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February 20, 2014

RECEIVED

FEB 20 2014

PUBLIC SERVICE COMMISSION

HAND DELIVERED

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Case No. 2013-00475

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of the Company's responses to Staff's February 4, 2014 data requests, and the Company's public responses to Sierra Club's February 5, 2014 data requests.

Also enclosed is the Company's motion for confidential treatment and attached confidential portions of the Company's responses to Sierra Club data requests 1-2, 1-3, 1-14, 1-21, and 1-24.

Copies of the responses and the motion are being served by overnight delivery today on the persons listed below.

Very truly yours,

Mark R. Overstreet

MRO
cc: Michael L. Kurtz
Kristin Henry
Shannon Fisk
Joe F. Childers

RECEIVED

FEB 2 0 2014

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

INTEGRATED RESOURCE PLANNING REPORT OF)
KENTUCKY POWER COMPANY TO THE) CASE NO. 2013-00475
KENTUCKY PUBLIC SERVICE COMMISSION)

KENTUCKY POWER COMPANY RESPONSES TO BEVERLEY MAY, ALEXANDER DESHA, AND SIERRA CLUB INITIAL SET OF DATA REQUESTS

February 20, 2014

VERIFICATION

The undersigned, Will K. Castle, being duly sworn, deposes and says he is the Director Resource and DSM Planning 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

Will K Castle

Will K. Castle

STATE OF OHIO)
) Case No. 2013-00475
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State by Will K. Castle, this the 6th day of February 2014.

Charmaine S. Hamilton

Notary Public

My Commission Expires: ____________

NOTARIAL SEAL STATE OF OHIO

CHARMAINE S. HAMILTON
Notary Public, State of Ohio
My Commission Expires 05-14-~~2014~~ 2017
CSH

VERIFICATION

The undersigned, John F. Torpey, being duly sworn, deposes and says he is the Director Integrated Resource Planning 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 F Torpey

John F. Torpey

STATE OF OHIO)
) Case No. 2013-00475
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John F. Torpey, this the 6th day of February 2014.

Josephine Coner

Notary Public

NOTARIAL SEAL STATE OF OHIO

JOSEPHINE CONER
Notary Public, State of Ohio
My Commission Expires 09-20-16

My Commission Expires: 09-20-2016

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. 2013-00475
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 17th day of February 2014.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Produce all discovery responses to any other party in this proceeding.

RESPONSE

As required by the Commission's February 5, 2014 order in this case, Kentucky Power is providing copies of all documents filed in this case.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Produce a non-redacted, color, electronic version of the IRP filing, including all exhibits and appendices.

RESPONSE

Please see SC 1-2 Attachments 1 - 4 on the enclosed CD. Confidential treatment is being sought for Attachment 4.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Produce any workpaper, source document, and, in machine readable format with formulas intact, input and output files, used in or developed in the evaluation of supply-side resources for the IRP.

RESPONSE

Please see enclosed CD for SC 1-3 Confidential Attachment 1 and SC 1-3 Attachment 2. Confidential treatment is being sought for the following files within SC 1-3 Confidential Attachment 1:

KPCO 2-Pager Summary Base Optimized Plan MAB.xls
KPCO 2-Pager Summary High CO2 Optimized Plan MAB.xls
KPCO 2-Pager Summary High Optimized Plan MAB.xls
KPCO 2-Pager Summary Low Optimized Plan MAB.xls
KPCO 2-Pager Summary No CO2 Optimized Plan MAB.xls
KPCO 2-Pager Summary Preferred Plan MAB.xls

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Produce any workpaper, source document, and, in machine readable format with formulas intact, input and output files, used in or developed in the evaluation of demand-side resources for the IRP.

RESPONSE

Please see the Company's response to Sierra Club 1-3.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Produce in machine readable format with formulas intact the input and output files for each sensitivity analysis that you considered as part of this resource planning process.

RESPONSE

Please see the Company's response to Sierra Club 1-3.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 2, footnote 6 of the IRP (Volume A).

a. Produce the Power Coordination Agreement

b. Explain the off-system sales allocation methodology referenced therein

c. If the Power Coordination Agreement is not approved by FERC, state whether KPC's resource plan would be impacted.

   i. If so, explain how
   ii. If not, explain why not

RESPONSE

a. Please refer to SC 1-6 Attachment 1.

b. Off System Transactions and their allocations are as described in Article 7.5 and Service Schedules B and C. Most activity will be directly assigned to individual operating companies, while certain transactions will be allocated based on the respective surplus of each supplying company. Trading margins will be allocated based on total proprietary capital as stated in each company's FERC Form 1.

c. N/A. The Power Coordination Agreement was approved by FERC in an Order dated December 23, 2013 in Docket No. ER13-234-000.

WITNESS: John F Torpey

Sheet No. 1

RATE SCHEDULE No. 300

POWER COORDINATION AGREEMENT

among

APPALACHIAN POWER COMPANY,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY POWER COMPANY

and

AMERICAN ELECTRIC POWER SERVICE CORPORATION

as Agent

Tariff Submitter: **Appalachian Power Company**
FERC Program Name: **FERC FPA Electric Tariff**
Tariff Title: **APCo Rate Schedules and Service Agreements Tariffs**
Tariff Proposed Effective Date: **01/01/2014**
Tariff Record Title: **Power Coordination Agreement**
Option Code: **A**
Record Content Description: **Rate Schedule No. 300**

POWER COORDINATION AGREEMENT

THIS AGREEMENT is made and entered into as of this 1st day of January, 2014, by and among Appalachian Power Company ("APCo"), Indiana Michigan Power Company ("I&M"), Kentucky Power Company ("KPCo") and American Electric Power Service Corporation ("AEPSC") as agent ("Agent") to APCo, I&M and KPCo.

RECITALS:

WHEREAS, APCo, I&M and KPCo (collectively the "Operating Companies" or individually "Operating Company") own and operate electric generation, transmission and distribution facilities with which they are engaged in the business of generating, transmitting and selling electric power to the general public and to other electric utilities;

WHEREAS, the Operating Companies' electric facilities are now and have been for many years interconnected through their respective transmission facilities and transmission facilities of third parties at a number of points;

WHEREAS, APCo, I&M and KPCo provide power to serve retail and wholesale customers in Indiana, Kentucky, Michigan, Tennessee, Virginia and West Virginia;

WHEREAS, APCo, I&M and KPCo believe that they can continue to achieve efficiencies and economic benefits through (a) participation in the organized power markets of a regional transmission organization and (b) allocation of off-system sales and purchases with other parties on bases that fairly assign or allocate the costs and benefits of these transactions;

WHEREAS, the achievement of the foregoing will be facilitated by the performance of certain services by an Agent;

WHEREAS, AEPSC is the service company affiliate of APCo, I&M and KPCo and as such performs a variety of services on their behalf in accordance with applicable rules and regulations of the Federal Energy Regulatory Commission ("Commission"); and

WHEREAS, AEPSC is willing to serve as Agent to APCo, I&M and KPCo under this Agreement.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein set forth, the Parties mutually agree as follows:

ARTICLE I
DEFINITIONS

1.1 **Agreement** means this Power Coordination Agreement among APCo, I&M, KPCo and Agent, including all Service Schedules and attachments hereto.

1.2 **Capacity Auction** means auctions implemented pursuant to a Capacity Market, and may include, but is not necessarily limited to, the Base Residual Auction and other incremental auctions conducted in accordance with the PJM Interconnection, LLC ("PJM") Reliability Pricing Model market rules.

1.3 **Capacity Market** means any market of an applicable regional transmission organization under which the Operating Companies satisfy their capacity obligations as load serving entities, which would include, for example, the PJM capacity market as described in the PJM Reliability Assurance Agreement ("RAA") and Attachment DD of the PJM Open Access Transmission Tariff ("PJM OATT").

1.4 **Dedicated Wholesale Customer** means a wholesale customer whose load is served by an Operating Company that has undertaken, by contract, an obligation to serve that customer's partial or full requirements load and to acquire power supply resources and other resources necessary to meet those requirements.

1.5 Generation Hedge Transactions means Off-System Transactions entered into for the purpose of hedging the output of the generation assets of one or more of the Operating Companies.

1.6 Industry Standards means all applicable national and regional electric reliability council and regional transmission organization principles, guides, criteria, standards and practices.

1.7 Internal Load means all sales of power, plus associated line losses, by an Operating Company to its Retail Customers and Dedicated Wholesale Customers. As distinguished from Off-System Sales, Internal Load is principally characterized by the Operating Company assuming the load obligation as its own power commitment.

1.8 Off-System Sales means all wholesale power sales by an Operating Company other than sales to the Retail Customers and Dedicated Wholesale Customers that comprise the Operating Company's Internal Load. Sales of wholesale power by an Operating Company to another Operating Company are not governed by this Agreement, and will not be deemed Off-System Sales under this Agreement.

1.9 Off-System Purchases means wholesale power purchases by an Operating Company or Operating Companies for any of the following reasons: (a) to reduce power supply costs, (b) to serve load requirements, (c) to provide reliability of supply, (d) to satisfy state specific requirements or goals or (e) to engage in Off-System Sales. Purchases of wholesale power by an Operating Company from another Operating Company are not governed by this Agreement, and will not be deemed Off-System Purchases under this Agreement.

1.10 Off-System Transactions means Off-System Sales, Off-System Purchases and any other types of power-related wholesale transactions, whether physical or financial, on behalf of an Operating Company or Operating Companies, excluding sales to Internal Load customers.

1.11 Operating Committee means the administrative body established pursuant to Article VI for the purposes specified within this Agreement.

1.12 Party means each of APCo, I&M, KPCo and Agent, individually, and **Parties** means APCo, I&M, KPCo and Agent, collectively.

1.13 Retail Customer means a retail power customer on whose behalf an Operating Company has undertaken an obligation to obtain power supply resources in order to supply electricity to reliably meet the electric needs of that customer.

1.14 Service Schedules means the Service Schedules attached to this Agreement, as they may be amended from time to time, and those that later may be agreed to by the Parties and made part of a modified Agreement.

1.15 Spot Market means the day ahead, real time (balancing) or similar short-term energy market(s) operated by the applicable regional transmission organization(s), typically characterized by energy that is selected and delivered on an hourly, or more frequent, basis during that same day or the next calendar day.

1.16 System Emergency means a condition which, if not promptly corrected, threatens to cause imminent harm to persons or property, including the equipment of a Party or a Third Party, or threatens the reliability of electric service provided by an Operating Company to Retail Customers or Dedicated Wholesale Customers.

1.17 Third Party or Third Parties means any entity or entities that are not a Party or Parties.

1.18 Trading Transactions means Off-System Transactions that are not Generation Hedge Transactions or otherwise sourced or hedged from, dedicated to, or associated with the generation assets or Internal Load of the Operating Companies.

ARTICLE II
TERM OF AGREEMENT

2.1 Term and Withdrawal. Subject to Commission approval or acceptance for filing, this Agreement shall take effect on January 1, 2014, or such other date permitted by the Commission, and shall continue in full force and effect until (a) terminated by mutual agreement or (b) upon no less than twelve (12) months' written notice by one Party to each of the other Parties, after which time the notifying Party will be withdrawn from the Agreement and the Agreement will continue in full force and effect for the remaining Parties except for such modifications necessary to remove the withdrawn Party.

ARTICLE III
[INTENTIONALLY OMITTED]

ARTICLE IV
SCOPE AND RELATIONSHIP TO OTHER AGREEMENTS AND SERVICES

4.1 Scope. This Agreement is not intended to preclude the Parties from entering into other arrangements between or among themselves or with Third Parties. This Agreement is intended to operate in addition to, not in lieu of, power market transactions and settlements that occur between each Operating Company, or the Operating Companies collectively, and any applicable regional transmission organizations.

4.2 Transmission. This Agreement is intended to apply to the coordination of the power supply resources of, and loads served by, the Operating Companies. It is not intended to apply to the coordination of transmission facilities owned or operated by the Operating Companies.

ARTICLE V
AGENT

5.1 Agent. The Agent will perform the activities and duties specified by this Agreement and any other activities or duties pertaining to this Agreement that may be requested from time to time by one or more Operating Companies, subject to the receipt of any necessary regulatory approvals. The Operating Companies delegate to AEPSC, as the Agent, and AEPSC hereby accepts responsibility and authority for the duties specified in this Agreement and shall perform each of those duties under the direction of the Operating Companies. With the prior written consent of the Operating Companies, AEPSC may delegate all or a part of its responsibilities under this Agreement to another entity.

ARTICLE VI
COMPOSITION AND DUTIES OF
THE OPERATING COMMITTEE

6.1 Operating Committee. By written notice to the other Parties, each Party shall name one representative ("Representative") to act for it in matters pertaining to this Agreement and its implementation. A Party may change its Representative at any time by written notice to the other Parties. The Representatives of the respective Parties shall comprise the Operating Committee. The Agent's Representative shall act as the chairman of the Operating Committee ("Chairman"). All decisions of the Operating Committee shall be by a simple majority vote of the Representatives. There shall be only four voting representatives on the Operating Committee. No Party may delegate its vote to another entity.

6.2 Meeting Dates. The Operating Committee shall hold meetings at such times, means, and places as the members shall determine. Minutes of each Operating Committee meeting shall be prepared and maintained.

6.3 Duties. The Operating Committee shall have the duties listed below:

(a) reviewing and providing direction concerning the equitable sharing of costs and benefits under this Agreement among the Operating Companies;

(b) administering this Agreement and proposing amendments hereto, including such amendments that are proposed in response to a change in regulatory requirements applicable to one or more of the Operating Companies or changes concerning an applicable regional transmission organization, provided that any amendments will be subject to Section 13.2; and

(c) reviewing and, if necessary, proposing changes to the duties and responsibilities of the Agent, subject to Section 5.1.

In the event that an action of the Operating Committee results in a change to the settlement process(es) among the Operating Companies, such modified settlement will normally occur on a prospective basis only, however, this may include past billing periods back to the beginning of the first full billing month preceding the date of action of the Operating Committee. Such modifications will be subject to the terms of Article IX as applicable.

ARTICLE VII
OPERATING COMPANY PLANNING AND OPERATIONS

7.1 Operating Company and System Planning. Each Operating Company will be individually responsible for its own capacity planning. Consistent with the requirements of PJM or the applicable regional transmission or reliability organization, each Operating Company will be responsible for maintaining an adequate level of power supply resources to meet its own

Internal Load requirements for capacity and energy, including any required reserve margins, and shall bear all of the resulting costs. The Agent shall assess the adequacy of the power supply resources of the Operating Companies and make recommendations to each Operating Company regarding (1) the need for additional power supply resources and (2) whether each Operating Company has power supply resources in excess of its needs (short-term or long-term) that could be made available to the other Operating Companies or Third Parties either through separate contracts or through the power markets of the applicable regional transmission organization. The actual addition or disposition of power supply resources will be conditioned on compliance with all applicable state and other regulatory requirements and requirements of the applicable regional transmission organization.

7.2 Generation Resource Outage Planning. The Agent, on behalf of the Operating Companies, will coordinate the scheduling of planned generation resource outages in order to support reliability and manage costs.

7.3 Generation Resource Dispatch. The generation resources of each of the Operating Companies will be individually dispatched by the Agent in accordance with the direction of the applicable regional transmission organization.

7.4 Regional Transmission Organization Transactions. The Agent will administer the participation of the Operating Companies in the power markets of the applicable regional transmission organization. Each Operating Company shall be individually responsible for charges it incurs and credits it receives due to its participation in the power markets of a regional transmission organization. Such costs and revenues will be assigned or allocated directly by the applicable regional transmission organization or its agent where practical. The Operating Companies may collectively participate from time to time in specific markets of the regional transmission organization or to meet certain regional transmission or reliability organization requirements, in which case the allocation of resulting revenues and/or costs, if any, will be performed as specified herein. The election of whether each Operating Company's load and generation resources will participate in the Capacity Market of PJM through the Reliability Pricing Model auctions or through the Fixed Resource Requirement alternative, either collectively or individually, for any planning year is not governed by this Agreement.

7.5 **Off System Transactions**. The Agent will engage in Off-System Transactions on behalf of or at the direction of the Operating Companies and will assign or allocate the costs and revenues of Off-System Transactions to the Operating Companies in the manner specified below.

7.5.1 **Capacity Purchases and Sales with Third Parties**. Except as described in Section 7.5.2 related to the PJM Capacity Auctions: (1) Off-System Transactions of capacity undertaken for an individual Operating Company will be directly assigned to that Operating Company; (2) Off-System Purchases of capacity undertaken for more than one Operating Company will be allocated among those Operating Companies ratably in proportion to the total capacity needed by each Operating Company minus each Operating Company's total capacity resources; and (3) Off-System Sales of capacity undertaken for more than one Operating Company will be allocated among those Operating Companies ratably in proportion to the total capacity resources of each Operating Company minus the total capacity obligation of each Operating Company (including any holdback required by the applicable regional transmission organization).

7.5.2 **Capacity Purchases and Sales in the PJM Capacity Auctions And Related Issues**. When an Operating Company participates individually in the Reliability Pricing Model or the Fixed Resource Requirement alternative, Off-System Transactions of capacity related to a PJM Capacity Auction will be directly assigned to the specific Operating Company based on the results of such auctions.

When two or more Operating Companies collectively participate in the Fixed Resource Requirement alternative, any Off-System Transactions of capacity related to a PJM Capacity Auction will be allocated to each participating Operating Company ratably in proportion to the total capacity resources of each Operating Company minus the total capacity obligation of each Operating Company (including any holdback required by PJM) for the applicable planning year(s), and Service Schedule A will apply to delivery year and post-delivery year obligations of the participating Operating Companies associated with the Fixed Resource Requirement alternative.

7.5.3 Directly Assigned Energy Purchases and Sales with Third Parties. Off-System Transactions of energy will be directly assigned to the applicable Operating Company. Costs and revenues associated with each Operating Company's Off-System Sales of energy and Internal Load energy purchases from the applicable regional transmission organization in the Spot Market, including the purchase of any energy deficits or sales of any energy surpluses, will be directly assigned to that Operating Company.

7.5.4 Generation Hedge Transactions and Trading Transactions. Revenues and costs associated with Generation Hedge Transactions, including revenues and costs associated with the settlement of Generation Hedge Transactions in the Spot Market or other markets of the applicable regional transmission organization, will be allocated among the Operating Companies by the Agent as specified under Service Schedule B.

Revenues and costs associated with Trading Transactions, including revenues and costs associated with the settlement of Trading Transactions in the Spot Market or other markets of the applicable regional transmission organization, will be allocated among the Operating Companies by the Agent as specified under Service Schedule C.

7.6 Emergency Response. In the event of a System Emergency, no adverse distinction shall be made between the customers of any of the Operating Companies. Each Operating Company shall, under the direction of the applicable regional transmission organization, make its power supply resources available in response to a System Emergency. Notwithstanding the foregoing, it is understood that transmission constraints or other factors may limit the ability of an Operating Company to respond to a System Emergency.

ARTICLE VIII
ASSIGNMENT OF COSTS AND BENEFITS OF COORDINATED OPERATIONS

8.1 Service Schedules. The costs and revenues associated with coordinated operations as described in Article VII shall be distributed among the Operating Companies in the manner provided in the Service Schedules utilizing the billing procedures described in Article IX. It is understood and agreed that all such Service Schedules are intended to establish an equitable sharing of costs and/or benefits among the Operating Companies, and that circumstances may, from time to time, require a reassessment of the relative costs and benefits of this Agreement, or of the methods used to apportion costs and benefits under the Service Schedules. Upon a proposal of the Operating Committee, any of the Service Schedules may be amended as of any date agreed to by the Operating Committee by majority vote, subject to Section 13.2.

ARTICLE IX
BILLING PROCEDURES

9.1 Records. The Agent shall maintain such records as may be necessary to determine the assignment of costs and revenues of coordinated operations pursuant to this Agreement. Such records shall be made available to the Parties upon request for a period not to exceed three (3) years.

9.2 Monthly Net Billing Statements. As promptly as practicable after the end of each calendar month, the Agent shall prepare a statement setting forth the monthly summary of costs and revenues allocated or assigned to the Operating Companies in sufficient detail as may be needed for settlements under the provisions of this Agreement. As required, the Agent may provide such statements on an estimated basis and then adjust those statements for actual results.

9.3 Billings and Payments. The Agent shall be responsible for all billing between the Operating Companies and other entities with which they engage in Off-System Transactions pursuant to this Agreement. Payments among the Operating Companies, if any, shall be made by remittance of the net amount billed or by making appropriate accounting entries on the books of the Parties. The entire amount shall be paid when due.

9.4 Taxes. Should any federal, state, or local tax, surcharge or similar assessment, in addition to those that may now exist, be levied upon the electric capacity, energy, or services to be provided in connection with this Agreement, or upon the provider of service as measured by the electric capacity, energy, or services, or the revenue there from, such additional amount shall be included in the net billing described in Section 9.3.

9.6 Undelivered and Unpaid Monthly Billing Statements. Within one (1) year from the date on which a billing statement should have been delivered, if a Party's records reveal that the bill was not delivered, then the Agent shall deliver to the appropriate Party a bill within one (1) month of this determination. Any amounts collected or reimbursed due to such delay shall not include interest.

9.7 <u>**Billing Errors and Disputes**</u>. If a Party discovers a billing error pertaining to a prior billing for reasons including, but not limited to, missing or erroneous data or calculations, including those caused by meter, computer or human error, a correction adjustment will be calculated through the second full month preceding discovery of the error. The Parties shall have the right to dispute the accuracy of any bill or payment for a period not to exceed two months from the date on which the bill or, if applicable, the corrected bill was initially delivered. Following this two-month period, the right to dispute a bill is permanently waived for any and all reasons including but not limited to, (a) errors, (b) omissions, (c) Agent's actions, and (d) the Operating Committee's decisions, Agreement interpretations and direction in the administration of the Agreement. Any amounts collected or reimbursed due to such disputes shall not include interest.

ARTICLE X
FORCE MAJEURE

10.1 <u>**Events Excusing Performance**</u>. No Party shall be liable to another Party for or on account of any loss, damage, injury, or expense resulting from or arising out of a delay or failure to perform, either in whole or in part, any of the agreements, covenants, or obligations made by or imposed upon the Parties by this Agreement, by reason of or through strike, work stoppage of labor, failure of contractors or suppliers of materials (including fuel, consumables or other goods and services), failure of equipment, environmental restrictions, riot, fire, flood, ice, invasion, civil war, commotion, insurrection, military or usurped power, order of any court or regulatory agency granted in any *bona fide* legal proceedings or action, or of any civil or military authority either *de facto* or *de jure*, explosion, Act of God or the public enemies, or any other cause reasonably beyond its control and not attributable to its neglect. A Party experiencing such a delay or failure to perform shall use due diligence to remove the cause or causes thereof; however, no Party shall be required to add to, modify or upgrade any facilities, or to settle a strike or labor dispute except when, according to its own best judgment, such action is advisable.

ARTICLE XI
DELIVERY POINTS

11.1 <u>**Delivery Points**</u>. All electric energy delivered under this Agreement shall be of the character commonly known as three-phase sixty-cycle energy, and shall be delivered at the various points where the transmission systems of the Operating Companies are interconnected, either directly or through transmission facilities of third parties, at the nominal unregulated voltage designated for such points, and at such other points and voltages as may be determined and agreed upon by the Operating Companies.

ARTICLE XII
GENERAL

12.1 <u>**Adherence to Industry Standards**</u>. The Parties agree to make their best efforts to conform to Industry Standards as they affect the implementation of and conduct pertaining to this Agreement.

12.2 <u>**No Third Party Beneficiaries**</u>. This Agreement does not create rights of any character whatsoever in favor of any person, corporation, association, entity or power supplier, other than the Parties, and the obligations herein assumed by the Parties are solely for the use and benefit of the Parties. Nothing in this Agreement shall be construed as permitting or vesting, or attempting to permit or vest, in any person, corporation, association, entity or power supplier, other than the Parties, any rights hereunder or in any of the resources or facilities owned or controlled by the Parties or the use thereof.

12.3 Waivers. Any waiver at any time by a Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this Agreement, shall not be deemed a waiver of such right.

12.4 Successors and Assigns. This Agreement shall inure to the benefit of and be binding upon the Parties only, and their respective successors and assigns, and shall not be assignable by any Party without the written consent of the other Parties except to a successor in the operation of its properties by reason of a reorganization to comply with state or federal restructuring requirements, or a merger, consolidation, sale or foreclosure whereby substantially all such properties are acquired by or merged with those of such a successor.

12.5 Liability and Indemnification. SUBJECT TO ANY APPLICABLE STATE OR FEDERAL LAW THAT MAY SPECIFICALLY RESTRICT LIMITATIONS ON LIABILITY, EACH PARTY (AN "INDEMNIFYING PARTY") SHALL RELEASE, INDEMNIFY, AND HOLD HARMLESS THE OTHER PARTIES (EACH AN "INDEMNIFIED PARTY"), THEIR DIRECTORS, OFFICERS AND EMPLOYEES FROM AND AGAINST ANY AND ALL LIABILITY FOR LOSS, DAMAGE OR EXPENSE (1) ALLEGED TO ARISE FROM, OR BE INCIDENTAL TO, INJURY TO PERSONS AND/OR DAMAGE TO PROPERTY IN CONNECTION WITH THE INDEMNIFYING PARTY'S FACILITIES OR THE PRODUCTION OR TRANSMISSION OF ELECTRIC ENERGY BY OR THROUGH THE INDEMNIFYING PARTY'S FACILITIES OR (2) RELATED TO PERFORMANCE OR NON-

PERFORMANCE OF THIS AGREEMENT OR (3) RELATED TO ANY NEGLIGENCE ARISING UNDER THIS AGREEMENT. IN NO EVENT SHALL ANY PARTY BE LIABLE TO ANOTHER PARTY FOR ANY INDIRECT, SPECIAL, INCIDENTAL, OR CONSEQUENTIAL DAMAGES WITH RESPECT TO ANY CLAIM ARISING OUT OF THIS AGREEMENT.

12.6 __Headings.__ The descriptive headings of the Articles, Sections and Service Schedules of this Agreement are used for convenience only, and shall not modify or restrict any of the terms and provisions thereof.

12.7 __Notice.__ Any notice or demand for performance required or permitted under any of the provisions of this Agreement shall be deemed to have been given on the date such notice, in writing, is deposited in the U.S. mail, postage prepaid, certified or registered mail, addressed to the Parties at their principal place of business at 1 Riverside Plaza, Columbus, Ohio 43215, or in such other form or to such other address as the Parties may stipulate.

12.8 __Interpretation.__ In this Agreement: (a) unless otherwise specified, references to any Article or Section are references to such Article or Section of this Agreement; (b) the singular includes the plural and the plural includes the singular; (c) unless otherwise specified, each reference to a requirement of any governmental entity or regional transmission organization includes all provisions amending, modifying, supplementing or replacing such governmental entity or regional transmission organization from time to time; (d) the words "including," "includes" and "include" shall be deemed to be followed by the words "without limitation"; (e) unless otherwise specified, each reference to any tariff or agreement includes all amendments, modifications, supplements, and restatements made to such tariff or agreement from time to time which are not prohibited by this Agreement; (f) the descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict the terms and provisions thereof; and (g) "herein," "hereof," "hereto" and "hereunder" and similar terms refer to this Agreement as a whole.

ARTICLE XIII
REGULATORY APPROVAL

13.1 <u>**Regulatory Authorization.**</u> This Agreement is subject to and conditioned upon its approval or acceptance for filing without material condition or modification by the Commission. In the event that this Agreement is not so approved or accepted for filing in its entirety or without conditions or modifications unacceptable to any Party, or the Commission subsequently modifies this Agreement upon complaint or upon its own initiative (as provided for in Section 13.2), any Party may, irrespective of the notice provisions in Section 2.1, withdraw from this Agreement by giving thirty (30) days' advance written notice to the other Parties.

13.2 <u>**Changes.**</u> It is contemplated by the Parties that it may be appropriate from time to time to change, amend, modify, or supplement this Agreement, including the Service Schedules and any other attachments that may be made a part of this Agreement, to reflect changes in operating practices or costs of operations or for other reasons. Any such changes to this Agreement shall be in writing executed by the Parties and subject to approval or acceptance for filing by the Commission.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

APPALACHIAN POWER COMPANY

By: Charles Patton

Title: President & COO

INDIANA MICHIGAN POWER COMPANY

By: ______________________

Title: ______________________

KENTUCKY POWER COMPANY

By: ______________________

Title: ______________________

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: ______________________

Title: ______________________

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

APPALACHIAN POWER COMPANY

By: ______________________________

Title: ______________________________

INDIANA MICHIGAN POWER COMPANY

By: Paul Chodak

Title: President & Chief Operating Officer

KENTUCKY POWER COMPANY

By: ______________________________

Title: ______________________________

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: ______________________________

Title: ______________________________

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

APPALACHIAN POWER COMPANY

By: ______________________________

Title: ______________________________

INDIANA MICHIGAN POWER COMPANY

By: ______________________________

Title: ______________________________

KENTUCKY POWER COMPANY

By: Gregory G. Pauley

Title: President + COO

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: ______________________________

Title: ______________________________

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

APPALACHIAN POWER COMPANY

By: ______________________________

Title: ______________________________

INDIANA MICHIGAN POWER COMPANY

By: ______________________________

Title: ______________________________

KENTUCKY POWER COMPANY

By: ______________________________

Title: ______________________________

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: Richard E. Munczinski

Title: SVP - Regulatory Services

SERVICE SCHEDULE A
COLLECTIVE PARTICIPATION IN THE
FIXED RESOURCE REQUIREMENT ALTERNATIVE

A1– Duration. This Service Schedule A shall become effective and binding when the Agreement of which it is a part becomes effective, and shall continue in full force and effect throughout the duration of the Agreement unless terminated or suspended.

A2 – Availability of Service. This Service Schedule A governs the administration and settlement of capacity during such times that multiple Operating Companies are participating, on a collective basis, in the Fixed Resource Requirement alternative.

A3 – Delivery Year and Post-Delivery Year Settlement. During a given PJM planning year (i.e., the delivery year), the Agent will manage the capacity resources needed to meet the combined Operating Companies' capacity obligations and commitments to PJM.

If capacity resource performance charges are assessed by PJM for a given delivery year, the total net charge will be allocated among the Operating Companies ratably in proportion to each Operating Company's contribution to the total charge, taking into account the effect of collective participation of the Operating Companies in the Fixed Resource Requirement alternative. Each Operating Company's contribution to the total net charge will be determined by the Agent by computing a total MW position for each Operating Company by subtracting its total capacity obligation in MWs from its total capacity resources in MWs. This result will be further adjusted by adding or subtracting as applicable the net total MWs of actual under-performance or over-performance of each Operating Company's capacity resources during the delivery year as computed by PJM. Any Operating Company with a resulting net short MW position, meaning that its capacity obligation MWs are greater than its capacity resource MWs including any MWs of over-performance or under-performance, will be allocated a share of the total net performance charge from PJM based on the Operating Company's net short MW position. Any performance charge not allocated as set forth above will be directly assigned to the Operating Company that caused the performance charge.

SERVICE SCHEDULE B
GENERATION HEDGE TRANSACTIONS

B1 – Duration. This Service Schedule B shall become effective and binding when the Agreement of which it is a part becomes effective, and shall continue in full force and effect throughout the duration of the Agreement unless terminated or suspended.

B2 – Service. This Service Schedule B governs energy-related Off-System Transactions made pursuant to Section 7.5.4 of the Agreement that are associated with Generation Hedge Transactions as defined in Section 1.3. The total monthly net costs and revenues from the settlement of Generation Hedge Transactions will be allocated among the Operating Companies ratably in proportion to the total of each Operating Company's surplus MWhs for the month, as determined by the Agent. Surplus MWhs will be computed as the total of all MWs in hours in which an Operating Company's MW output of its generation assets and energy purchases exceeded that Operating Company's Internal Load.

If the above allocation would result in any Operating Company being allocated revenues or costs associated with more than one hundred and fifteen percent (115%) of its monthly surplus MWhs as computed above, such excess(es) above that amount will be allocated to all of the Operating Companies ratably in proportion to the sum of each Operating Company's hourly MW output of its generation assets for the month.

SERVICE SCHEDULE C
TRADING TRANSACTIONS

C1 – Duration. This Service Schedule C shall become effective and binding when the Agreement of which it is a part becomes effective, and shall continue in full force and effect throughout the duration of the Agreement unless terminated or suspended.

C2 – Service. This Service Schedule C governs the financial allocation and settlement of Off-System Transactions made pursuant to Section 7.5.4 of the Agreement that are associated with Trading Transactions as defined in Section 1.16. All Trading Transactions settled for a given month will be allocated among the Operating Companies ratably in proportion to each Operating Company's total common shareholder equity balance. The total common shareholder equity balance for each Operating Company as of the end of the previous calendar year will be as stated in the FERC Form 1, currently page 112 (Total Proprietary Capital). These balances will then be applied to allocate settled Trading Transactions among the Operating Companies during the subsequent twelve-month period beginning June 1 and ending May 31.

Kentucky Power Company

REQUEST

Refer to page 5 of the IRP (Volume A). With regards to the agreement to purchase 393MW of capacity from the Rockport plant

a. Produce the unit power agreement with AEP Generating Company

b. State whether KPC has the option to terminate the unit power agreement before December 7, 2022.

   i. If so, identify any penalties or costs that could result from such early termination.

c. Identify and explain the bases for assuming that the unit power agreement would be extended beyond the end of the planning period.

d. Explain how costs of environmental capital expenditures to the Rockport Plant are allocated to KPC

e. State whether you modeled or evaluated any scenarios in which KPC ends the purchase of 393MW of capacity from the Rockport plant before 2028

   i. If so, produce and explain the results of such scenario
   ii. If not, explain why not

RESPONSE

a. Please refer to SC 1-7 Attachment 1.

b. No.

c. For this 2013 IRP, assumptions regarding the continuation of the unit power agreement will not have an impact on any near term actions. A decision on whether the unit power agreement is extended beyond 2022 will be addressed as the expiration date of the agreement nears.

d. The allocation of capital expenditures is described in the rate design section of the unit power agreement.

e. There were no scenarios modeled that included the termination of the capacity from the Rockport Unit Power assessment. Please see the response to part (c) above.

WITNESS: John F Torpey

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. I 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. 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 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 less 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 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 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:

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

Where:

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

and

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

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

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 16

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. BS1	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 -	
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	118	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 Incoma Taxes - Accelerated Amortization Property	
34	282	+Accumulated Deferred Income Taxes - Dther 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	188.50	-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	188	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)	

Kentucky Power Company

REQUEST

Refer to page 7 of the IRP (Volume A). With regards to the load forecast:

a. State whether the experience for the summer season of 2013 is consistent or inconsistent with the load forecast. Explain your answer.

b. Identify and explain each of the "other relevant changes" not reflected in the load forecast.

RESPONSE

a. The summer 2013 experience is consistent with the load forecast. The Company forecasted a summer peak of 1,143 MW and the actual summer peak was 1,138 MW or a difference of 0.4%.

b. There were no significant "other relevant changes" other than the further deterioration of the coal mining sector.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to "Figure 9: Solar Dynamic Effects" on page 97 of the IRP (Volume A):

a. Please describe and quantify the components of the "PJM Value of Solar."

b. Please provide the "full retail net metering rate."

c. Produce any workpapers, source documents, and, in machine readable format with formulas intact, input and output files, used in or developed as part of the analysis of distributed generation reflected in Figure 9.

RESPONSE

a. The PJM value of solar refers to the capacity and energy value of solar within PJM.

b. The beginning (2013) full retail net metering rate for this analysis was $0.085/kWh.

c. Please see SC 1-9 Attachment 1 on the enclosed CD.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 98 of the IRP (Volume A). Identify and produce any analysis or study regarding the statement that utility-owned (or purchased) solar generation is expected to become economic around 2020.

RESPONSE

Please see the Company's response to SC 1-9(c).

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Please state whether the Company evaluated increasing the projected load impacts of existing EE programs during the planning period. If yes, please explain how the Company conducted such evaluation. If no, please explain why not.

RESPONSE

The Company did not specifically evaluate an expansion of current programs. The Company does not have the hourly information necessary to precisely model an expansion of current programs. Expanding current programs may be done as an alternative to, or in conjunction with initiating new programs.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Please provide the socket saturation rate for CFLs in KPC's service territory.

RESPONSE

The Company does not have an estimate of the socket saturation rate for CFLs in its service territory.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Referring to page 85 of the IRP (Volume A), please describe the process the Collaborative undertook to decide which DSM programs were to be screened for potential implementation in Kentucky Power's service territory.

RESPONSE

New DSM programs as well as proposed changes to existing DSM programs are presented to the DSM Collaborative for review and comment before filing with the KPSC. DSM information is normally reviewed at scheduled meetings with the DSM Collaborative. Historically, the DSM Collaborative has had four scheduled on-site meetings per year.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Referring to page 87 of the IRP (Volume A), please provide all assessments of EE/DR achievable potential conducted by or for the Company.

RESPONSE

No assessment of EE potential was performed by or for the Company. The Company performed an assessment of DR potential included in SC 1-14 Confidential Attachment 1. Because the file contains data that would not be useful in printed format, the Company is providing it only in electronic format.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Referring to page 89 of the IRP (Volume A), please provide the data underlying "Figure 4: Relationship of Incentive Percentage to Participation."

RESPONSE

Please see SC 1-15 Attachment 1. Because the file contains data that would not be useful in printed format, the Company is providing it only in electronic format.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Please explain what "mandates" the Company is referring in the first paragraph of page 90 of the IRP.

RESPONSE

The term "mandates" refers generically to high or aggressive energy efficiency goals or expectations.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Please provide any analyses, workpapers or other supporting documents concerning the potential for demand response in KPC's service territory.

RESPONSE

Please see Confidential Attachment 1 to SC 1-14.

WITNESS: William K Castle