COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

MAY 10 2012

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY)
FOR APPROVAL OF ITS ENVIRONMENTAL)
SURCHARGE PLAN, APPROVAL OF ITS AMENDED)
ENVIRONMENTAL COST RECOVERY) CASE NO. 2011-00401
SURCHARGE TARIFFS, AND FOR THE GRANT OF)
CERTIFICATES OF PUBLIC CONVENIENCE AND)
NECESSITY FOR THE CONSTRUCTION AND)
ACQUISTION OF RELATED FACILITIES)

RESPONSES OF KENTUCKY POWER COMPANY TO
COMMISSION STAFF'S APRIL 30, 2012 PUBLIC HEARING DATA REQUESTS

May 9, 2012

VERIFICATION

The undersigned, John M. McManus, being duly sworn, deposes and says he is Vice President Environmental 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

John M. McManus

John M. McManus

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 7 day of May 2012.

Janet L. White

Notary Public

JANET L. WHITE
Notary Public, State of Ohio
My Commission Expires 06-09-2013

My Commission Expires: ____________

VERIFICATION

The undersigned, Lila P. Munsey, being duly sworn, deposes and says she is the Manager, Regulatory Services for Kentucky Power, that she has personal knowledge of the matters set forth in the forgoing responses for which she is the identified witness and that the information contained therein is true and correct to the best of her information, knowledge, and belief

Lila P. Munsey

Lila P. Munsey

COMMONWEALTH OF KENTUCKY	)	
	)	Case No. 2011-00401
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lila P. Munsey, this 8th day of May 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

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. 2011-00401
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 9th day of May 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

Kentucky Power Company

REQUEST

Refer to the Company's 2010 Financial Report as filed with the Commission.

(a) Please provide the tons of coal burned at Big Sandy Unit 1 and Big Sandy Unit 2 during 2010. For each unit calculate the percentage that unit's consumption of coal represented of the total amount of coal consumed at Big Sandy during 2010.

(b) Please provide the cost of the coal burned at Big Sandy Unit 1 and Big Sandy Unit 2 during 2010. For each unit calculate the percentage that unit's consumption of coal represented of the total cost of coal consumed at Big Sandy during 2010.

RESPONSE

KPCo does not separately track coal consumption or cost on a unit basis.

(a) However, the estimated coal 2010 annual consumption by unit for Big Sandy Unit 1 is 375,889 tons (or 14.6%), and 2,198,096 tons (or 85.4%) for Big Sandy Unit 2. This estimate is based on total 2010 coal consumed for the Big Sandy Plant as reported through KPCo's 2010/Q4 FERC Form 1, page 402 and NERC GADS unit generation and heat rate information for each unit for that year. Unit generation and heat rate from NERC GADS were used to calculate the total heat input for each unit, and the ratio of unit heat input to total heat input was applied to the total plant coal consumption to calculate the per unit consumption, since both units consume the same coal.

(b) Based on its 2010/Q4 FERC Form 1, page 402, KPCo's total fuel cost for 2010 including oil and transportation was $174.9 million, of which $1.624 million was for oil. Of the $173.3 million in coal costs, approximately $148.0 million (85.4%) would have been attributable to Big Sandy Unit 2 and approximately $25.3 million (14.6%) attributable to Big Sandy Unit 1.

It should be noted that the 2010 Kentucky Power Utility Financial Report showed a total fuel cost of $174.0 million for KPCo in 2010. The difference between the FERC Form 1 and the Kentucky Power Utility Financial Report (approximately $0.9 million) is attributable to deferred fuel.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide the current prices of 1.7 lbs SO2/MMBTU coal and 4.5 lbs SO2/MMBTU coal and calculate the difference between the two. Using Big Sandy Unit 2's consumption of coal in 2010, and current prices for 1.7 lbs SO2/MMBTU coal and 4.5 lbs SO2/MMBTU coal, please calculate the difference in the cost of coal consumed in Big Sandy Unit 2 would have been if it had been able to burn 4.5 lbs. SO2/MMBTU coal during 2010.

RESPONSE

The installation of a scrubber will allow KPCo to expand the sulfur range of fuel purchased for Big Sandy Unit 2. Two potential fuel combinations with the scrubber installation are either to purchase a 4.5 lb sulfur coal that could be consumed with no blending, or purchase and blend high sulfur (7.5 lb SO2) and low sulfur (1.7 lb SO2) coal to achieve a 4.5 lb sulfur coal mixture. Regardless of the fuel purchased, it must meet the other operational parameters and constraints of the unit. The following calculation shows the costs of each approach, based on the current market projections for 2013. KPCo would evaluate all of the fuel options available and make purchase decisions based on providing fuel at the lowest reasonable cost.

The coal prices used are from SNL Energy's, April 30, 2012 Weekly Coal Report, as such market data would most closely represent the historical KPCo procurement practice.

The prices as published on a per ton basis for the third and fourth quarters of 2012, as well calendar year 2013 are shown in Table 1 below. In reviewing the comparisons, it should be understood that Q3 2012 and Q4 2012 coal price data represent values that are closer to spot market purchases, whereas the calendar year 2013 price is more representative of a price that may be seen in response to a longer-term solicitation. In addition, Q3 and Q4 2012 coal market prices are affected by a current lack of market activity by many coal consumers. This has driven current coal prices below levels that are expected to be seen in future years.

Table 1

Coal Region	BTU/lb	lb SO2/MM BTU	Q3 2012	Q4 2012	Calendar Year 2013 Price
CAPP	12,500	1.5	$59.30	$61.60	$68.00
Pittsburg Seam	13,000	4	$58.00	$58.25	$58.60
NAPP	12,500	7.5	$48.25	$48.50	$48.75

A comparison of the 2010 actual fuel cost and the market data presented above is included in Table 2 on page 3 of this response.

Savings Based on Q3 2012 SNL Pricing	$147,993,394	Calculated 2010 Big Sandy Unit 2 Coal Cost as Calculated in KPSC H-1
	$126,186,354	Coal Cost Based on a 4 lb SO2/MMBTU Pittsburg Seam Coal
	$21,807,039	Estimated Fuel Savings Based on Pittsburg Seam Coal
	15%	Percentage Estimated Savings Over 2010 CAPP Cost
	$121,674,104	Coal Cost Based on a 50:50 Blend of CAPP and NAPP Coals
	$26,319,289	Estimated Savings based on 50:50 CAPP:NAPP Blend
	18%	Percentage Estimated Savings Over 2010 CAPP Cost
Savings Based on Q4 2012 SNL Pricing	$147,993,394	Calculated 2010 Big Sandy Unit 2 Coal Cost as Calculated in KPSC H-1
	$126,730,261	Coal Cost Based on a 4 lb SO2/MMBTU Pittsburg Seam Coal
	$21,263,133	Estimated Fuel Savings Based on Pittsburg Seam Coal
	14%	Percentage Estimated Savings Over 2010 CAPP Cost
	$124,558,985	Coal Cost Based on a 50:50 Blend of CAPP and NAPP Coals
	$23,434,408	Estimated Savings based on 50:50 CAPP:NAPP Blend
	16%	Percentage Estimated Savings Over 2010 CAPP Cost
Savings Based on Calendar Year 2013 SNL Pricing	$147,993,394	Calculated 2010 Big Sandy Unit 2 Coal Cost as Calculated in KPSC H-1
	$127,491,730	Coal Cost Based on a 4 lb SO2/MMBTU Pittsburg Seam Coal
	$20,501,663	Estimated Fuel Savings Based on Pittsburg Seam Coal
	14%	Percentage Estimated Savings Over 2010 CAPP Cost
	$132,082,303	Coal Cost Based on a 50:50 Blend of CAPP and NAPP Coals
	$15,911,091	Estimated Savings based on 50:50 CAPP:NAPP Blend
	11%	Percentage Estimated Savings Over 2010 CAPP Cost

It must be further noted that applying forward looking coal prices to historical consumption requires many assumptions, including:

- The 2010 Unit 2 Fuel Cost includes coal and transportation.
- The cost projections for the market are for coal only and do not include transportation (including such costs would reduce the above stated savings).
- The cost savings is solely based on the cost of the fuel and does not take into account other costs that might be associated with a scrubber, such as the cost of chemicals.
- The current coal market for 2013 is different from the market that existed in 2010 and the market when such fuel purchases are executed for KPCo will also be different.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please verify that the credit side of the monthly AFUDC amounts will be reflected as a revenue item in the Company's monthly income statement. Please verify that the monthly credit AFUDC amount increases the Company's monthly net income and the Company's earned return during the construction period.

RESPONSE

The credit side of the monthly AFUDC amount **is not** a revenue account but rather a interest expense account. Further, when considering **only** the effect of AFUDC entries, the credit side of the monthly AFUDC entry as an interest expense account results in an increase to a utility company's net income. **However**, a complete analysis would show that the debt-related AFUDC simply offsets a portion of the interest expense already recorded by the utility company. Commonly, the interest expense being offset by AFUDC-Debt is recorded in Account 427 – Interest on Long-Term Debt, 430 – Interest to Associated Companies, and/or 431 – Other Interest Expense. Thus, the monthly net effect of increased interest expense offset by AFUDC typically provides a **decrease** to net income.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

The Big Sandy SCR went into service in May 2003. Please state whether the Big Sandy SCR costs were included in the Company's monthly environmental report for the May 2003 expense month.

RESPONSE

Yes, the costs associated with the Big Sandy SCR were included in the Company's monthly environmental report for the May 2003 expense month.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Please provide by unit the current net book value and the remaining useful lives of Big Sandy Units 1 & 2.

RESPONSE

Plant balances are not available by unit, only by total plant. The values could be allocated to the two units based on their respective MW. The composite depreciation rate for Big Sandy is 3.78%. The undepreciated plant balance, or the net book value, as of March 31, 2012 is as follows:

$549,494,999	Original Cost
$270,657,716	Accumulated Depreciation
$278,837,283	Net Book Value

Big Sandy Unit 1 is expected to retire no later than June 1, 2015. As of April 30, 2012, the length of time remaining for the undepreciated portion of Big Sandy Unit 1 is approximately 37 months. An estimated retirement date for Big Sandy Unit 2 has not been established.

Nevertheless, if the Company's application is granted, Kentucky Power expects to continue to operate Big Sandy Unit 2 until 2040. This would yield a remaining life of approximately 28 years.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide the date, amount and reason for the last capital infusion by American Electric Power Company, Inc. into Kentucky Power Company.

RESPONSE

The last capital (equity) infusion from AEP to Kentucky Power was in the first quarter of 2009 of $30 million. The infusion was made to strengthen Kentucky Power's capital structure and help maintain its financial ratios.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

What other options were considered prior to the February 10, 2012 filing seeking approval to transfer 20% of Ohio Power Company's Mitchell Units 1 & 2 to Kentucky Power?

RESPONSE

The other options considered prior to the FERC filing on February 10, 2012 are detailed in the Company's response to KPSC 3-1.

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY

REQUEST

Please provide a copy of the KPCo Unit Power Agreement for Rockport. When does the agreement expire? Does the contract permit either party to terminate the agreement before that date?

RESPONSE

A copy of the Kentucky Power Company (KPCo or Kentucky Power) Unit Power Supply Agreement (UPSA) for Rockport is attached. The agreement is between KPCo and AEP Generating Company and is on file at FERC as the AEP Generating Company First Revised Rate Schedule FERC No. 2, approved in FERC Docket No. ER05-141-000, with an effective date of January 1, 2005.

According to the KPSC Order in Case No. 2004-00420 dated December 13, 2004 (Kentucky Case), the Rockport purchase power contract was extended through December 7, 2022. See numbered paragraph 6 of the UPSA. According to the Stipulation and Settlement Agreement (SS&A) in the Kentucky Case, with the exception as provided in Section VI(3) of the SS&A, neither KPCo nor any of its affiliates, not any party to the SS&A will seek to have the UPSA terminated before its new expiration date of December 7, 2022.

The exception in Procedural Terms Section VI(3) of the SS&A provides that if, at any time prior to the expiration of the extension of the UPSA, the Kentucky PSC or its successor enters an Order that prevents Kentucky Power from charging rates consistent with the provisions of Sections III(1)(a), Section III(1)(b), III(1)(d)(i) and III(1)(d)(ii) of the SS&A, then Kentucky Power may, upon 120 days' notice to the Commission and the parties to this SS&A, begin legal or regulatory proceedings necessary to terminate the extension of the UPSA and withdraw from all other obligations under this Agreement. See, also, numbered paragraphs 2.1 and 2.2 of the UPSA.

WITNESS: Ranie K. Wohnhas

AEP GENERATING COMPANY
<u>FERC RATE SCHEDULE NO. 2</u>

UNIT POWER SERVICE

TO

KENTUCKY POWER COMPANY

EFFECTIVE: FOR DEMAND AND ENERGY RELATED CHARGES ON OR ABOUT DECEMBER 1, 1984, THE DATE OF COMMERCIAL OPERATION OF UNIT NO. 1 AT THE ROCKPORT PLANT

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 1.2 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 Related 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 (Account 231), Preferred Stock (Accounts 204-206), and Common Equity less any Temporary cash Investments, Special Deposits and Working Funds (Accounts 132-134 and 136) 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 a provision for depreciation and amortization (Accounts 403-407), 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 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' interests, 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 challenge 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); less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111); 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); 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 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 107) 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 Unit No. 1 and Common Facilities plus the Net In-Service investment associated with Unit No. 2.

4. Net In-Service Investment

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), 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), 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 less Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253), 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), 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), Other Deferred Debits (Account 186 pursuant to Note 4.D. below), 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 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 a 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:

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

Where:

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

and

$$\text{Curtailment equivalent outage hours} = \text{The product for each curtailment of:}$$

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

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. <u>Investment Balances</u>

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 books 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. <u>Allocation of Expenses</u>

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 costs, 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 charged 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

Pg 2 of 18

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	+ Operation and Maintenance Expenses	
8	+ Depreciation Expense	
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 and State 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 Deferred Federal and State Income Taxes	
21	= Total Unit 1 Federal and State Income Taxes	
22	Proof of Federal Income Tax :	
23	Total Unit 1 Annual Power Bill	
24	- Operation and Maintenance Expenses	
25	- Depreciation Expense	
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 Deferred Federal and State Income Taxes	
	= Total Unit 1 Federal and State Income Taxes	
35		

* From Page 5 of 18 : Line 21 + (Line 28 x Line 31 x Line 32)

AEP GENERATING COMPANY
SAMPLE POWER BILL
OPERATING RATIO

Pg 3 of 18

Line No		Amount
1	Operating Ratio:	
2	Net In-Service Investment:	
3	Electric Plant In-Service	
4	- Accumulated Depreciation	
5	+ Materials and 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	- Other Deferred Credits (A/C 253)	
12	- Accumulated Deferred FIT	
13	- Accumulated Deferred ITC	
14	Total Net In-Service Investment	
15	Non-In-Service Investment - CWIP	
16	Construction Work In Progress	
17	+ Materials & Supplies	
18	- Accumulated Deferred FIT	
19	Total Non-In-Service Investment - CWIP	
20	Non-In-Service Investment - Other :	
21	Plant Held for Future Use (A/C 105)**	
22	+ Other Deferred Debits (A/C 186) **	
23	+ Fuel Invent. Over Allowed Level ****	
24	Total Non-In-Service Investment - Other	
25	Total Investment (Lines 14+19+24)	
26	Operating Ratio (Line 14/Line 25)	
27	Non-In-Service Investment - CWIP Ratio (Line 19/Line 25)	
28	Non-In-Service Investment - Other Ratio (Line 24/Line 25)	
29	Total Investment	

* As permitted by FERC
** Excluding Amount 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

Pg 4 of 18

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	- Other Deferred Credits (A/C 253)	
12	- Accumulated Deferred FIT	
13	- Accumulated Deferred ITC	
14	Total Unit 1 Net In-Service Investment	
15	Unit 2 Net In-Service Investment	
16	Electric Plant In-Service	
17	- Accumulated Depreciation	
18	+ Materials & Supplies	
19	+ Prepayments	
20	+ Plant Held For Future Use (A/C 105)*	
21	+ Other Deferred Debits (A/C 186)*	
22	+ Other Working Capital **	
23	+ Unamortized Debt Expense (A/C 181)	
24	- Other Deferred Credits (A/C 253)	
25	- Accumulated Deferred FIT	
26	- Accumulated Deferred ITC	
27	Total Unit 2 Net In-Service Investment	
28	Total Net In-Service Investment	
29	Net In-Service Investment Ratio:	
30	Unit 1 (Line 14/Line 28)	
31	Unit 2 (Line 27/Line 28)	

* 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 COMMON EQUITY & OTHER CAPITAL RETURNS

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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)	
25	+ Short-Term Debt Interest Expense (a/c 431)	
26	+ Other Interest Expense (a/c 428-431)	
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 6 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

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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 (151.20)	
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/75 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 75 Days	
20	= 75 Days Supply (Tons)	
21	x Coal Cost per Ton (151.10 at End of Prior Month)	
22	= 75 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	454.10	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		Total Other Operating Revenues	

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

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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 Expense - 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 EXPENSE & AMORTIZATION EXPENSES

Line No.	Account No.	Description	Amount
1	403	Depreciation Expense	
2	404	Amortization of Limited-Term Electric Plant	
3	405	Amortization of Other Electric Plant	
4	406	Amortization of Electric Plant Acquisition Adjustments	
5	407	Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs	
6		Total Depreciation Exp. & Amortization	

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

Line No.	Account No.	Description	Amount
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 - Utility	
9	410.1	Feedback of Deferred State Income Taxes	
10	411.1	Feedback of Accumulated DFIT re: ABFUDC - Unit 1 Negative Amount Denotes Reduction.	
11	411.1	Feedback of Accumulated DFIT re: Overheads Capitalized - Unit 1	
12	411.1	Feedback of Accumulated DFIT - Other	
13	411.1	Feedback of Accumulated DFIT re: Other Schedule 'M' Adj.-Utility	----------
14		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	106	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	Miscellaneous 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-SERVICE INVESTMENT UNIT 1 (Cont'd)

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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 Progress	
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	======

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF NET CAPITALIZATION

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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		PREFERRED 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	
36	231.02	Notes Payable (Short-Term Debt)	
37	231.03	Unamortized Discount	
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	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)

Pg 18 of 18

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/.66)	
30	= Rate of Return (Pre-Tax)	

Kentucky Power Company

REQUEST

Please amend and provide revised exhibits LPM-13 and LPM-14 (KPSC 2-23, Attachment 1, pages 13-14) to remove line 16 & 17 from LPM-13.

RESPONSE

Revised exhibits LPM-13 and LPM-14 (KPSC 2-23, Attachment 1, pages 13-14) removing lines 16 & 17 from LPM-13, are attached.

WITNESS: Lila P Munsey

Kentucky Power Company
Pollution Control Environmental Facilities
New Environmental Costs Associated with
Allowance Inventory

Line No.	Description	Formula	KY Retail Rev Requirement	
(1)	(2)	(3)	(4)	
1	Estimated Monthly CSAPR SO2 Allowance Inventory	KIUC 1-20	$	425,976
2	Estimated Monthly CSAPR NOx Allowance Inventory	KIUC 1-20	$	2,053
3	Estimated Monthly CSAPR SO2 Consumption Expense	L11 / 12	$	517,667
4	Estimated Monthly CSAPR NOx Consumption Expense	L12 / 12	$	(54,167)
5	Net Monthly Expenses (Consumption less Gains)	L3 + L4	$	463,500
6	Cash Working Capital Allowance (in accordance with ES FORM 3.13)	L5 / 8	$	57,938
7	Total Rate Base	L1 + L2 + L6	$	485,967
8	Annual Weighted Average Cost of Capital	Exhibit LPM-3, L5, C8		10.69%
9	Return of Rate Base	L7 X L8	$	51,950
10	Estimated Monthly CSAPR SO2 Consumption Expense	Wohnhas testimony	$	6,212,000
11	Estimated Monthly CSAPR NOx Consumption Expense	Wohnhas testimony	$	(650,000)
12	Total Operating Expenses	L10 + L11	$	5,562,000
13	Total Revenue Requirement	L9 + L12	$	5,613,950
14	Annual Revenue Allocation Factor	Exhibit LPM-5, L15, C3		78.91%
15	Total KY Retail Revenue Requirement	L13 X L14	$	4,429,968
16	KY Jurisdiction 12-month Revenue	Exhibit LPM-5, L13, C3	$	569,593,245
17	Percent Change	L17 / L18		0.78%

Kentucky Power Company
Pollution Control Environmental Facilities
New Environmental Costs
Effect on Residential Customers

Line No.	Description	Formula	Annual Amount	Percent Increase
(1)	(2)	(3)	(5)	(6)
1	Annual Effect of New Environmental Pool Capacity Charges	Exhibit LPM-9, L14	$306,612	
2	KPCo's Share of Rockport	Exhibit LPM-12, L14	$480,780	
3	Total Environmental Cost	L1 + L2	$787,392	
4	KPCo's Average Retail Allocation for 12 months ended August 2011	Exhibit LPM-5, L.15, C3	78.91%	
5	Net Annual Impact on the Kentucky Retail Customers	L3 X L4	$621,331	0.10%
6	KY Retail Allowances	Exhibit LPM-13, L17, C4	$4,429,968	0.78%
7	KY Retail Revenue Requirement for Big Sandy Environmental Additions	Exhibit LPM-2, L15, C3	$162,993,233	28.62%
8	Total Environmental Projects in this Filing	L5 + L6 + L7	$168,044,532	29.50%
9	Billed Revenues for 12 months ended August 2011	Exhibit LPM-5, L13, C3	$569,593,245	
10	Percent Increase	L8 / L9	29.50%	
		Usage in kWh:	1,000	
11	Monthly Effect on a Residential Customers		$ 28.89	
12	Annualize		12	
13	Annual Effect on a Residential Customers	L11 X L12	$ 346.68	

Kentucky Power Company

REQUEST

Please refer to KPSC 2-23, Attachment 1, page 3, (LPM-3).

(a) Was the 5.6372 amount used for the state section 199 deduction calculation computed using a six percent or nine percent rate?

(b) If a nine percent rate was used, please confirm that the following amendments should be made:

(i) The amount of 5.6372 should be amended to 8.4728;

(ii) The gross revenue conversion factor should be amended to 1.5107;

(iii) The pre-tax weighted average cost of capital should be amended to 7.15;

(iv) The weight average cost of capital should be amended to 10.57%.

RESPONSE

(a) The 5.6372 amount used for the state section 199 deduction calculation was computed using a six percent rate instead of the nine percent rate that became effective for 2010.

(b) If a nine percent rate is used, the following amendments should be made:

(i) The amount of 5.6372 should be amended to 8.4728;

(ii) The gross revenue conversion factor of 1.5762 should be amended to 1.5492, which disagrees with the 1.5107 suggested by Staff;

(iii) The pre-tax weighted average cost of capital of 7.27% should be amended to 7.15;

(iv) The weight average cost of capital of 10.69% should be amended to 10.57%.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

If both Big Sandy 1 and 2 were retired at some time other than that set forth in the Company's Application, would the Company be subject to any penalties or other claims for damage under the contracts?

RESPONSE

The Big Sandy Plant currently has seven long term coal agreements. Of these agreements, four extend through the end of 2012, while three currently are expected to terminate at the end of 2013. If the Big Sandy Plant is required to cease operation prior to the termination of these contracts, KPCo may be required to pay liquidated damages for breach of contract on those coal supply agreements as well as any liquidated damages for lack of performance associated with transportation agreements.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Please provide an estimated net impact on the retail customers for the Big Sandy Unit 2 DFGD additions less any environmental retirements that would have to be made in connection with the project.

RESPONSE

The projected retirements associated with the DFGD project would produce an estimated reduction to Electric Plant In Service of $19.3 million and associated accumulated depreciation and ADIT of $10.2 and $3.2 million respectively. The net utility plant would be reduced by $5.9 million. This reduction and the estimated associated expense reductions of $13 million would reduce the impact on customers from 28.5% to 26.6% or approximately 2%. Using 1,000 kWh per month, the customer's monthly increase would decrease from $28.75 to $26.94 or $1.81. Using 1376 kWh per month (the 12-month ended August 2011 average residential usage), the customer's monthly increase would decrease from $38.63 to $36.20 or $2.43.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please identify any other AEP units that are subject to the Consent Decree, and whose owners are surplus members of the AEP Power pool, so that any environmental modifications made to the units may be flowed through Kentucky Power's ECR surcharge.

RESPONSE

There are 3 units whose future obligations under the NSR Consent Decree could impact KPCo's ECR Surcharge. They are Rockport Units 1 and 2 and Muskingum River Unit 5.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Please provide an update to Staff's 3-10 Data Request as of May 1, 2012.

RESPONSE

In regards to Kentucky Power's costs incurred for filing this case, an update to Staff's Data Request 3-10 for March 1, 2012 through April 30, 2012 is as follows:

Labor (actual):		
Kentucky Power ST Labor	$	109,166
Kentucky Power OT Labor	$	0
Service Corp. ST Labor	$	35,611
Service Corp. OT Labor	$	0
Subtotal Labor	$	144,777
Non-Labor (actual):		
Outside Services - Legal	$	102,801
- KPSC Consultants	$	13,780
- Professional	$	7,000
Materials and Supplies	$	1,991
Advertising	$	707
Subtotal Non-Labor	$	126,279
Total	$	271,056

WITNESS: Ranie K Wohnhas