continuously improve and enhance efficiency. Employees at all levels were asked to review their work processes on an ongoing basis to look for ways to improve safety and increase productivity by reducing waste. The "lean" process seeks ways for the Company to operate as efficiently as possible, so as to be able to redirect dollars to needed investments to serve customers and to cover other expenses that are likely to increase over time. A total of 19 ideas and 23 quick wins were being pursued as of Oct. 2015, although most of these initiatives resulted in only soft dollar savings, such as process improvements that enable additional work with existing resources. One project realized a hard dollar savings of $265,000 due to the elimination of one contract underground crew effective January 1, 2016.

The estimated cost to achieve these anticipated savings from all the step 5 initiatives are not included within this estimate. Some of the estimated costs to achieve were disclosed in the Kentucky Power Company 2013 Annual Report as follows:

> **"17. SUSTAINABLE COST REDUCTIONS**
>
> In April 2012, management initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. Management selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge of $2 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance at December 31, 2013
(in thousands)					
$ 497	$ 180	$ -	$ (276)	$ (401)	$ -

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the statements of income. Management does not expect additional costs to be incurred related to this initiative."

Step 6: As Tables ARC-2 and ARC-3 on pages 18 and 20 of Mr. Carlin's direct testimony show, the Company's wage increases lagged market wage increases by a significant amount during the 2009 to 2016 period. This was primarily due to the wage freeze the Company implemented in 2009. The Company took measured steps over time to adjust lagging employee compensation to market over time by providing slightly larger than market wage increases in later years, primarily 2015 and 2016. However, these wage increases have been insufficient to make up the shortfall as compared to market during this period.

The cost saved by this measured approach taken over time is estimated based on the cost that would have been incurred if less measured approach had been taken earlier in the period. For the purposes of this estimate, the specific less measured and accelerated approach chosen is an increase in the wage increase budget for all categories of employees to 3.5% beginning in 2011. These increases would have nearly closed the gap to market wage increases by 2016 for all categories of employees but these wage increases still would not have exceeded market wages increases for the 2009 to 2016 period. The estimated total and O&M savings achieved for Kentucky Power Company through 2016 from not having taken this less measured approach is $7.6M. Please see KPCO_R_KPSC_PH_007_Attachment4.xlsx.

The pending test year base case request, with associated adjustments, already reflects the historical costs and savings associated with the above initiatives into the base rate request. Further, the pending base rate case request reflects the just, necessary and reasonable costs to serve the customers of Kentucky Power.

The total cost savings for steps 1-6 is $33,156,500. Please see KPCO_R_KPSC_PH_007_Attachment5.xlsx.

Witness: Tyler H. Ross
Andrew R. Carlin

DATA REQUEST

KPSC_PH_008 Refer to the Direct Testimony of Brad Hall, page 12, lines 2- 10, and to Mr. Hall's testimony at the December 6-8, 2017 hearing in this matter. Provide the rate class under which each projected new business referenced will take service from Kentucky Power.

RESPONSE

Please see KPCO_R_KPSC_PH_8_Attachment1.xls.

Witness: Alex E. Vaughan
Brad N. Hall

DATA REQUEST

KPSC_PH_009 Provide documentation that demonstrates that the interest rates charged by from the bank consortium used by AEP Credit, Inc. ("AEP Credit") for accounts receivable purchased by AEP Credit from Kentucky Power are the same rates AEP Credit is charging Kentucky Power.

RESPONSE

AEP Credit purchases accounts receivable from Kentucky Power at a discount. The discount taken compensates AEP Credit for costs associated with financing and recovering receivables purchased without recourse. The discount consists of a carrying charge (financing costs), collection experience (bad debt), and an agency fee (administrative costs). The carrying charge is presented and included in the Company's capital structure and proposed weighted average cost of capital. The collection experience (bad debt) and agency fees are included in the Company's cost of service. The bad debt expense included on Kentucky Power's books is <u>not</u> in addition to the bad debt component of the discount. Instead, when a customer is billed $100 Kentucky Power records revenue of $100. Upon selling its receivables, the Company makes accounting entries to reflect the three components comprising the factoring discount. As a result, the costs associated with each component of the discount, including bad debt, are reflected only once.

The interest rates or carrying charge AEP Credit bills to Kentucky Power for accounts receivable financing are a direct pass through based on actual financing costs which compensate AEP Credit for the costs associated with financing the purchased receivables. See attachment KPCO_R_KPSC_PH_9_Attachment1.pdf and KPCO_R_KPSC_PH_9_Attachment2.xls, for the resquested documentation.

KPCO_R_KPSC_PH_9_Attachment1, page 1 of 3, includes the daily interest rates for July 18, 2016 provided by conduit banks and calculates the total weighted daily conduit interest rate of 0.6310%, which is highlighted in green near the bottom of the page. The weighted daily conduit interest rate of 0.6310% is carried over to the top of page 2 of 3 and inputted into the calculation of the weighted daily total debt interest rate of 0.6840% highlighted in orange. Finally, the weighted daily total debt interest rate is carried over to the top of page 3 of 3 and is included as the interest cost component of the daily carrying cost calculation charged to Kentucky Power. The daily carrying cost rate is calculated at 0.1366% and is bolded and highlighted in blue near the bottom of page 3.

KPCO_R_KPSC_PH_9_Attachment2 shows the daily total carrying costs of accounts receivable financing for the test year ended February 28, 2017. Row 177, dated July 18, 2016 of the attachment, shows the total daily carrying cost rate and amount charged to Kentucky Power. The total carrying costs of 0.1366% within cell J177 (highlighted in blue) equals the daily carrying cost rate calculated on KPCO_R_KPSC_PH_9_Attachment1, page 3 of 3. The average daily carrying charges are then annualized and presented as the cost of accounts receivable financing included in Kentucky Power's proposed cost of capital schedule.

For rate-making purposes, the carrying cost component is reflected in Kentucky Power's capital structure, while the collection experience and agency fee component are included in Kentucky Power's cost of service.

By way of background, AEP Credit, Inc, is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), and was formed for the sole purpose of purchasing accounts receivables at a discount and financing these purchases at a highly levered debt-equity ratio.

AEP Credit enters into separate purchase agreements with each Operating Company. AEP Credit finances its purchase of these receivables by using funds obtained from a group of conduit banks, equity contributions from AEP, and proceeds of a subordinated revolving loan by AEP. Each Operating Company pays a discount based on actual financing costs and each Operating Company to pays no more nor no less than the actual costs associated with *its* pool of receivables.

Each company selling its receivables to Credit has executed a "Purchase Agreement" and an "Agency Agreement" which outline how the basic transactions take place. Either party upon 30 days written notice to the other may terminate the Purchase Agreement and Agency Agreement.

The affiliate companies that currently utilize Credit are Appalachian Power Company – Virginia (APCO), Indiana Michigan Power Company (I&M), Kentucky Power Company (KP), Kingsport Power Company (KGP), Ohio Power Company (OP), Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO) The affiliate companies are individually known as "Seller" and collectively known as "Sellers."

Each Seller has agreed through the Agency Agreement to service, administer, and collect such receivables on behalf of Credit. As long as a Seller acts as the agent, Credit agrees to pay the Seller an agent collection fee. Payment of the agent collection fee is made simultaneously with collections, by deducting the fee from funds owed to Credit for receivables collected.

The sale of receivables program allows the Operating Companies to reduce their working capital needs by accelerating the receipt of cash flows from the collection of customer accounts receivable, and thereby reducing the dependence of the Operating Companies upon more costly sources of capital. AEP Credit, as a special purpose financing entity, can borrow money more cheaply than the Operating Companies can individually. Through the use of Credit, the Operating Companies also are able to consolidate their accounts receivable into a larger pool and eliminate duplicate administrative costs in administering the program.

Witness: Zachary C. Miller

AEP Credit

Kentucky Power Company

Accounts Receivable Factoring

Monday, July 18, 2016

	Retail	*Wholesale*
Interest Cost	0.00684	0.00684
x Debt Percent	0.916	0.95
Debt Component	0.006265	0.006498
Allowed ROCE	0.1025	0.1149
/ Tax Effect	0.62	0.62
Pretax ROCE	0.165323	0.185323
x Equity Percent	0.084	0.05
Equity Component	0.013887	0.009266
Total Annual Capital Costs	0.020152	0.015764
/ Days in Year	360	360
Daily Capital Cost Factor	0.000056	0.000044
x Average Days Outstanding	24.4	0
Carrying Cost Component	**0.001366**	**0**
Carrying Cost Component	0.001366	0
Collection Experience Component	0.002683	0
Agent Fee Component	0.02	0.02
Total Discount Factor	0.024049	0.02

7/14/2016		7/14/2016
Daily Conduit Debt Rate	0.6310%	
Daily Corporate Debt Rate	0.8510%	
Daily Equity Outstanding Balance	**$129,671,049.55**	13.14%
Daily Conduit Outstanding Amount	$651,000,000.00	65.96%
Daily Corporate Outstanding Amount	$206,295,518.05	20.90%
Total Daily Outstanding Debt	**$857,295,518.05**	
Total Current Capitalization	**$986,966,567.60**	100.00%
Weighted Daily Conduit Debt Rate	0.4792%	
Weighted Daily Corporate Debt Rate	0.2048%	
Weighted Daily Total Debt Rate	**0.6840%**	

Daily Total Rate	Daily Corp Rate	)aily Conduit Rat	Daily JP Morgan Rate	Daily BOTM Rate	Daily Mizuho Rate	Sun Trust Rate	Daily RBC Rate	Daily Scotia Rate
0.6840%	0.8510%	0.6310%	0.66706%	0.55831%	0.59315%	0.44580%	0.82995%	0.69202%

Weekly Weighted Conduit Rate Calculation

Gotham — Bank of Tokyo - Mitsubishi

# of Days	Average A/R Balance	Total Cost	Average Yield	Average Cost	Weighted Cost
7	108,500,000.00	11,778.80	0.55831%	0.55831%	0.0931%

Jupiter — JP Morgan

Day	A/R Balance	Interest Rate	Average Cost	
7/6/2016	108,500,000.00	0.66110%	0.09444%	
7/7/2016	108,500,000.00	0.66460%	0.09494%	
7/8/2016	108,500,000.00	0.66710%	0.09530%	
7/9/2016	108,500,000.00	0.66710%	0.09530%	
7/10/2016	108,500,000.00	0.66710%	0.09530%	
7/11/2016	108,500,000.00	0.66910%	0.09559%	
7/12/2016	108,500,000.00	0.67335%	0.09619%	
	108,500,000.00		0.6671%	0.1112%

Working Capital — Mizuho

# of Days	Average A/R Balance	Total Cost	Average Yield	Average Cost	Weighted Cost
7	108,500,000.00	12,513.80	0.59315%	0.59315%	0.0989%

Thunder Bay Funding — RBC

# of Days	Average A/R Balance	Total Cost	Average Yield	Average Cost	Weighted Cost
7	108,500,000.00	17,509.67		0.82995%	0.1383%

Sun Trust

Day	A/R Balance	Interest Rate	Average Cost	
7/6/2016	108,500,000.00	0.44580%	0.06369%	
7/7/2016	108,500,000.00	0.44580%	0.06369%	
7/8/2016	108,500,000.00	0.44580%	0.06369%	
7/9/2016	108,500,000.00	0.44580%	0.06369%	
7/10/2016	108,500,000.00	0.44580%	0.06369%	
7/11/2016	108,500,000.00	0.44580%	0.06369%	
7/12/2016	108,500,000.00	0.44580%	0.06369%	
	108,500,000.00		0.4458%	0.0743%

on 7/14/16 change to .47935%. Will remain that until 8/11/16

Liberty Street — Scotia

Day	A/R Balance	Interest Rate	Average Cost	
7/6/2016	108,500,000.00	0.69004%	0.09858%	
7/7/2016	108,500,000.00	0.69301%	0.09900%	
7/8/2016	108,500,000.00	0.69413%	0.09916%	
7/9/2016	108,500,000.00	0.69413%	0.09916%	
7/10/2016	108,500,000.00	0.69413%	0.09916%	
7/11/2016	108,500,000.00	0.69323%	0.09903%	
7/12/2016	108,500,000.00	0.68545%	0.09792%	
	108,500,000.00		0.6920%	0.1153%

Total Avg A/R Balance
651,000,000.00

Total Weighted Yield 0.6310%

Daily Conduit Debt Rate 0.6310%

JP Morgan Weighted Rate	0.6671%
BOTM Weighted Rate	0.5583%
Mizuho Weighted Rate	0.5931%
Sun Trust Rate	0.4458%
RBC Weighted Rate	0.8300%
Scotia Weighted Rate	0.6920%

Kentucky Power Company
KPSC Case No. 2017-00179 General Rate Adjustment
Commission Staff's Post Hearing Data Requests
Dated December 13, 2017

DATA REQUEST

KPSC_PH_010 Provide a copy of the criteria utilized to determine when AEP personnel may use an AEP corporate jet, including cost justification and need.

RESPONSE

Please refer to KPCO_R_KPSC_PH_10_Attachment1.pdf for the current Use of Corporate Aircraft policy.

The use of aircraft for business purposes is widely recognized as essential to the effective and efficient management of both private businesses and state governments. Please see https://transportation.ky.gov/Aviation/Pages/Advantages-of-State-Aircraft.aspx

Witness: Ranie K. Wohnhas

AEP®

Title:	Use of Corporate Aircraft	**Date:**	1.18.16
Owner:	Robert Powers Chief Operations Officer	**Sponsoring Area(s):**	Aviation Services

Guideline Statement:

When used in conjunction with sound Business Continuity principles, the corporate aircraft are tools that allow AEP employees, board members and their third party advisors to conduct business in a safe, effective, and efficient manner. In addition, this tool allows AEP executives to maximize their time for the benefit of the corporation. The corporate aircraft are to be used only for business purposes unless specifically approved in accordance with this policy

Policies:

Pilot in Command

- The Pilot in Command is responsible for the safety of the crew and passengers as well as the condition of the corporate asset and will always have complete control over the decision to fly or not fly.

AEP Business Travel

- Use of company owned, leased and chartered aircraft (AEP Provided Aircraft) for AEP Business Travel is permitted for members of AEP's Chief Executive Officer Executive Management Team (CEOEMT).
- AEP Business Travel is defined as a trip where the primary purpose is integrally and directly related to the performance of the executive's, board member's or third party advisor's duties to AEP.
- The scheduling and use of AEP Provided Aircraft for AEP Business Travel by other employees requires the approval of a CEOEMT member.
- Use of AEP Provided Aircraft for any reason other than AEP Business Travel is discouraged but may be permitted for employees other than the CEO with the specific approval of the CEO on a trip by trip basis and for the CEO, with the specific approval of the Chairman of the Human Resources Committee of the Board of Directors.

Approvals

- The use of this service will require the approval of a CEOEMT member.
- The CEO approval is required for non-AEP employees use of corporate aircraft if there is no AEP employee aboard the aircraft on AEP Business Travel or if the non-AEP employee's travel has an incremental cost to the company.
- A CEOEMT member may approve the transportation of non-AEP employees if an AEP employee is aboard the aircraft on AEP Business Travel and the non-AEP employee's travel has no incremental cost to the company.
- As indicated above, use of AEP Provided Aircraft for any reason other than AEP Business Travel by employees other than the CEO requires the specific approval of the CEO on a trip by trip basis. Use of AEP Provided Aircraft by the CEO for any reason other than AEP Business Travel

requires the specific approval of the Chairman of the Human Resources Committee of the Board of Directors.

Business Travel with Spouse or a Guest

- With the approval of the CEO, spouses or guests of members of the CEOMT may travel on AEP Provided Aircraft if the primary purpose of the flight is AEP Business Travel and there is no incremental cost to AEP for the travel of the non-business passengers. Executives do not need to accompany their spouse or guest on an AEP Provided Aircraft provided they are both traveling to the same destination.

- For example, spouses or a guest may travel on AEP Provided Aircraft to AEP board meetings and industry meetings, if the trip qualifies as AEP Business Travel and there is no incremental cost to AEP for the spouse's or guest's travel. To determine if there is an incremental cost, AEP Aviation Services will include the cost of any required aircraft changes, additional aircraft and any necessary operational changes like fuel stops. Executives will pay any significant incidental costs resulting from the spouse's or guest's travel.

- CEOEMT approval is required for other employees to travel with a spouse or guest on AEP Provided Aircraft.

- Except in the unlikely situation where the employee's spouse is employed and compensated by the company as an employee or contractor and is required to actively participate in a business function, such as speaking on a business subject, the IRS considers travel on AEP Provided Aircraft by an employee's spouse or guest to be a taxable benefit. The value of this benefit and the tax withholding thereon will be calculated using the Standard Industry Fair Levels (SIFL) and withheld from the employee's pay. AEP no longer provides a tax gross-up to any employee or board member for the tax withholding of this value. Accordingly, AEP shall not require or expect the attendance of any employee's spouse or guest at any event that requires travel.

Personal Travel and Personal Stops on Business Trips

- The use of AEP Provided Aircraft for any travel other than AEP Business Travel or Emergency Travel is prohibited, unless approved by the CEO or, for the CEO, by the Chairman of the Human Resources Committee of the Board of Directors. The HR Committee of the Board of Directors and the Board of Directors has recommended that personal use of AEP Provided Aircraft not be provided as part of any future employment arrangement.

- Non-AEP Business Travel, irrespective of approval by the CEO or the Chair of the HR Committee, is likely to require reporting as a perquisite for the executive officers included in AEP's proxy statement. Non-AEP Business Travel is also likely to be considered to be a taxable benefit to the recipient, for which AEP is required to withhold taxes based on the SIFL methodology.

- SEC regulations require reporting of the incremental cost of using AEP Provided Aircraft for travel that is not AEP Business Travel as All Other Compensation for the executive officers included in AEP's proxy statement. It is the HR Committee of the Board of Directors' policy to generally prohibit travel that gives rise to such incremental costs. As such, the HR Committee of the Board of Directors has defined AEP Business Travel in accordance with the SEC definition of business travel. This definition is separate and distinct from the IRS definition of business travel and other definitions of business travel that may apply for other purposes. Any questions that arise as to what types of travel are AEP Business Travel will be determined by the AEP Legal Department based on whether or not such travel gives rise to an incremental cost under the SEC rules governing the reporting requirements for AEP's Proxy Statement, irrespective of whether the travel would be undertaken by or for an executive officer named in such table.

- Travel to attend outside public company, government and charity board meetings is generally not AEP Business Travel pursuant to this policy and is therefore generally prohibited, unless AEP legal determines that the trip is AEP Business Travel or the CEO approves the use of corporate aircraft for the trip. Travel to industry meetings such as EEI and INPO, is generally considered AEP Business Travel. Before scheduling corporate aircraft for travel that may not meet the definition of AEP Business Travel, executives are responsible for obtaining a determination from AEP Legal.

- Trips that include personal stops, regardless of stop duration and flight time, are not AEP Business Travel unless such stops have a business or aircraft operational purpose.

- Repositioning aircraft (deadhead legs) is considered AEP Business Travel only if repositioning the aircraft is required for AEP Business Travel. The cost of repositioning the aircraft is billed to the office of the CEO. Employees may fly as passengers during repositioning legs without bearing the cost of the flight so long as the employee does not influence the departure time, the route or the destination.

- Travel to or from an employee's second home, vacation destination or any residence other than the one nearest the employee's primary work location is generally not AEP Business Travel and is therefore generally prohibited unless approved by the CEO.

Emergency Travel

- AEP employees may use AEP Provided Aircraft for reasons other than AEP Business Travel in emergency situations with the approval of the CEO or, for the CEO, the approval of the Chairman of the HR Committee of the Board of Directors. Such travel is likely to be considered to be a taxable benefit, for which AEP is required to withhold taxes based on the SIFL methodology. The incremental cost to AEP is also likely to be required to be reported as a perquisite in AEP's proxy statement if used by an executive officer included in AEP's proxy statement.

Executive Travel Policy for Business Continuity

- Business Unit leaders should use sound Business Continuity principles when determining the passenger complement for corporate aircraft, commercial aircraft and ground transportation.

- No more than 4 CEOEMT members shall travel together

- CEO and COO shall not travel together on AEP aircraft, AEP supplied charter aircraft, or commercial aircraft. The CEO and COO may travel together on ground transportation.

- COO shall not travel with more than 2 of his/her direct reports at any one time

- CFO, Controller/CAO and Treasurer: only 2 of the 3 shall travel together

- No more than 3 executives holding the office of President of any AEP public utility operating company shall travel together

- EVP Generation, SVP-Fuels, Emissions & Logistics; VP, Engineering Services, VP Fleet Operations: only 3 of the 4 shall travel together

- EVP Energy Supply, SVP Commercial Operations, President AEP Energy Partners: only 2 of the 3 shall travel together

AEP®

Examples

- A Vice President in Generation needs to tour a new plant that is currently under construction with several members of her team. The trip can be accomplished in one day and the Vice President views the use of the corporate aircraft as a way to save time and travel expenses. ***The Vice President must obtain approval from the Executive Vice President of Generation.***

- Two members of the current contracted auditing firm are expected to make a presentation to the Board of Directors at an offsite board meeting. The auditing firm employees will be traveling aboard the corporate aircraft with several AEP employees. ***The transportation of the two non AEP employees must be approved by a CEOEMT member.***

- An AEP employee working storm duty approximately 1000 miles from home is critically injured in a traffic accident. The employee's supervisor would like to use the corporate aircraft to fly the injured employee's wife and two children to the city where the employee is hospitalized. Due to the timing of the flight, there will be no AEP employees aboard the aircraft. ***The CEO must approve this flight.***

- A Vice President in the Transmission group has been selected to receive a lifetime achievement award from an industry group in New York City. The Vice President's spouse will also be honored during the dinner. The Vice President must return to Columbus early the next day for an important meeting. ***The Executive Vice President of Transmission must approve the transportation of the Vice President's spouse.***

- A CEOEMT member is traveling to Europe for a family vacation. Due to the Executive Council members hectic work schedule, the Executive Council member has decided to meet his spouse in New York where both will depart on a commercial flight to London. The Executive Council member would like to use the corporate aircraft to fly from Columbus to New York. ***This flight is prohibited, unless specifically approved by the CEO.***

- A CEOEMT member has a vacation home in Tampa Florida. The Executive Council member is scheduled to attend a business conference in Naples Florida for one day during the middle of a five day scheduled vacation. The Executive Council member would like to use the corporate aircraft to fly to and from Tampa Florida and she will drive to the business conference in Naples Florida. ***This fight is prohibited, unless specifically approved by the CEO, since the primary purpose of the trip is not AEP Business Travel. The trip would be permitted if AEP Legal determined that the primary purpose was to attend the business meeting, as might be the case if it were a three day meeting with a two day weekend stay at the vacation home.***

- A CEOEMT member serves as a Director for a Fortune 50 company. The Executive Council member receives compensation to attend 10 meetings per year. The Executive Council member would like to use the corporate aircraft to fly to Atlanta to attend a Board meeting. ***This flight is not AEP Business Travel and is, therefore, prohibited, unless specifically approved by the CEO.***

- A CEOEMT member is on vacation in Florida, having flown there with her family on a commercial flight. Urgent business comes up unexpectedly while the executive is on vacation, and the CFO requests that she attend a meeting in New York City during her vacation. The corporate plane picks her up in Florida and takes her to the meeting in New York and returns her to Florida after the meeting. **This trip would be AEP Business Travel, but AEP Legal should generally be consulted to confirm that a trip is AEP Business Travel if it involves a vacation or a second home.**

- Aviation Services must reposition an aircraft to the Cook Nuclear plant in order to fly the Chief Nuclear Officer to an industry meeting. An employee in the Legal department needs to travel to Cook for a meeting on the day the aircraft is to be repositioned to Cook. The Legal department employee has no influence over the schedule of the flight and is able to fly as a passenger. **This flight is considered AEP Business Travel and the cost of the repositioning flight will be billed to the office of the CEO.**

Periodic Travel and Policy Review and Revision

- Senior AEP Management and the HR Committee of AEP's Board of Directors will periodically review use of AEP Provided Aircraft for both AEP Business Travel and other travel under this policy and may direct management to amend the policy as it deems appropriate.

Glossary

- The Chief Executive Officer Executive Management Team (CEOEMT) is comprised of all Senior Vice Presidents or above that report directly to the CEO along with all Executive Vice Presidents of AEPSC.

AEP®

Review / Revision:

Approval: Robert P. Powers
Robert Powers, EVP and Chief Operating Officer

Effective Date: 1/18/16

Review History:

Approval: Stanley E. Partlow
Stanley E. Partlow, Vice President and Chief Security Officer

Review Date: 1/17/16

Kentucky Power Company
KPSC Case No. 2017-00179 General Rate Adjustment
Commission Staff's Post Hearing Data Requests
Dated December 13, 2017

DATA REQUEST

KPSC_PH_011 Provide the number and composition of flight crews who operate AEP corporate jets.

RESPONSE

There are nine full time pilots employed by American Electric Power Service Corporation to operate the AEP corporate jets. The Federal Aviation Administration requires that each flight be crewed by two pilots.

Witness: Ranie K. Wohnhas

DATA REQUEST

KPSC_PH_012 Provide the total employments costs associated with flight crews who operate AEP corporate jets.

RESPONSE

Please see KPCO_R_KPSC_PH_12_Attachment1.xls for total employment costs for the flight crews. Employment costs are not allocated separately but instead are included as part of the total aviation costs allocated to Kentucky Power.

Witness: Ranie K. Wohnhas

DATA REQUEST

KPSC_PH_013 Provide the total aviation expense and the amount allocated to Kentucky Power for two years preceding the test year and the budgeted amounts for two years following the test year.

RESPONSE

The total aviation expense and the amount allocated to Kentucky Power for the test year and two years preceding are shown on KPCO_R_KPSC_PH_13_Attachment1.xls. The total test year aviation expense of $6,613,934 provided in response to KPSC 2-55 was for those flights for which Kentucky Power was either allocated or directly assigned costs. The total test year aviation expense shown on Attachment 1 to this response of $12,078,610 is for all flights. The difference of $5,464,676 represents flights for which no costs were allocated to Kentucky Power.

Kentucky Power's allocated amount from AEPSC was $400,750, of which $388,355 was assigned to O&M accounts as shown in response to AG 1-153. However, the net impact to Kentucky Power's cost of service is $293,300, of which $280,906 was assigned to O&M accounts. This is due to Kentucky Power billing Wheeling Power its 50% share for any flights that have some relationship to the Mitchell generating station.

Of the total $12,078,610 of aviation expenses during the test year, only $280,906 was in Kentucky Power's cost of service or 2.3%.

The budgeted amounts for total aviation expense for the two years following the test year are shown on KPCO_R_KPSC_PH_13_Attachment2.xls.

Witness: Ranie K. Wohnhas

DATA REQUEST

KPSC_PH_014 Provide the relocation expenses incurred by Kentucky Power for two years preceding the test year and the budgets amounts for two years following the test year.

RESPONSE

Relocation expenses for the two twelve month periods prior to the test year were:

Period	Kentucky Power Relocation Expenses
March 1, 2014 to February 28, 2015	$ 32,192
March 1, 2015 to February 29, 2016	$168,244

Kentucky Power's relocation expenses for the eight month period March 1, 2017 to October 31, 2017 totaled $125,736. Annualized over a twelve month period ending February 28, 2018 these expenses would be forecasted to total $188,604.

Relocation expenses are not budgeted as a disaggregated line item. Instead, relocation expenses are included in the total administrative and general expense budget level. Budgets are prepared on a calendar year basis. As a result, the requested budgeted levels of relocation expenses for the twelve month periods ended February 28, 2018 and February 28, 2019 (or the calendar years 2018 and 2019) are not available. Kentucky Power is actively recruiting top talent to help lead its regulatory and business operations in the Commonwealth. As the Company continues to succeed in locating new industry more opportunity arises for current employees to be recruited away to other states and for Kentucky Power to recruit new talent with fresh ideas to Kentucky. The Company intends to be active in recruiting talented staff to lead Eastern Kentucky; meaning that although there is not a single identified budget for relocation there is a high likelihood that the Company will continue to relocate employees and executives to the region. As such, past years data may not be representative.

A test year represents a snapshot of a utility's operations during a twelve month period. Implicit in the test year concept is that although the individual items comprising the test year may vary in amount from year-to-year, these variances tend to cancel each other out. Thus, except for known and measurable changes, an otherwise proper test year should provide a reasonably accurate picture of the utility's operations. It thus is inappropriate to take a single expense, such as Kentucky Power's relocation expense, and average it, while leaving other expenses that may vary similarly, but whose average trends in the opposite direction, unchanged. Doing so skews the test year and renders it less useful for establishing rates. It thus would be improper to reject the test year level of relocation expenses and instead to use an average level of Kentucky Power's relocation expenses for the purpose of establishing the Company's revenue requirement without making similar adjustments to each of the Company's expenses.

Further, each calendar year the Company establishes a target total O&M level to which it manages it operations. As the year progresses and the Company monitors its O&M spending, Kentucky Power adjusts various expenses in an effort to stay within its overall O&M level. When expenses levels increase in certain areas (like relocation costs) the Company works to decrease other O&M expense areas in order to stay within its targeted overall O&M level. This same effort occurred during the test year; the Company adjusted other prudent and reasonable budgeted costs to offset the relocation spending. Adjusting a single expense, such as relocation expenses, to an average ignores the manner in which the Company operates and penalizes Kentucky Power for managing its overall expenses. With relocation costs being higher than average for the test year, the Company worked to decrease O&M expenditures in another area in order to stay at its targeted O&M levels.

Witness: Ranie K. Wohnhas

DATA REQUEST

KPSC_PH_015 Provide the revised AEV-3S in Excel spreadsheet format with formulas intact and unprotected, and all rows and columns fully accessible.

RESPONSE

Please see KPCO_R_KPSC_PHDR_15_Attachment1.xls for the requested information.

Witness: Alex E. Vaughan

DATA REQUEST

KPSC_PH_016 Refer to Kentucky Power's response to Commission Staff's Fourth Request for Information, Item 6, Attachment KPCO_R_KPSC_ 4_006_Attachment1 .xlsx. Revise the schedule to reflect actual amounts of employer contributions to all types of health insurance in Column E, which is labelled Blended Funding (3). Include any Company contributions to HSA, HRA, or other employee accounts that serve to reduce employee costs or deductibles.

RESPONSE

Please see KPCO_R_KPSC_PH_16_Attachment1.xlsx.

Witness: Tyler H. Ross

DATA REQUEST

KPSC_PH_017 Refer to Kentucky Power Hearing Exhibit 13, Settlement Revenue Allocation, the section at the bottom of the exhibit with lines labelled LGS, PS, and Total. Continue the data contained on the lines labelled LGS, PS, and Total to include columns labeled Current ROR, Proposed ROR, and Proposed Non-Fuel Base Revenue Increase.

RESPONSE

Please see KPCO_R_KPSC_PHDR_17_Attachment1.xls for the requested information.

Witness: Alex E. Vaughan

DATA REQUEST

KPSC_PH_018 Refer to Commission Staff Hearing Exhibit 5. Provide the transmission projects included in AEP's expected $9 billion transmission investment between 2016 and 2019, indicating which transmission projects that are located in the AEP transmission zone in the PJM Interconnection, Inc. footprint and which are located outside the AEP transmission zone. For each project, indicate whether it is a baseline or supplemental project.

RESPONSE

AEP's 2017 to 2019 investment in transmission projects is estimated to be approximately $9 billion total. The portion of the investment outside the PJM footprint is estimated to be $3 billion, of which the Company's Kentucky retail customers will not be allocated any of the associated costs.

Of the $6 billion that is forecasted to be invested in PJM, approximately $1.8 billion is for non-topology changes such as equipment failure replacements, physical and cyber security, telecom, and SCADA upgrades. Approximately $4 billion is estimated for PJM baseline and supplemental projects. Please refer to KPCO_R_KPSC_PH_18_Attachment1.xlsx for a listing of PJM projects greater than $500,000 included in the estimated $6 billion transmission investment within the PJM RTO to be made by the AEP Companies. In addition, approximately $11 million is forecasted for projects totaling under $500,000.

Project cost estimates are based on varying stages of engineering design and could change. Please note that the timing and composition of projects may change and additional/different projects may be constructed during the period from January 1, 2017 through December 31, 2019.

Witness: Alex E. Vaughan

DATA REQUEST

KPSC_PH_019 Provide the amount of Kentucky Power's adjusted test-year revenue requirement for its transmission assets assuming a 9.75 percent return on equity and 9. 11 percent weighted average cost of capital.

RESPONSE

Utilizing a 9.75 percent return on equity and 9.11percent weighted average cost of capital as set forth in the Settlement Agreement, the retail transmission cost of service would be $50.3 million. The PJM OATT transmission owner revenue credit in base rates is $59.5 million, resulting in a net Kentucky Retail base rate transmission cost of service of $-9.2 million (credit to customers). Please see KPCO_R_KPSC_PH_19_Attachment1.xlsfor the calculations.

Witness: Alex E. Vaughan

DATA REQUEST

KPSC_PH_020 Provide the calculation of the updated monthly environmental base rate amounts in the same format used in Kentucky Power's response to Staff's Third Request for Information, Item 9, and an updated AJE-1 S reflecting Tariff ES Base Period Revenue Requirement. Provide the information in Excel spreadsheet format with all cells and formulas unprotected and fully accessible.

RESPONSE

Please refer to KPCO_R_KPSC_PH_ 20_Attachment1.xls for the requested information. In addition to the update for the weighted average cost of capital, the environmental base revenue requirement has been updated to reflect the depreciation rates for account 312 as set forth in Exhibit 5 to the Settlement Agreement.

Witness: Amy J. Elliott

DATA REQUEST

KPSC_PH_021 Refer to the Commission's Order dated August 3, 2017, that denied a request to intervene filed by Progress Metal Reclamation Company d/b/a Mansbach Metal Company ("Progress"). Explain what steps Kentucky Power has taken to work with Progress to identify economic development options that assist existing businesses.

RESPONSE

Kentucky Power Company began working diligently with Progress Metal Reclamation Company (Mansbach) in late July 2017 to identify economic development and other options to retain Mansbach as a customer of Kentucky Power. A summary of those efforts is outlined below.

July 27, 2017: Mansbach requested a meeting with Ken Borders, Customer Service Engineer, Kentucky Power Company, to discuss an interruptible tariff. Attending the meeting were Mr. Borders, Matt Hart, Mansbach, and Dale Rector, a consultant with Cumulus Energy. During the meeting Mansbach requested that the Company provide interval data. Mr. Rector requested Mr. Borders to forward two proposals to the Company's regulatory department. The first was a request to purchase power at wholesale from PJM based on the AEP hub LMP. The second was a request to eliminate or reduce the 60% minimum demand ratchet for customers who are able to shift load exclusively to off-peak.

July 28, 2017: A conference call took place to further discuss and answer questions about the interruptible process. The Company agreed to draft an addendum to its contract for interruptible service.

August 24, 2017: Dale Rector requested a meeting scheduled for September 28, 2017 to address proposed changes to the Company's Tariff E.D.R. to provide benefits to Mansbach. In the interim, Kentucky Power reviewed Mr. Rector's proposal concerning changes to Tariff E.D.R. and prepared a contract and addendum for the interruptible tariff. A draft of the contract documents, based on the July 27th and 28th conversations, was sent to Mansbach and Mr. Rector for their review prior to the September 28th meeting.

September 28, 2017: Kentucky Power personnel (Ranie Wohnhas, Managing Director Regulatory and Finance, Delinda Borden, Director Customer Services and Ken Borders) met with Mr. Hart and Mr. Rector, from Mansbach, at the Kentucky Power State Office in Ashland. During the meeting Mr. Rector discussed his proposal to add or modify Tariff E.D.R. to provide reduced rates and other tariff changes beneficial to existing customers not planning to add load, and who claim they would be unable to continue to operate at the tariffed rates.

Kentucky Power, while recognizing the benefits of retaining existing load, identified multiple concerns with the fairness and workability of the proposal. Specifically, in the absence of an externally-verifiable metric such as additional load, Kentucky Power would be required to investigate and make decisions concerning the financial plans and condition of each existing customer applying for service pursuant to the proposed economic development rider to ensure its application the existing customer was fair to other customers. At a minimum, any such tariff would require Kentucky Power to determine whether the existing customer could continue to operate at tariffed rates by modifying the nature of their operations, becoming more efficient, or changing the nature of their service or operation. These are not decisions the Company should be required, or necessarily is equipped, to make. The Company also would be placed in the position of picking winners and losers. Kentucky Power shared that Mansbach had the opportunity to take advantage of existing tariffs to reduce cost by taking service through the interruptible rate or by operating at off-peak rates. However, the Company agreed to take another look at Mansbach's proposal based on some information provided during the meeting. Also during this meeting, Mansbach was provided a contract and addendum for the interruptible tariff.

October 11, 2017: Mr. Wohnhas sent a letter via email to Mr. Hart and Mr. Rector summarizing the Company's response to the concerns raised by Mansbach and what the Company could or could not do in relation to all of the issues that had been presented by Mansbach. That letter is attached as KPCO_R_KPSC_PH_21_Attachment1.pdf.

October 17, 2017: Mr. Hart, Troy Blanton and Jerry Frost of Columbus Recycling of Columbus, MS requested the presence of Ken Borders, Customer Service Engineer at a meeting in the Mansbach offices. Matt Hart indicated that Columbus Recycling was in talks to purchase Mansbach from Progress Metals Reclamation Co. During the meeting, Mr. Blanton and Mr. Frost asked questions about the Company's tariffs and asked if Kentucky Power would provide a below tariff rate. Kentucky Power explained the nature of the regulatory process, that the tariffs are approved by the Kentucky Public Service Commission, and the limits on the Company's ability to provide service at non-tariffed rates. Kentucky Power recommended that Mansbach take advantage of time of day rates or pursue an interruptible tariff.

November 13, 2017: Ken Borders and Delinda Borden met with Matt Hart, Jerry Frost, and Troy Blanton at Mansbach offices. During this meeting the Company was informed that Columbus Recycling Holding Co. had purchased the assets of Progress Metal Reclamation Co. Mr. Frost asked if there were any means to negotiate a better rate with Kentucky Power. Kentucky Power offered Columbus Recycling the interruptible rate and provided its representatives a sample contract based on the agreement prepared for Progress Metal Reclamation. Again, the Company discussed the fact the Company's tariffed rates were Commission-approved. Kentucky Power also discussed Mansbach's load profile and provided interval data that could be used to manage its operations and load and thereby lower power costs. Kentucky Power also provided Columbus Recycling the billing for the crusher and shearer accounts for several prior months and discussed process improvements Mansbach could implement. These included reducing power demand spikes when operating its equipment to levelize its peak demand charge and lower its bill amounts.

November 30, 2017: Brad Hall, Manager External Affairs and Ken Borders met with Matt Hart, Jerry Frost, and Troy Blanton with Columbus Recycling Holding Company, LLC at the Mansbach offices in Ashland. Kentucky Power provided Columbus Recycling a contract and an addendum for the interruptible rate. Columbus Recycling also inquired about combining its shearer and crusher loads into one account and had asked if doing so would provide savings. The Company indicated that although an earlier estimate showed some savings, varying demands and usage scenarios could affect any savings. The Company offered to provide another estimate.

December 6, 2017: Kentucky Power provided the estimate promised Mr. Frost on November 30, 2017.

As of the submission of this response, Columbus Recycling has not signed the interruptible agreement. Kentucky Power is working with Columbus Recycling to ensure it has the information it requires concerning its accounts and that the accounts are transferred in its name.

The continued communication between, and efforts by, the Company and Mansbach demonstrates the willingness of both parties to work toward a solution to retain Mansbach as a customer of Kentucky Power.

Witness: Ranie K. Wohnhas

KENTUCKY POWER
An AEP Company
BOUNDLESS ENERGY™

Kentucky Power Company
855 Central Avenue
Suite 200
Ashland, KY 41101
606-327-2600

October 11, 2017

Dale/Matt:

This letter is a follow-up to our meeting held in Kentucky Power's offices on September 28, 2017. I would like to thank you for the open and transparent discussions we had in reference to Progress Metal Reclamation Company ("Mansbach"). At the end of our discussions I promised to have further discussions with our management as to what could be done to assist Mansbach with its bill level.

Let me first address a few concerns presented by Mansbach during our September 28th meeting. First, Mansbach had a concern with the approximate $5/kW increase in the demand charge that Kentucky Power requested in its current rate application that is before the Commission (Case No. 2017-00179). Mansbach takes service on the Company's tariff ICS at sub-transmission voltage. The proposed increase to the on-peak demand charge was $5.54/kW ($15.56 - $10.02). However, because the test year tariff Big Sandy 1 Operations Rider (BS1OR) and the non-FGD environmental surcharge were rolled into our base rates ($1.14/kW and $1.55/kW respectively), the increase is only $2.85/kW ($5.54 - $1.14 - $1.55). With Mansbach selecting to be interruptible as part of tariff CS-IRP and taking advantage of the $3.68/kW credit per month, the percent increase when new rates would go into service would be 5.5% over current billing.

Second, Mansbach also stated a concern that there was a lack of investment being made in the distribution system serving the facility. However, our records indicate some significant investment to the system serving your facility. In fact, in January 2005, the Company invested $322,100 to install a 69kV extension to serve the new shredder at no cost to the customer.

Third, there were some discussions around the Company's tariff Contract Service Coal Power ("CS Coal") which was specifically designed and approved by the Commission to encourage coal companies to re-open their facilities. I wanted to make sure you were aware that the CS Coal tariff encompasses many of the same alternatives being offered to Mansbach (off-peak hours, CS-IRP, deposit language, etc.) all for the purpose of retaining, if possible, customers.

With those clarifications, allow me to lay out the two options that Kentucky Power feels are most appropriate under our current tariffs:

1. **Off-Peak Operation:** In reviewing Mansbach's account history, it shows an opportunity for savings by conducting the operations off-peak. This is a measure completely under Mansbach's control as a process change. Mansbach previously took advantage of this strategy by shifting its peak load to off-peak for fourteen months (Oct. 2015 – Nov. 2016). That effort produced an average monthly savings of $17,562 or a total of $245,868 over the fourteen month period. By shifting back peak load to on-peak for the ten months since November 2016, Mansbach has missed out on approximately $175,620 in savings.

2. **CS-IRP:** If Mansbach wants to operate during peak demand time periods then it can become an interruptible customer on the CS-IRP tariff. This should provide an approximate $220,800 in annual savings. If Mansbach is unable to operate their peak load during off-peak hours, then the CS-IRP allows operations to continue during on-peak hours and gives them a greater cost reduction. As shared previously, this is an option that Company representatives raised in the past, but Mansbach had yet to take advantage; however, we are in current discussions on a special contract addendum to file with the Kentucky Public Service Commission for the CS-IRP option.

The Company is open to work with Mansbach to provide reliable service at a reasonable cost. The options presented above are the best options available under the current system. Any other option would go beyond our approved tariffs and require special Commission approval. Mansbach's proposals to revise the current tariff EDR did not provide a workable solution when looking at Kentucky Power's entire C&I customer base.

Thank you for the discussion and joint effort to explore options. I know that the two options laid out in this letter may not meet with your hope for a greater decrease in your overall rates. Unfortunately, our discussions did not lead to an option that Kentucky Power can support beyond these measures. Should you have another idea you would like us to consider, please provide it to me so that we can have it reviewed by our team.

Sincerely,

Ranie Wohnhas
Managing Director, Regulatory and Finance

DATA REQUEST

KPSC_PH_022 State whether Kentucky Power will place its proposed rate adjustment into effect subject to refund if the Commission has not entered a final Order in this matter by January 18, 2018, which is the suspension date for the proposed rates.

RESPONSE

If the Commission has not entered a final order in this matter by January 18, 2018 Kentucky Power will place its proposed rates into effect in accordance with KRS 278.190(2). Kentucky Power is hopeful the Commission will issue a decision approving the balance presented in the settlement prior to that date, but will implement the requested rates in the absence of an Order. To aid the Commission in reaching a decision by the end of the suspension period, Kentucky Power is filing its data request responses two days early.

Kentucky Power must implement rates at the end of the suspension period to provide the Company an opportunity to earn a fair return under the regulatory compact. Kentucky Power forecasts it will earn a 4.6% to 4.8% return on equity in 2017 with its current rates. This return on equity is 55% to 53% below the 10.25% return on equity authorized for the environmental surcharge and Big Sandy Retirement Rider in Case No. 2014-00396. It also is at least 48% below the low point of the 9.3% to 10.3% range the Commission found reasonable in the same case. As such, the current rates are confiscatory and deny Kentucky Power the opportunity to earn a fair, just, and reasonable return on equity as required by both the Constitution and KRS 278.030.

Witness: Matthew J. Satterwhite

DATA REQUEST

KPSC_PH_023 Please refer to Section 18 (Tariff Sheet 2-10) of the Company's proposed terms and conditions of service that were filed with the Company's application. Mr. Sharp offered upon cross examination to refile Section 18 to clarify the Company's intent with respect to denial and discontinuance and service. Please provide the revised tariff language.

RESPONSE

Kentucky Power is providing the following revised tariff language for Section 18 (Denial or Discontinuance of Service) of the Company's Terms and Conditions of Service:

Service will not be supplied or continued to any premises if at the time of application for service the Applicant is merely acting as an agent or person or former customer who is indebted to the Company for service previously supplied at the same, or other premises, until payment of such indebtedness shall have been made.

Witness: Stephen L. Sharp