COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Investigation of the Service, Rates and Facilities of Kentucky Power Company	)))	Case No. 2021-00370

DIRECT TESTIMONY OF

BRIAN K. WEST

ON BEHALF OF KENTUCKY POWER COMPANY

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TABLE OF CONTENTS

SECTION **PAGE**

EXHIBITS

EXHIBIT	DESCRIPTION
Exhibit BKW-1	Rockport Unit Power Agreement

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I. INTRODUCTION

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

A. My name is Brian K. West. My position is Vice President, Regulatory & Finance for Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received an Associate's degree in Applied Science (Electronics Technology) and a Bachelor's degree in Business Management, both from Ohio University, in 1987 and 1988, respectively. I obtained a Master of Business Administration degree from Ohio Dominican University in 2008.

I began my utility industry career when I joined Ohio Power Company as a customer services assistant in Portsmouth, Ohio in 1989. This was a supervisor-in-training position, where I worked in each area of the office (e.g., cashiering, new service, and credit and collections) to gain knowledge and experience with every aspect of managing an area office. After completing the training program, I initially supervised meter readers in the Portsmouth office until being promoted to office supervisor in 1993. In 1997, when the area offices closed, I transferred to Chillicothe, Ohio and accepted the position of customer services field supervisor, with responsibility for managing customer field representatives who primarily worked with customers on high-bill and other inquiries.

In 2000, after American Electric Power Company ("AEP") merged with Central and South West Corporation, I moved to Columbus, Ohio, where I held various positions in Customer Operations, mostly in process improvement and supporting regulatory filings. In 2008, I transferred to AEP's Regulatory Services department, where I supported various filings before public service commissions in Arkansas, Indiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia, as well as the Public Service Commission of Kentucky ("Commission").

In 2010, I was promoted to regulatory case manager, with responsibility for energy efficiency/demand response filings, integrated resource plan filings, and various renewable filings across AEP's service territory. In 2016, I moved to a case manager role with primary responsibility for most Appalachian Power Company filings before the Public Service Commission of West Virginia, the Virginia State Corporation Commission, and the Tennessee Public Utility Commission. I accepted the position of Director of Regulatory Services for Kentucky Power in February 2019. I assumed my current position as Vice President, Regulatory & Finance for Kentucky Power Company in January 2021.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT, REGULATORY & FINANCE FOR KENTUCKY POWER?

A. I am primarily responsible for managing the regulatory and financial strategy for Kentucky Power. This includes planning and executing rate filings for both federal and state regulatory agencies, as well as filings for certificates of public convenience and necessity before this Commission. I am also responsible for managing the Company's financial operating plans. Included as part of this responsibility is the preparation and coordination of various capital and operation and maintenance ("O&M") budgets to ensure that adequate resources such as debt, equity, and cash are available to build, operate, and maintain Kentucky Power's electric system assets used to provide service to the Company's retail and wholesale customers. In this role, I manage my staff as well as direct certain members of the American Electric Power Service Corporation ("AEPSC") to perform work on Kentucky Power's behalf.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have filed testimony in support of Kentucky Power's various regulatory filings since 2019.

III. PROCEDURAL HISTORY, PURPOSE OF TESTIMONY, AND INTRODUCTION OF WITNESSES

Q. WHAT DO YOU UNDERSTAND THE SCOPE OF THIS PROCEEDING TO BE?

A. It is my understanding based on the Commission's December 1, 2023 Order in this case that the purpose of this proceeding is for the Commission "to gather evidence … [demonstrating] whether Kentucky Power is meeting its legal obligation to provide adequate electric service in its service territory, which includes the legal obligation to have sufficient capacity to serve customers' energy needs."[1]

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

A. The purpose of my testimony is to provide an overview of the direct testimony that the Company is filing in response to the Commission's June and December 2023 orders in this proceeding and to describe Kentucky Power's provision of adequate service to its customers. Additionally, I describe the process Kentucky Power utilizes to ensure it

[1] Order at 8 (Dec. 1, 2023).

provides this adequate service and explain how it has done so in light of the recent period of supply resource transition.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring Exhibit BKW-1, a copy of the Rockport Unit Power Agreement ("Rockport UPA").

Q. PLEASE PROVIDE AN OVERVIEW OF THE OTHER DIRECT TESTIMONY THE COMPANY IS SUBMITTING IN RESPONSE TO THE COMMISSION'S ORDERS IN THIS CASE.

A. Kentucky Power is also filing direct testimony from the following witnesses:

- Timothy C. Kerns – Mr. Kerns, Vice President of Generation for Appalachian Power and Wheeling Power, describes the operation of Kentucky Power's owned generation assets in advance of and during Winter Storm Elliott.
- Alex E. Vaughan – Mr. Vaughan, Managing Director – Renewables and Fuel Strategy, provides a history of Kentucky Power's capacity and energy planning within a power pool, a discussion of the Company's planning and resource procurement following termination of the Rockport UPA, and an evaluation of the Company's resource procurement decisions relating to Winter Storm Elliott.
- Jeff Plewes – Mr. Plewes, an outside expert with extensive experience in electricity market operations and policy, provides a description of PJM's capacity construct, how Kentucky Power ensures adequate capacity for its customers through its membership in PJM, how Kentucky Power's approach to meeting its PJM capacity obligations is reasonable, and how the Company's energy planning and procurement

strategies are reasonable including during the period leading up to Winter Storm Elliott.

- Tony Clark – Mr. Clark, a former state utility regulator, describes the key difference between a resource adequacy inquiry and prudence analysis and provides recommendations for a framework to address the Commission's concerns moving forward.

The testimony provided by the Company in this proceeding leads to only one conclusion: Kentucky Power, through its membership in PJM and the attendant access to PJM's geographically broad and technologically diverse portfolio of generation assets, provides adequate service, and then some, to its customers.

IV. KENTUCKY POWER PROVIDES ADEQUATE SERVICE

Q. DOES KENTUCKY POWER PROVIDE ADEQUATE SERVICE TO ITS CUSTOMERS?

A. Yes, absolutely. Kentucky Power provides adequate, efficient, and reasonable service, as Kentucky law requires.[2] Regarding resource adequacy, the subject of this proceeding, Kentucky Power has access to sufficient supplies of generating capacity to meet its customers' maximum estimated requirements through its membership in the PJM Interconnection ("PJM") regional transmission organization and its participation in and satisfaction of PJM's resource adequacy construct.

[2] KRS 278.030(2).

Q. HOW DOES KENTUCKY POWER'S MEMBERSHIP IN PJM PROVIDE THE COMPANY WITH THE CAPACITY NECESSARY TO MEET ITS CUSTOMERS' REQUIREMENTS?

A. As I noted above, the specific details of PJM's operations are described in detail in the testimony of Company Witnesses Vaughan and Plewes. Generally, however, the simplest way of thinking about PJM is that it is a resource pool sized to meet the requirements, in all hours of all seasons, of each of its members including Kentucky Power. Each member of PJM is required to provide its allocated capacity share to the resource pool as a condition of its membership. The membership in PJM, in turn, gives each member access to a geographically broad and technologically diverse portfolio of generation assets managed to provide energy to meet the energy requirements of all of PJM's members, including Kentucky Power.[3] Kentucky Power's membership in PJM is not a backstop for its owned generation. Instead, it is a cost-effective tool to provide the capacity and energy necessary to meet its customers' maximum estimated requirements.

Q. HOW DOES KENTUCKY POWER MEET ITS PJM CAPACITY OBLIGATIONS?

A. PJM members are able to meet their capacity obligations to the broader pool in one of two ways, as a Fixed Resource Requirement ("FRR") participant or as a Reliability Pricing Model ("RPM") participant. At a high level, FRR participants meet their capacity requirement by identifying owned or contracted-for capacity resources that they commit to PJM, while RPM members meet their obligations solely through participation in PJM's capacity market, in which they make financial payments to PJM, which PJM then disburses to generators who are selected in an auction to provide capacity to the system. Kentucky

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[3] Company Witness Plewes provides an overview of the differences between capacity and energy and the applicability of that difference to the scope of this proceeding.

Power currently meets its capacity obligations to PJM and its customers as an FRR participant. Kentucky Power evaluates annually whether to continue to meet its PJM capacity obligations as an FRR entity or to elect RPM participation, which would require a five-year RPM commitment, and informs the Commission of its decision.[4] To satisfy its FRR obligations, the Company commits to PJM 1,075 MW of owned capacity from Big Sandy Unit 1 and its undivided 50% interest in the Mitchell Generating Station as well as the bilateral capacity purchases necessary to fulfill its allocated share of the system's capacity requirements. For the balance of the 2022/2023 PJM planning year after expiration of the Rockport UPA in December 2022, Kentucky Power committed 152.4 MW of bilateral unforced capacity purchases to PJM to ensure it continued to satisfy its FRR obligations and maintained access to the PJM resource pool to serve its customers' requirements.

Q. DOES KENTUCKY POWER'S APPROACH PROVIDE BENEFIT TO KENTUCKY POWER'S CUSTOMERS?

A. Yes. Kentucky Power's customers benefit in several respects. First, the PJM pool contains a broad array of generation resource types, which enhances reliability by diversifying risk across different generation technologies that will not experience correlated outages. The pool also is geographically diverse, enhancing reliability by reducing risk arising from localized weather conditions. Second, Kentucky Power benefits from PJM's pool-wide approach to reliability. Company Witnesses Vaughan and Plewes discuss this in more detail, but, at a high level, the PJM pool peaks in the summer. Thus, when PJM procures resources capable of year-round performance in a quantity sufficient to meet the summer

[4] Kentucky Power filed notice of its most recent decision on May 4, 2023 in the post-case correspondence file of Case No. 2017-00179.

peak, the result is that PJM has very large reserves in the winter. Kentucky Power benefits from this because its own summer peak is lower than its winter peak. To meet PJM's requirements, Kentucky Power must contribute to PJM a quantity of capacity sufficient to meet its summer peak, and it can then benefit from a PJM-wide generation resource pool that will necessarily have sufficient capacity to satisfy Kentucky Power's winter peak. This is cheaper for customers than if Kentucky Power were not part of a summer-peaking pool. Third, Kentucky Power's customers benefit from access to a power pool that, during most hours, can deliver energy to Kentucky Power customers more cheaply than Kentucky Power's owned generation resources. Overall, access to the PJM energy market saves customers tens of millions of dollars a year in energy costs.

Q. FROM A RESOURCE ADEQUACY PERSPECTIVE, WOULD IT BE BETTER FOR KENTUCKY POWER'S CUSTOMERS IF THE COMPANY OWNED GENERATION OR WERE A PARTY TO POWER PURCHASE AGREEMENTS ("PPAs") EQUAL TO ITS PEAK LOAD?

A. No. Customers would be paying for unnecessary capacity. As described in detail in the testimony of Company Witnesses Vaughan and Plewes, so long as the Company satisfies its capacity obligations in PJM's resource adequacy construct, there is *de minimis* reliability benefit in owning or contracting for additional capacity equal to the difference between Kentucky Power's summer and winter peaks. That is because PJM's resource adequacy construct already ensures that there is sufficient capacity to cover all hours of the year, including Kentucky Power's winter peak.

Although there is no reliability benefit, there can be economic benefits to owning or contracting for capacity. Specifically, owned generation and PPAs can act as a financial hedge against exposure to spot market energy purchases in PJM. But owning or contracting for generation also comes with costs. Any owned asset remains part of a utility's rate base (or cost of service) with fixed costs to be recovered from customers whether or not it is economically dispatched. Similarly, if a utility is a party to a PPA, it will pay the PPA price for the energy it is required to purchase, based on the structure of the PPA, and potentially regardless of whether the market price is higher or lower. Owned generation and PPAs can be an important part of a utility's capacity resource mix, but a thorough analysis of cost is important to identify the right balance of owned/contracted resources versus reliance on the energy spot market.

Q. IS KENTUCKY POWER'S USE OF A RESOURCE POOL TO MEET ITS CUSTOMERS' REQUIREMENTS NEW?

A. No. As described in more detail by Company Witness Vaughan, Kentucky Power has been a member of a resource pool for decades. In fact, prior to the construction of Big Sandy Unit 1, the Company purchased all of its capacity and energy from affiliates in the AEP East Pool. As described in the testimony of Company Witness Plewes, it is not uncommon for utilities to meet customers' requirements exclusively through membership in a resource pool such as PJM.

Q. HAS THE COMPANY'S MEMBERSHIP IN PJM EVER FAILED TO PROVIDE THE COMPANY'S CUSTOMERS WITH ADEQUATE SERVICE?

A. No. Since at least 2004, when Kentucky Power joined PJM, the Company has not experienced a supply-related outage.

Q. HAS THE PJM RESOURCE ADEQUACY CONSTRUCT BEEN GOOD FOR CUSTOMERS DURING EXTREME WEATHER EVENTS AS WELL?

A. Yes. The Company has been able to rely on its membership in PJM to meet its customers' needs even in the most extreme conditions. For example, during December 2022's Winter Storm Elliott, the Company was able to meet all of its customers' heating and lighting needs without a single load shedding event. Kentucky Power, through its membership in PJM, kept its customers' lights and heat on.

Q. DID OTHER UTILITIES IN KENTUCKY SHED LOAD DURING WINTER STORM ELLIOTT?

A. Yes. It is my understanding that LG&E and KU, as well as TVA, none of whom are members of a regional transmission system such as PJM, had to shed load during Winter Storm Elliott via rolling blackouts. Mr. Plewes provides more information on how utilities adjacent to PJM were impacted by Winter Storm Elliott and their reliability performance during the storm in comparison.

Q. ARE THE UTILITIES IN KENTUCKY THAT WERE UNABLE TO MEET THEIR CUSTOMERS' REQUIREMENTS DURING WINTER STORM ELLIOTT SUBJECT TO SHOW CAUSE ORDERS IMPLICATING THE EXTREME REMEDY IN KRS 278.018(3)?

A. No. To my understanding, only Kentucky Power is subject to such an investigation. I want to be clear, I do not think that a failure to meet customer requirements during a historic weather event such as Winter Storm Elliott means that a utility has failed to provide adequate service. Although I am not a lawyer, it is my understanding that "adequate service" as defined in KRS 278.010 requires sufficient capacity to "meet the maximum *estimated* requirements…" It seems both inappropriate and counterproductive to find a utility to have not provided "adequate service" because of outages during an extreme event that exceeded "maximum estimated requirements." Nevertheless, the fact that Kentucky Power's membership in the PJM resource pool allowed the Company to keep its customers' lights and, critically, heat on *even* during the extreme conditions experienced during Winter Storm Elliott is clear and convincing evidence that Kentucky Power is providing adequate service to its customers.

Q. GIVEN KENTUCKY POWER'S PERFORMANCE DURING WINTER STORM ELLIOTT, INCLUDING ITS PERFORMANCE RELATIVE TO OTHER KENTUCKY UTILITIES, IS THIS PROCEEDING THE APPROPRIATE AVENUE THROUGH WHICH TO EVALUATE THE COMPANY'S SERVICE?

A. No, it is not. The Show Cause Order is inconsistent with the Commission's approval of the Company's decision to join PJM in the first place, a decision made to reap the reliability and economic benefits provided by the nation's largest power pool. To the extent the Commission believes that the manner through which the Company provides adequate service to its customers is now imprudent as a matter of cost or economics, that is a wholly different inquiry. As described in the testimony of Company Witness Clark, such an economic inquiry is important, but is appropriately dealt with in a traditional prudence/cost recovery proceeding,[5] not in an order to show cause for failure to provide adequate service.

[5] See Order, In the Matter of: Electronic Application Of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To The Extraordinary Fuel Charges Incurred By Kentucky Power Company In Connection With Winter Storm Elliott In December 2022, Case No. 2023-00145 (Ky. P.S.C. June 23, 2023). This order has been appealed by the Company and remains pending before Franklin Circuit Court in Case No. 23-CI-00682.

Q. WHAT SHOULD THE COMMISSION DO TO PROTECT CUSTOMERS FROM A GENERATION RELIABILITY AND FINANCIAL PERSPECTIVE WHEN OUTLIER EVENTS LIKE WINTER STORM ELLIOTT OCCUR?

A. The Commission may consider, on an appropriately developed record, whether utilities in Kentucky should do more as a general matter to be prepared for outlier events like Winter Storm Elliott, balancing both the costs and incremental benefits of such efforts. That, however, would be a completely different proceeding from the instant one. As Mr. Clark explains, such a proceeding should be forward-looking, general in its application to all utilities in Kentucky, and culminate with clear guidance to utilities regarding the Commission's expectations.

V. KENTUCKY POWER'S RESOURCE PLANNING

Q. PLEASE DESCRIBE HOW KENTUCKY POWER ENSURES THAT ITS CUSTOMERS' SUPPLY REQUIREMENTS ARE MET.

A. Kentucky Power periodically evaluates its anticipated customer demands against its supply portfolio to determine whether its supply portfolio should be adjusted to meet changing demands. Through its integrated resource planning ("IRP") process, the Company reviews its long-term supply position based on forecasts of customer demand and market pricing and develops a strategic plan for meeting its customers' requirements. The Company also routinely evaluates its short-term supply position and makes tactical decisions regarding financial energy purchases to meet customers' requirements. In both its long-term, strategic supply planning and its short-term, tactical decisions, the Company is guided by the principle of providing adequate supply to meet its customers' requirements in a cost-effective manner.

Q. HOW DOES KENTUCKY POWER PERFORM THIS WORK?

A. The Company directs experts made available to it from its affiliate, the American Electric Power Service Corporation ("AEPSC"), on both long-term and short-term supply planning. Company Witness Vaughan describes this work in detail in his testimony. By using AEPSC experts, Kentucky Power and customers benefit from those subject matter experts' expertise, gained through full time interaction with the markets, at a fraction of the cost the Company would incur to have a comparable level of expertise fully in-house. In the end, however, the ultimate decision maker on resource planning matters (and, for that matter, all decisions relating to the Company's operation) is Kentucky Power, led by its President and Chief Operating Officer, Cynthia Wiseman.

Q. PLEASE DESCRIBE KENTUCKY POWER'S RECENT RESOURCE PLANNING ACTIVITIES.

A. Kentucky Power's recent resource planning activities have been driven largely by two factors. The first is a decrease in load served by the Company. As a result of the closure of several large industrial facilities, including AK Steel and Kentucky Electric Steel, and a loss of population in the service territory, the Company's load decreased by approximately 25% during the period from 2008 through 2022. The second factor is the expiration of the Company's unit power agreement for a portion of the output of the Rockport Generating Plant (the "Rockport UPA"). A copy of the Rockport UPA is provided as Exhibit BKW-1. The expiration of the Rockport UPA required the Company to obtain additional capacity to meet its obligations as an FRR member of PJM and to maintain access to the PJM resource pool to meet customer requirements.

Q. WHEN DID THE ROCKPORT UPA EXPIRE?

A. The Rockport UPA expired on December 8, 2022.[6]

Q. DID KENTUCKY POWER HAVE A RIGHT TO EXTEND OR RENEW THE ROCKPORT UPA?

A. No. The Rockport UPA did not include any language that provided Kentucky Power with the right to extend or renew the agreement. By its terms, the Rockport UPA was only in effect through December 7, 2022.

Q. HOW DID KENTUCKY POWER ADDRESS THE EXPIRATION OF THE ROCKPORT UPA IN ITS RESOURCE PLANNING?

A. The Company began planning for the expiration of the Rockport UPA in its 2019 IRP. The Company's 2019 IRP reflected the expiration of the Rockport UPA and evaluated alternatives to determine the most cost-effective option to ensure that the Company was able to meet its obligations as a member of PJM to continue to enjoy the resource adequacy and economic benefits provided by the PJM resource pool. The 2019 IRP concluded that replacing the Rockport UPA with bilateral capacity purchases in a quantity sufficient to fulfill the Company's FRR requirements in PJM was the most cost-effective to maintain access to the PJM market.

Q. DOES THE 2019 IRP PLAN REPRESENT THE COMPANY'S LONG-TERM RESOURCE PLAN?

A. No. The 2019 IRP provided the Company with a "bridge" plan for addressing its supply requirements in light of the expiration of the Rockport UPA and the potential impact of the Environmental Protection Agency's Steam Electric Power Generating Effluent Guidelines

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[6] Rockport UPA, Section 6.

("ELG Rule") on the operation of the Mitchell plant. Since the 2019 IRP, the Commission has denied the Company's application for a certificate of public convenience and necessity to install the environmental controls necessary to comply with the ELG Rule[7] and directed that the Company's interest in the Mitchell plant terminate on December 31, 2028.[8]

Q. HAS THE COMPANY COMMUNICATED THE ROCKPORT UPA'S EXPIRATION TO THE COMMISSION IN OTHER PROCEEDINGS?

A. Yes. Kentucky Power conveyed to the Commission in its 2019 environmental compliance plan proceeding the Company's expectation that the Rockport UPA would terminate in 2022 and be replaced with lower cost capacity.[9] Kentucky Power indicated that "the Company [did] not intend to extend the UPA beyond December 7, 2022," and that it "currently expect[ed] that the Rockport UPA [would] expire and not be renewed."[10] The Company further stated that, if the Company's decision to not renew the Rockport UPA changed, then Kentucky Power would seek Commission approval to extend the UPA.[11] In its 2021 environmental compliance plan application regarding Mitchell Plant ELG compliance, Kentucky Power also stated that "[t]he Rockport Unit Power Agreement expires December 7, 2022. Kentucky Power has elected not to renew the agreement."[12]

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[7] Order, In the matter of: Electronic Application Of Kentucky Power Company For Approval Of A Certificate Of Public Convenience And Necessity For Environmental Project Construction At The Mitchell Generating Station, An Amended Environmental Compliance Plan, And Revised Environmental Surcharge Tariff Sheets, Case No. 2021-00004 (Ky. P.S.C. July 15, 2021).
[8] Order, In the matter of: Electronic Application Of Kentucky Power Company For Approval of Affiliate Agreements Related to the Mitchell Generating Station, Case No. 2021-00421, at p. 13 (Ky. P.S.C. May 3, 2022).
[9] *See, e.g.,* Case No. 2018-00418, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 17 (Feb. 8, 2019).
[10] *See* Case No. 2019-00389, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 6 (Jan. 31, 2020).
[11] *Id*.
[12] Case No. 2021-00004, Application at paragraph 5 (Feb. 8, 2021).

The Company also confirmed in a March 26, 2021, response to a Staff data request that its decision "not to renew the Rockport UPA [was] final."[13]

Q. ARE THERE OTHER FACTORS THAT IMPACTED, AS A PRACTICAL MATTER, THE LONG-TERM AVAILABILITY TO KENTUCKY POWER OF THE ROCKPORT PLANT'S OUTPUT AFTER DECEMBER 7, 2022?

A. Yes. As discussed by Company Witness Vaughan, neither of the Rockport units' output is available to Kentucky Power as a long-term solution as a result of regulatory approvals related to I&M's and AEG's purchase of Rockport Unit 2, the uncertainty related to that unit's retirement, the need for I&M to utilize Rockport Unit 1 to meet its capacity obligations, and the federal consent decree requirement that Rockport Unit 1 retire by December 31, 2028.[14]

Q. WHAT HAS THE COMPANY DONE TO ADDRESS LONG-TERM RESOURCE PLANNING FOR ITS CUSTOMERS?

A. On September 22, 2023, the Company issued a request for proposals for power purchase agreements to provide capacity and energy (the "2023 RFP"). The Company received proposals in response to the 2023 RFP in November 2023 and is evaluating those proposals. The Company anticipates selecting resources for further negotiations in the spring of 2024 and, if agreements are executed, filing an application for their approval with the Commission in the summer of 2024.

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[13] Case No. 2021-00004, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 5 (Mar. 26, 2021).

[14] *See United States et al., v. American Electric Power Service Corp, et al.*, Civil Action No. C2-99-1182, Order (July 17, 2019), *available at* sargus-bizhub-20190717162026 (epa.gov).

Q. EARLIER, YOU MENTIONED THAT KENTUCKY POWER WORKS WITH AEPSC ON POTENTIAL SHORT-TERM, TACTICAL FINANCIAL ENERGY PURCHASES. CAN YOU EXPLAIN THOSE EFFORTS?

A. Each month, in order to provide customers with the most economic benefit from the Company's generation portfolio, members of Kentucky Power Regulatory staff, AEPSC Commercial Operations, AEPSC Fuel Procurement, various generation personnel, and AEPSC Regulatory Services meet to review the current inventory levels at each coal-fired generating unit, the expected deliveries of coal, expected electricity demand, and market forward prices in order to forecast future coal inventory levels. This meeting also includes a discussion of scheduled outages, scheduled equipment testing, potential market events such as a transmission outage that may require PJM to commit the unit, and whether or not financial power hedging should be undertaken. These efforts are described in more detail in the testimony of Company Witness Vaughan.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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: January 1, 2019
Tariff Record Title: Kentucky Power Company Unit Power Agreement
Option Code: A

UNIT POWER AGREEMENT

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

WITNESSETH:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AEP Generating Company

By ______________________________

Vice President

KENTUCKY POWER COMPANY

By ______________________________

President

RATE DESIGN

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

DETERMINATION OF POWER BILL

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

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

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

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

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

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

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

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

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

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

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

Notes:

1. **Return on Equity**

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

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

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

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

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

2. **Operating Ratio**

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

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

3. Net In-Service Investment Ratio

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

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

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

4. 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:

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

Where:

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

and

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

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

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

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

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

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

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

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

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

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

5. Investment Balances

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

6. Allocation of Expenses

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

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

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

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

BILLINGS AND PAYMENTS

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

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

AEP GENERATING COMPANY
SAMPLE POWER BILL
SUMMARY OF MONTHLY POWER BILL

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

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

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

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

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

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

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

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

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

AEP GENERATING COMPANY
SAMPLE POWER BILL
OPERATING RATIO

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

16	Total Net In-Service Investment	

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

21	Total Non-In-Service Investment - CWIP	

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

26	Total Non-In-Service Investment - Other	

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

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

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

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

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

16	Total Unit 1 Net In-Service Investment	

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

31	Total Unit 2 Net In-Service Investment	

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

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

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

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

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

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

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

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

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

* Line 6 x Line 19 from Pg 5 of 18

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

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

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

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

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

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

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

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

12	= Imputed Coal Inventory	

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

22	= 68 day Coal Inventory	

23	Lesser of Imputed or Capped Coal Inventory	

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

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

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

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF OTHER OPERATING REVENUES

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

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

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

4		Total Steam Power Generation Expenses	

5	555-557	Other Power Supply Expenses	

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

8		Total Transmission Expenses	

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

11		Total Distribution Expenses	

12	901-905	Customer Accounts Expenses - Operation	

13	906-910	Customer Service and Informational Expenses - Operation	

14	911-917	Sales Expenses - Operation	

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

17		Total Administrative & General Exp.	

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

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

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

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

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

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

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

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

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

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

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

11		Total Electric Plant In Service	

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

19		Total Accumulated Depreciation	

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

30	186	Other Deferred Debits	

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

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

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

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

* debit <credit>

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

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

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

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

* INCLUDES ROCKPORT 1 AND 2

UNIT 1	
UNIT 2	

TOTAL	
	==========

AEP GENERATING COMPANY
SAMPLE POWER BILL
DETAIL OF NET CAPITALIZATION

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

10		Total Common Capital Stock	

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

16		Total Other Paid-In Capital	

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

21		Total Retained Earnings	

22		Total Common Equity	

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

27		Total Preferred Capital Stock	

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

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

35		Total Long-Term Debt	

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

38		Total Short-Term Debt	

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

44		Total Temporary Cash Investments	

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

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

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

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

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

27	Total Rate of Return (Net of Tax)	
		===========
28	Weighted Net Cost of Debt	
29	+ Pre-Tax Common Equity (Line 25 / .21)	

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

AEP GENERATING COMPANY (AEGCO) - ROCKPORT PLANT
SCHEDULE I - DEPRECIATION RATE CALCULATION - UNIT 1
USING BEGINNING BALANCES AT DECEMBER 31, 2017

Current Depreciation Rate through December 2018 = 3.52%

Depreciation Rate from January 2019 through December 2028 = 2.95%

YEAR	Additions	Retirements	Ending Unit Balance	Average Unit Balance	Depreciation Accrual (1)	Terminal Demolition Amount	Ending Reserve Balance	Original Cost less Reserve
2017			893,534,848				606,844,929	286,689,919
2018	0	0	893,534,848	893,534,848	31,452,427	0	638,297,356	255,237,492
2019	0	0	893,534,848	893,534,848	26,353,885	0	664,651,241	228,883,607
2020 (2)	4,180,000	0	897,714,848	895,624,848	26,415,527	0	691,066,768	206,648,080
2021	0	0	897,714,848	897,714,848	26,477,169	0	717,543,937	180,170,911
2022	0	0	897,714,848	897,714,848	26,477,169	0	744,021,106	153,693,742
2023	0	0	897,714,848	897,714,848	26,477,169	0	770,498,275	127,216,573
2024	0	0	897,714,848	897,714,848	26,477,169	0	796,975,444	100,739,404
2025	0	0	897,714,848	897,714,848	26,477,169	0	823,452,613	74,262,235
2026	0	0	897,714,848	897,714,848	26,477,169	0	849,929,782	47,785,066
2027	0	0	897,714,848	897,714,848	26,477,169	0	876,406,951	21,307,897
2028 (3)	0	0	897,714,848	897,714,848	26,477,169	5,169,287	897,714,833	15
TOTALS	4,180,000	0			296,039,191			

Rockport Unit 1 Net Plant at December 2017	286,689,919
Additions to Plant 2019-2028	4,180,000
Unit 1's Share of Terminal Demolition Cost Estimate	5,169,287
Total Amount Remaining to Depreciate	296,039,206

(1) Assuming current depreciation rates continue through December 2018 and change on January 2019 . The calculation includes an estimated addition for a CCR (2020) project .

(2) 2020 - a forecast addition to original cost of Rockport Plant totaling $4,180,000 for the ash pond relining (CCR).

(3) 2028 - AEG's share of Rockport Unit 1's terminal demolition cost ($10,338,573/2 = $5,169,287) that will be charged to accumulated depreciation.

AEP GENERATING COMPANY (AEGCO) - ROCKPORT PLANT
SCHEDULE I - DEPRECIATION RATE CALCULATION - UNIT 2
USING BEGINNING BALANCES AT DECEMBER 31, 2017

Current Depreciation Rate through December 2018 = **3.52%**

Depreciation Rate from January 2019 through December 2022 = **28.48%**

YEAR	Additions	Retirements	Ending Plant Balance	Average Plant Balance	Depreciation Accrual (1)	Terminal Demolition Amount	Ending Reserve Balance	Original Cost less Reserve
2017			82,884,421				29,705,841	53,178,580
2018	0	0	82,884,421	82,884,421	2,917,532	0	32,623,373	50,261,048
2019	0	0	82,884,421	82,884,421	23,604,967	0	56,228,340	26,656,081
2020 (2)	135,373,000	0	218,257,421	150,570,921	42,881,660	0	99,110,000	119,147,421
2021	0	0	218,257,421	218,257,421	62,158,354	0	161,268,354	56,989,067
2022 (3)	0	0	218,257,421	218,257,421	62,158,354	5,169,286	218,257,422	(1)
TOTALS	135,373,000	0			193,720,867			

Rockport Unit 2 Net Plant at December 2017	53,178,580
Additions to Plant 2019-2022	135,373,000
Unit 2's Share of Terminal Demolition Cost Estimate	5,169,286
Total Amount Remaining to Depreciate	193,720,866

(1) Assuming current depreciation rates continue through December 2018 and change on January 2019 . The calculation includes a forecasted addition of $135,373,000 for the U2 SCR (2020) project.

(2) 2020 - Forecast additions to original cost of Rockport Unit 2 totaling $135,373,000 for the Unit 2 SCR.

(3) 2022 - Unit 2's share of the terminal demolition cost ($10,338,573/2 = $5,169,286) to be charged to accumulated depreciation.

EXHIBIT NO. AEG-500

(Continued)

AEG FERC Rate Schedule 2

(Redline)

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Vice President, Regulatory & Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Brian K. West

Commonwealth of Kentucky)
) Case No. 2021-00370
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian K. West, on December 19, 2023

Marilyn Michelle Caldwell
Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841