COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)	Case No. 2014-00396

DIRECT TESTIMONY OF

PAULEY, AVERA/MCKENZIE, BARTSCH, CARLIN, DAVIS, ELLIOTT, LEFLEUR, LISTEBARGER

ON BEHALF OF KENTUCKY POWER COMPANY

SECTION III

VOLUME 1 OF 4

December 23, 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)	**Case No. 2014-00396**

DIRECT TESTIMONY OF

GREGORY G. PAULEY

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned Gregory G. Pauley, being duly sworn, deposes and says he is the President and COO of Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Gregory G. Pauley

Gregory G. Pauley

COMMONWEALTH OF KENTUCKY)
) Case No. 2014-00396
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory G. Pauley, this the 15th day of December, 2014.

Judy K Rasquist 481393

Notary Public

My Commission Expires: January 23, 2017

DIRECT TESTIMONY OF
GREGORY G. PAULEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00197

TABLE OF CONTENTS

DIRECT TESTIMONY OF
GREGORY G. PAULEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Gregory G. Pauley. My position is President and Chief Operating Officer ("COO"), Kentucky Power Company ("Kentucky Power" or the "Company.") My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40601.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor's degree from Harding University in May 1973. I also graduated from management development programs at The Ohio State University and Virginia Polytechnic Institute and State University. I currently serve as President and COO of Kentucky Power (2010). From 2006-2010 I was Director – Public Policy for American Electric Power Service Corporation ("AEPSC") working on policy issues affecting the utility industry on a national level. Prior to that, I served as Kentucky Power's Governmental/Environmental Affairs manager from 2001-2006. I have also held positions at other American Electric Power Company, Inc. ("AEP") operating units in community affairs, manager of distribution services, human resources and accounting at various operations and generation facilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided supplemental testimony and testified in Case No. 2011-00042[1], *In the Matter of: The Application of AEP Kentucky Transmission Company, Inc. For A Certificate Of Public Convenience And Necessity To Operate As A Transmission Only Public Utility.* I also provided direct and rebuttal testimony in Case No. 2012-00578[2] regarding the Company's transfer of an undivided 50% interest in the Mitchell Generating Station, and Case No. 2013-00144[3] seeking Commission approval for a biomass renewable energy purchase agreement. Finally, I provided direct testimony in the Company's most recent application for a general increase in rates, Case No. 2013-00197.

III. PURPOSE OF TESTIMONY

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

A. I provide an overview of the Company, its request to set retail rates that will provide approximately $70 million in additional annual revenue, and its

[1] *In the Matter of: The Application of AEP Kentucky Transmission Company, Inc. For A Certificate Of Public Convenience And Necessity To Operate As A Transmission Only Public Utility*, Case No. 2011-00142.

[2] *In the Matter of: Application of Kentucky Power Company for (1) A Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Associated Assets; (2) Approval of the Assumption by Kentucky Power Company of Certain Liabilities in Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred in Connection with the Company's Efforts to Meet Federal Clean Air Act Requirements; and (5) All Other Required Approvals and Relief*, Case No. 2012-00578 ("Mitchell Transfer Case").

[3] *In The Matter Of: The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals And Relief,* (Case No. 2013-00144).

application for Commission approval of its 2014 Environmental Compliance Plan. I will also introduce the witnesses who will provide testimony in this case in support of the Company's requested rate changes and the 2014 Environmental Compliance Plan.

IV. OVERVIEW OF KENTUCKY POWER'S OPERATIONS

Q. PLEASE GIVE A BRIEF OVERVIEW OF THE COMPANY AND ITS OPERATIONS.

A. Kentucky Power is a wholly owned subsidiary of AEP and is engaged in the generation, purchase, transmission and distribution of electric power. The Company serves approximately 172,000 retail customers located in 20 eastern Kentucky counties. These customers are served through our distribution operations headquarters in Ashland, Kentucky (Cannonsburg), with satellite service centers in Hazard and Pikeville. The Company also sells electric power at wholesale rates to the City of Olive Hill and the City of Vanceburg. The Company maintains a state office in Frankfort, Kentucky, which houses the office of president, governmental/environmental affairs, corporate communications, business operations support and regulatory affairs. The Company supports the communities we serve through employee involvement and corporate contributions to organizations that promote community economic growth and education. In addition, the Company further supports its communities and customers by contributing from shareholder funds $0.15 per residential customer meter per month to the Company's Home Energy Assistance Program. Similarly, under the terms of the July 2, 2013 Stipulation and Settlement Agreement in the Mitchell

Transfer Case, the Company is providing shareholder-supplied funds for economic development and job training programs in the Company's service territory.

On December 31, 2013, Kentucky Power acquired an undivided 50% interest in the environmentally-controlled Mitchell Generating Station located in Moundsville, West Virginia, along with its associated liabilities (the "Mitchell Transfer"). The Mitchell Transfer is the least-cost alternative to address the impact of emerging environmental regulations on Kentucky Power's ability to meet its customers' needs, and remains the best choice for its 172,000 customers. The Company completed the Mitchell Transfer in accordance with the Commission's October 7, 2013 Order which approved, with minor modifications accepted by the Company, the July 2, 2013 Stipulation and Settlement Agreement in in Case No. 2012-00578 ("Stipulation and Settlement Agreement").

Q. WILL THERE BE FURTHER CHANGES TO THE COMPANY'S GENERATION FLEET?

A. Yes. To comply with the Mercury and Air Toxics Rule ("MATS") rule, the Company is required to retire Big Sandy Unit 2 on June 1, 2015. In addition, because Big Sandy Unit 1 cannot be economically retrofitted with environmental controls to comply with the MATS rule and continue to operate as a coal-fired unit, Kentucky Power sought and was granted approval in Case No. 2013-00430 to convert Big Sandy Unit 1 to a gas-fired facility. It is anticipated the conversion will be complete, and the unit returned to service as a gas-fired generating facility in June 2016.

V. OVERVIEW OF THE COMPANY'S APPLICATION.

Q. WHAT ARE THE PRINCIPAL REASONS KENTUCKY POWER IS SEEKING TO ADJUST ITS RATES?

A. Under the Stipulation and Settlement Agreement in the Mitchell Transfer case (Case No. 2012-00578), Kentucky Power withdrew its then pending base rate case (Case No. 2013-00197). The Company filed Case No. 2013-00197 to obtain full recovery of the Mitchell Transfer through rates during the interim period between the date of the Mitchell Transfer (January 1, 2014) and the planned retirement date of Big Sandy Unit 2 (May 31, 2015). The Stipulation and Settlement Agreement, by contrast, provides a mechanism through which the Company recovers only a portion of the costs incurred during the interim period. It also requires the Company to file a base rate case no later than December 29, 2014. This filing complies with the Company's obligations under the Stipulation and Settlement Agreement. Obtaining the full recovery of the Company's share of the Mitchell Units and compliance with the Stipulation and Settlement Agreement are the primary drivers behind the Company's decision to seek an adjustment to its rates.

The Company is also seeking to adjust its rates to allow for expanded distribution vegetation management to permit the Company to migrate to a four-year cycle in the most expeditious and cost-effective manner. This expanded vegetation management will further enhance system reliability. Additionally, the Company is seeking this rate adjustment to recover the expenses it incurs to safely and reliably provide service to its customers.

Q. WOULD YOU PROVIDE A BRIEF OVERVIEW OF THE FILING?

A. Kentucky Power is seeking approval of a change in its retail rates that will provide approximately $70 million in additional annual revenue, an increase of 12.48% over its current revenue requirement. This increase is based on adjusted data for the historic test year ending September 30, 2014 and known and measurable adjustments to that data to present a more accurate picture of the Company's operations going forward. The major components of the Company's application which are detailed in the testimonies of the other witnesses include:

- An increase in revenue requirement to fully recover the costs associated with the Mitchell Transfer and the Big Sandy retirements. This increase is approximately $37.7 million or 54% of the total revenue requirement change.
- An increase in revenue requirement to reflect updated depreciation rates. This increase is approximately $12.8 million or 18% or the total revenue requirement change.
- An increase in revenue requirement to reflect increased vegetation management expenses to permit the Company to implement a four-year cycle and further enhance distribution system reliability. This increase is approximately $10.7 million or 15% of the total revenue requirement change.
- An increase in the revenue requirement to reflect other increases in operating expenses. This increase is approximately $8.8 million or 13% of the total revenue requirement change.
- A 10.62% return on common equity.
- The creation of four new riders: the PJM Rider, Big Sandy Retirement Rider, Big Sandy 1 Operation Rider, and the NERC Compliance and Cybersecurity Rider.
- The creation of the Kentucky Economic Development Surcharge.

Q. IS THE COMPANY ALSO SEEKING APPROVAL OF ITS 2014 ENVIRONMENTAL COMPLIANCE PLAN IN THIS APPLICATION?

A. Yes. In addition, the Company is seeking in this proceeding recovery of costs associated with the 2014 Plan. Further, in accordance with the Stipulation and Settlement Agreement in Case No. 2012-00578, Kentucky Power is seeking to recover all costs associated with the Mitchell FGD through the environmental surcharge.

Q. PLEASE ELABORATE ON THE NEED TO RECOVER INCREASING EXPENSES.

A. In a nutshell, despite increasing efficiencies, Kentucky Power's rates no longer permit the Company to recover the costs of providing reasonable service to its customers and to provide shareholders with a fair return. At least part of this is explained by the fact that Kentucky Power last filed for general rate relief as a base rate case in 2009 in Case No. 2009-00459. The Settlement Agreement in that case produced an increase in base retail electric rates of $63.66 million dollars annually.

These increased costs, along with the increased capitalization resulting from the Mitchell Transfer have reduced the Company's return on equity below levels that are fair, just and reasonable. For the test year ended September 30, 2014 Kentucky Power's return on equity was 8.43%. By contrast, the Commission-allowed rate of return on equity is 10.5%. The current case, 2014-00396, has a proposed rate of return on equity of 10.62%.

I believe the cost information presented concerning our test year and the adjustments to those numbers justify the requested increase in this case.

Q. PLEASE EXPLAIN WHAT BENEFITS THE CUSTOMERS WILL RECEIVE FROM INCREASED VEGETATION MANAGEMENT ACTIVITIES.

A. Distribution system vegetation management is a vital component of maintaining the Company's distribution system. The tree-trimming activities that the Company is proposing in this case will increase the reliability of the system. Increased reliability will result in fewer outages for our customers and a safer system. The specifics of the proposed vegetation management activities are discussed in the testimony of Company Witness Phillips.

Q. IS THE COMPANY'S FILING CONSISTENT WITH THE REQUIREMENTS OF THE MITCHELL STIPULATION?

A. Yes. As discussed above, the Stipulation and Settlement Agreement in Case No. 2012-00578 required the company to file a base rate case no later than December 29, 2014 using a test year ending September 30, 2014. The Stipulation and Settlement Agreement also includes certain provisions that the Company must propose in this case. These provisions are outlined below and are described in more detail in the testimony of other identified company witnesses:

- Pursuant to Paragraph 1 of the Stipulation and Settlement Agreement, the Company has proposed depreciation rates for Mitchell Units 1 and 2 that reflect a 2040 retirement date. More detail about the depreciation rates proposed for the Mitchell Units can be found in the testimony of Company Witness Davis.

- Pursuant to Paragraph 3 of the Stipulation and Settlement Agreement, the Company has proposed combining the current C.I.P.-T.O.D. and Q.P. tariffs into a new Industrial General Service (I.G.S.) tariff that utilizes the C.I.P.-T.O.D. rate design. More detail about the combination of current tariffs C.I.P.-T.O.D. and Q.P. into a new I.G.S. tariff can be found in the testimonies of Company Witnesses Rogness and Vaughan.

- Pursuant to Paragraph 3 of the Stipulation and Settlement Agreement, the Company has removed all coal-related plant, other coal-related capitalized costs, and coal-related expenses associated with Big Sandy Unit 1 and all plant, other capitalized costs, and expenses associated with Big Sandy Unit 2 from the cost of service study and proposes to recover those costs via the new Big Sandy Retirement Rider (described as ATR-2 in the Stipulation and Settlement Agreement). The treatment of these costs and the operation of the Big Sandy Retirement Rider is described in the testimonies of Company Witness Wohnhas and Yoder.
- Pursuant to Paragraph 6 of the Stipulation and Settlement Agreement, the Company will recover all costs associated with Mitchell Units 1 and 2 flue gas desulfurization (FGD) equipment through the environmental surcharge. The treatment of these costs under the environmental surcharge is described in the testimony of Company Witness Elliott.
- Pursuant to Paragraph 9 of the Stipulation and Settlement Agreement, the Company has expanded the availability of service under Tariff C.S.-I.R.P. to a total contract capacity of 75,000kW. The changes to Tariff C.S.-I.R.P. are described in the testimony of Company Witness Rogness.

Q. PLEASE DESCRIBE THE PURPOSE OF THE KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

A. Kentucky Power is committed to economic development in its service territory. Through the Kentucky Power Economic Advancement Program, funded by shareholders not customers, the Company has recently awarded $200,000 in development grants for three projects in its service territory. The Company has also recently partnered with 12 local banks that provided $75 million in local bank financing for upcoming capital projects. This innovative program provides investment grade opportunities for banks in the Company's service territory, thereby diversifying and strengthening their loan portfolios while deploying local capital to fund local infrastructure development. In addition, the Company is an active participant in the recently formed Shaping Our Appalachian Region ("SOAR"), established by Governor Steve Beshear and Representative Hal

Rogers to improve the economy and quality of life in Eastern Kentucky – our service territory.

Through its proposed Kentucky Economic Development Surcharge ("K.E.D.S."), the Company seeks to recover $0.15 per month from each billing account. The Company will match, with shareholder funds, the amount collected through the K.E.D.S. The funds raised through this program will be used to support key economic development activities within our region. The details of the K.E.D.S. program are described in the testimony of Company Witness Rogness. The K.E.D.S. will allow the Company to partner with its customers in supporting needed economic development in its service territory.

Q. WHY IS THE COMPANY PROPOSING A NERC CYBERSECURITY RIDER?

A. One of the new riders proposed by Kentucky Power in this case is the NERC Compliance and Cybersecurity Rider (the "NCCR"). The purpose of the NCCR is to provide a vehicle for the Company to recover costs incurred in complying with NERC standards for cybersecurity measures. As cybersecurity threats grow, NERC, as the entity responsible for ensuring the reliability of the bulk power system in North America, is increasing the number of critical infrastructure protection standards. These standards can require significant capital investment and O&M expenditures to ensure compliance. Kentucky Power and its parent AEP stand at the forefront of industry efforts to plan and prepare for the NERC compliance and cybersecurity obligations; however, unforeseen changes in NERC standards and compliance costs cannot be absorbed into the existing operating budget. The NCCR provides a mechanism for the Company to recover those costs following Commission review. More detailed discussions of the need for and the proposed operation of the NCCR are found in the testimonies of Company Witnesses Stogran and Wohnhas.

Q. PLEASE DESCRIBE THE TESTIMONY SUPPORTING KENTUCKY POWER'S APPLICATION?

A. The Company's proposed changes in annual revenue requirement as well as the adjustments to test year revenues, operating expenses, rate base and capitalization are supported by the following witnesses:

WITNESS	**SUBJECT AREA**
William E. Avera & Adrien M. McKenzie	Cost of Equity/Return on Equity
Jeffrey B. Bartsch	Taxes and Certain Adjustments
Andrew R. Carlin	Employee Compensation
David A. Davis	Depreciation Study
Amy J. Elliott	Environmental Compliance Plan; Mitchell FGD Revenue Requirement
Jeffery D. LaFleur	Generation Assets; Reasonableness of the Generation non-fuel on going O&M expenses; Support Removal of Coal Related Assets from Big Sandy Plant; Support the Capital Projects included in the 2014 Environmental Plan
Shannon R. Listebarger	Jurisdictional COS
Hugh E. McCoy	Pension Plan Costs
John M. McManus	Environmental Issues
Everett G. Phillips	Reliability/Vegetation Management
Marc D. Reitter	Cost of Capital
John Rogness	Adjustments; Tariff Revisions
Jason M. Stegall	Revenue Adjustments; Class Cost of Service Study
Kevin Stogran	NERC Compliance/Cybersecurity

WITNESS	SUBJECT AREA
Alex Vaughan	Big Sandy 1 Operation Rider Revenue Requirement; PJM Rider; Certain Adjustments; Off System Sales Normalization; Rate Design
Ranie Wohnhas	Proposed rate adjustment; tariff revisions; capitalization adjustments; amortization of regulatory assets and deferred costs; other adjustments; riders
Jason Yoder	Revenue Requirement for Big Sandy Retirement Rider; Certain Adjustments; Accounting Issues and Amortization for Certain Adjustments

Q. ARE THE RATES REQUESTED BY KENTUCKY POWER FAIR, JUST AND REASONABLE?

A. Yes. Kentucky Power's goal is to provide reliable and cost-effective service to its customers while also producing a reasonable return for its shareholders. The fundamental changes facing the electric utility industry, primarily in the form of evolving and stricter environmental regulations, have forced Kentucky Power into once-in-a-generation changes in its generation portfolio. This change in the generation portfolio necessitates a change in the Company's annual revenue requirement. Kentucky Power's proposed rate changes represent fair, just and reasonable rates that will allow it to continue to provide the service that customers require and the earnings that the Company's shareholders deserve. Even with the proposed increase, the customers of Kentucky Power will continue to enjoy electricity priced below the national average.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	**)))))))**	**Case No. 2014-00396**

DIRECT TESTIMONY
OF
WILLIAM E. AVERA
AND
ADRIEN M. MCKENZIE

ON BEHALF OF

KENTUCKY POWER COMPANY

VERIFICATION

Dr. William E. Avera being duly sworn deposes and says he is the President of FINCAP, Inc., and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

William E Avera

DR. WILLIAM E. AVERA

STATE OF TEXAS)
) CASE NO. 2014-00396
COUNTY OF TRAVIS)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Dr. William E. Avera this 16th day of December, 2014.

Notary Public

My Commission Expires: 1/10/2015

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm. Exp. Jan. 10, 2015

VERIFICATION

Adrien M. McKenzie being duly sworn deposes and says he is a Vice President of FINCAP, Inc., and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Adrien M .McKenzie

STATE OF TEXAS	)	
	)	CASE NO. 2014-00396
COUNTY OF TRAVIS	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Adrien M .McKenzie this 16th day of December, 2014.

WESLEY READDICK
NOTARY PUBLIC
STATE OF TEXAS
EXPIRES
06/20/2018

Notary Public

My Commission Expires: 6/20/2018

<u>**TABLE OF CONTENTS**</u>

EXHIBITS TO DIRECT TESTIMONY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESS.

A. Our names are William E. Avera and Adrien M. McKenzie. Our business address is 3907 Red River, Austin, Texas.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. We are financial, economic, and policy consultants to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. A description of our background and qualifications, including resumes containing the details of our experience, is attached as Exhibit WEA/AMM 1 (Avera) and Exhibit WEA/AMM 2 (McKenzie).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to present to the Kentucky Public Service Commission ("KPSC") our independent assessment of the fair rate of return on equity ("ROE") that Kentucky Power Company ("Kentucky Power" or "the Company") should be authorized to earn on its investment in providing electric utility service. In addition, we also examined the reasonableness of Kentucky Power's capital structure, considering both the specific risks faced by the Company, as well as other industry guidelines.

Q. WHICH OF YOU INTENDS TO APPEAR IN THE EVENT OF A HEARING IN THIS PROCEEDING?

A. While we are jointly sponsoring all aspects of this testimony in its entirety, we anticipate that Dr. Avera will appear to sponsor our joint testimony and respond to cross examination in any future hearings before the KPSC in this proceeding.

Q. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A. We are familiar with the organization, finances, and operations of Kentucky Power from our firm's participation in prior proceedings before KPSC. In connection with the present filing, we considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to Kentucky Power and its parent company, American Electric Power Company, Inc. ("AEP"). We also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with our experience in the fields of finance and utility regulation, have given us a working knowledge of the issues relevant to investors' required return for Kentucky Power, and they form the basis of our analyses and conclusions.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. After first summarizing our conclusions and recommendations, we briefly review the Company's operations and finances. We then examine current conditions in the capital markets and their implications in evaluating a fair ROE for Kentucky

Power. With this as a background, we present well-accepted quantitative analyses of the current cost of equity for a reference group of comparable-risk electric utilities. Our ROE recommendations are based on the results of the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on allowed ROEs for electric utilities, which are all methods that are commonly relied on in regulatory proceedings. Considering the cost of equity estimates indicated by these primary analyses, a fair ROE for Kentucky Power is evaluated taking into account the Company's requirements for financial strength that provides benefits to customers, as well as flotation costs, which are properly considered in setting a fair ROE.

Finally, we test our recommended ROE for Kentucky Power against alternative checks of reasonableness, including the traditional Capital Asset Pricing Model ("CAPM"), reference to expected rates of return for electric utilities, and application of the DCF model to a select group of low risk non-utility firms.

II. RETURN ON EQUITY FOR KENTUCKY POWER

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents our conclusions regarding the fair ROE for Kentucky Power. This section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Summary of Conclusions

Q. WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR KENTUCKY POWER?

A. Based on the results of our analyses and the economic requirements necessary to support continuous access to capital, we recommend an ROE for Kentucky Power of 10.62%.

Q. PLEASE SUMMARIZE THE RESULTS OF THE QUANTITATIVE ANALYSES ON WHICH YOUR CONCLUSIONS WERE BASED.

A. Our ROE recommendations are based on the results of three primary methods – the DCF model, the ECAPM, and the risk premium approach. The cost of common equity estimates produced by these three primary analyses are presented on page 1 of Exhibit WEA/AMM 3, and summarized below:

- In order to reflect the risks and prospects associated with Kentucky Power's jurisdictional utility operations, our analyses focused on a proxy group of 13 other utilities with comparable investment risks;
- Based on our evaluation of the strengths and weaknesses of the DCF, ECAPM, and risk premium methods, we concluded that 10.62% represents a fair ROE for the proxy group of utilities:
  - After considering the relative merits of the alternative growth rates and giving little weight to the internal, "br+sv" growth measures, our evaluation of the DCF results implied a cost of equity in the 9.4% to 10.1% range.
  - The forward-looking ECAPM estimates suggested an ROE in the range of 11.3% to 12.4%;
  - The utility risk premium approach implies an ROE estimate on the order of 10.1% to 11.3%;
  - Widespread expectations for higher interest rates emphasize the implication of considering the impact of projected bond yields in evaluating the results of the ECAPM and risk premium methods;

- Taken together, these results indicated that the “bare bones cost of equity,” that is, the cost of equity before flotation costs, falls within a range of 9.7% to 11.3%, with a midpoint of 10.5%;
- Adding a flotation cost adjustment of 12 basis points to this bare bones cost of equity resulted in an ROE of 10.62% for the proxy group.

Apart from the expected upward trend in capital costs, a cost of equity of 10.62% is consistent with the need to support financial integrity and fund capital investment even during times of adverse capital market conditions.

Q. DID YOU EVALUATE OTHER CHECKS OF REASONABLENESS?

A. Yes. We also performed alternative tests to confirm the results of our primary methods and our conclusions as to a fair and reasonable ROE for Kentucky Power. The results of these well-respected and commonly referenced ROE benchmarks are presented on page 2 of Exhibit WEA/AMM 3, and summarized below:

- Applying the traditional CAPM approach implied a current cost of equity of 10.7% to 11.6%;
- Expected returns for electric utilities suggested an ROE range of 9.9% to 10.6%, excluding any adjustment for flotation costs; and
- Application of the DCF model to a select group of low-risk firms in the non-utility sector resulted in average ROE estimates ranging from 10.4% to 10.9%.
- Therefore, these benchmark tests of reasonableness confirm that a 10.62% ROE falls in the reasonable range to maintain Kentucky Power’s financial integrity, provide a return commensurate with investments of comparable risk, and support the Company’s ability to attract capital.

Q. WHAT IS YOUR CONCLUSION REGARDING THE IMPACT OF REGULATORY MECHANISMS IN EVALUATING A FAIR ROE FOR KENTUCKY POWER?

A. Investors recognize that the use of adjustment mechanisms and future test years is widely prevalent in the utility industry, and the relative impact is already considered in the data for our proxy group. As a result, any mitigation in risks associated with Kentucky Power's ability to attenuate regulatory lag through adjustment mechanisms or its election of a future test year is already reflected in the results of the quantitative methods presented in our testimony. The KPSC's adjustment mechanisms act to level the playing field, placing the Company on equal footing with its peers in the industry. As a result, no adjustment to the ROE is justified or warranted.

Q. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S REQUESTED CAPITAL STRUCTURE?

A. The Company's 46% common equity ratio falls below the average capitalization maintained by the proxy group of utilities based on data at year-end and near-term expectations. Because a capitalization that contains relatively more debt leverage implies greater financial risk, it also implies a higher required rate of return to compensate investors for bearing additional uncertainty. As a result, Kentucky Power's capitalization represents a conservative basis on which to calculate an overall rate of return for the Company.

III. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of Kentucky Power. In addition, it examines conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair ROE.

A. Kentucky Power Company

Q. BRIEFLY DESCRIBE KENTUCKY POWER AND ITS ELECTRIC UTILITY OPERATIONS.

A. Headquartered in Frankfort, Kentucky, Kentucky Power is a wholly-owned subsidiary of AEP principally engaged in the generation, transmission and distribution of electric power. The Company provides electric service to approximately 172,000 retail customers in eastern Kentucky. In addition to providing retail electric utility service, the Company also sells electric power at wholesale to municipalities and other utilities. At year-end 2013, Kentucky Power's total assets amounted to $2 billion, with total revenues amounting to approximately $667 million.

Kentucky Power operates approximately 1,858 megawatts (MW) of coal-fired generating capacity, consisting of two units at the Big Sandy plant, and a 50% interest in the Mitchell plant. The Company also purchases a share of the Rockport plant under a long-term unit power agreement, and operates under a

Power Coordination Agreement with Indiana Michigan Power Company and Appalachian Power Company. Big Sandy Unit 2 will cease operation as a coal-fired facility in 2015. The Company has received approval to convert Unit 1 at Big Sandy to a natural gas fired facility.

The Company's transmission and distribution facilities consist of over 11,000 miles of transmission and distribution lines. KPCo is a member of the PJM Interconnection, LLC ("PJM"), a FERC-approved regional transmission organization, and provides transmission service pursuant to the PJM Open Access Transmission Tariff. The Company's retail utility operations are subject to the jurisdiction of the KPSC, with wholesale transmission operations being regulated by FERC.

Q. PLEASE DESCRIBE THE AEP SYSTEM.

A. AEP delivers electricity to more than 5 million customers across 11 states, including Ohio, Indiana, West Virginia, Virginia, Kentucky, Michigan, Tennessee, Oklahoma, Texas, Louisiana, and Arkansas. AEP is one of the largest electric utilities in the U.S., with its combined utility system including over 38,000 MW of generating capacity and over 40,000 miles of transmission lines. AEP's electric utility subsidiaries rely primarily on coal-fired generation, which makes up approximately 60% of total capacity, including purchased power agreements ("PPAs"). During 2013, AEP's revenues totaled approximately $15.4 billion, with total assets at year-end of $56.4 billion.

Q. WHERE DOES KENTUCKY POWER OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN ELECTRIC UTILITY PLANT?

A. As a wholly-owned subsidiary of AEP, the Company obtains common equity capital solely from its parent, whose common stock is publicly traded on the New York Stock Exchange. In addition to capital supplied by AEP, Kentucky Power also issues debt securities directly under its own name.

Q. WHAT CREDIT RATINGS HAVE BEEN ASSIGNED TO THE COMPANY?

A. Kentucky Power is assigned a corporate credit rating of BBB by Standard & Poor's Corporation ("S&P"). While an industry-wide credit review led Moody's Investors Service ("Moody's") to upgrade the ratings of most electric utilities in 2014,[1] Kentucky Power's long-term issuer rating was left unchanged at Baa2.

Q. DOES KENTUCKY POWER ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A. Yes. Kentucky Power will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund investment in new facilities. S&P noted that Kentucky Power "will need external funding sources" to meet its cash flow needs,[2] while Moody's observed that additional equity contributions will be required if the Company is to maintain an appropriate capital structure.[3]

---

[1] Moody's Investors Service, "US utility sector upgrades driven by stable and transparent regulatory frameworks," *Special Comment* (Feb. 3, 2014).

[2] Standard & Poor's Corporation, "Summary: Kentucky Power Co.," *Research* (May 5, 2014).

[3] Moody's Investors Service, "Credit Opinion: Kentucky Power Company," *Global Credit Research* (Feb. 10, 2014).

Q. ARE THERE REGULATORY MECHANISMS THAT AFFECT KENTUCKY POWER'S RATES FOR UTILITY SERVICE?

A. Yes. In addition to the ability to recover fuel and purchased power costs, Kentucky Revised Statute 278.183 provides, in part, that "… a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal …" Consistent with this statutory provision, the KPSC has approved an environmental cost recovery mechanism ("ECR") for the Company that allows for recovery of related costs. In addition, Kentucky Power operates under a Demand Side Management ("DSM") rate mechanism that provides for recovery of DSM costs – including a provision to earn a return of and on capital investment for DSM programs.

Q. DOES THE FACT THAT KENTUCKY POWER OPERATES UNDER CERTAIN REGULATORY MECHANISMS WARRANT ANY ADJUSTMENT IN YOUR EVALUATION OF A FAIR ROE?

A. No. Investors recognize that Kentucky Power is exposed to significant risks associated with the ability to recover rising costs and investment on a timely basis, and concerns over these risks have become increasingly pronounced in the industry. The KPSC's rate adjustment mechanisms are a tool to address these risks, but they do not eliminate them. In addition, investors also recognize that the heightened scrutiny associated with periodic regulatory review under tracking mechanisms exposes the Company to increased risk for retroactive reviews and disallowances.

While the regulatory mechanisms approved for Kentucky Power partially attenuate exposure to attrition in an era of rising costs and investment, this leveling of the playing field only serves to address factors that could otherwise impair the Company's opportunity to earn its authorized return, as required by established regulatory standards.

Q. DO THESE MECHANISMS SET KENTUCKY POWER APART FROM OTHER FIRMS OPERATING IN THE UTILITY INDUSTRY?

A. No. Adjustment mechanisms, cost trackers, and reliance on forward-looking test periods have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers through a variety of regulatory mechanisms.

B. Outlook for Capital Costs

Q. DO CURRENT CAPITAL MARKET CONDITIONS PROVIDE A REPRESENTATIVE BASIS ON WHICH TO EVALUATE A FAIR ROE?

A. No. Current capital market conditions reflect the legacy of the "Great Recession," and are not representative of what investors expect in the future. Investors have had to contend with a level of economic uncertainty and capital market volatility that has been unprecedented in recent history. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. In response to heightened uncertainties in recent years, investors have repeatedly sought a safe haven in U.S. government bonds. As a result of this "flight to safety," Treasury bond yields have been pushed significantly lower in the face of political, economic, and capital market risks. In addition, the Federal Reserve has implemented measures designed to push interest rates to historically low levels in an effort to stimulate the economy and bolster employment and investor confidence in the face of heightened economic risk.

Q. HOW DO CURRENT YIELDS ON PUBLIC UTILITY BONDS COMPARE WITH WHAT INVESTORS HAVE EXPERIENCED IN THE PAST?

A. Despite recent increases, the yields on utility bonds remain near their lowest levels in modern history. Figure 1, below, compares the October 2014 average yield on long-term, triple-B rated utility bonds with those prevailing since 1968:

FIGURE 1
BBB UTILITY BOND YIELDS – CURRENT VS. HISTORICAL

As illustrated above, prevailing capital market conditions, as reflected in the yields on triple-B utility bonds, are an anomaly when compared with historical experience. Similarly, while 10-year Treasury bond yields may reflect a modest increase from all-time lows of less than 2.0%,[4] they are hardly comparable to historical levels.[5] Federal Reserve President Charles Plosser recently observed that U.S. interest rates are unprecedentedly low, and "outside historical norms."[6]

Q. ARE THESE VERY LOW INTEREST RATES EXPECTED TO CONTINUE?

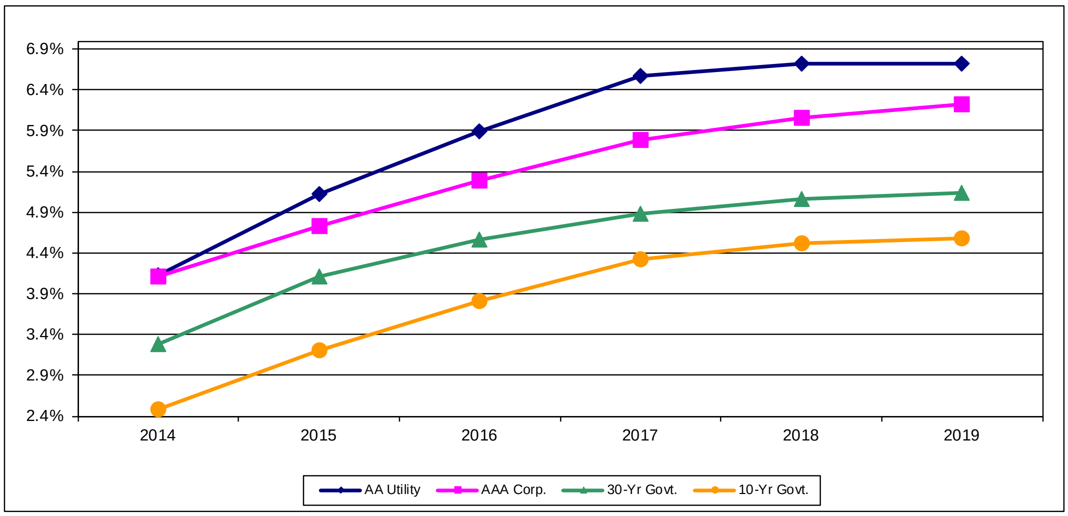
A. No. Investors do not anticipate that these low interest rates will continue into the future. It is widely anticipated that as the economy continues to stabilize and resumes a more robust pattern of growth, long-term capital costs will increase significantly from present levels. Figure 2 below compares current interest rates

---

[4] The average yield on 10-year Treasury bonds for the six-months ended October 2014 was 2.46%.
[5] Over the 1968-2014 period illustrated on Figure 2, 10-year Treasury bond yields averaged 6.76%.
[6] Barnato, Katy, "Fed's Plosser: Low rates 'should make us nervous'," *CNBC* (Nov. 11, 2014).

on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE 2
INTEREST RATE TRENDS



<u>Source:</u>

Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 22, 2014)
IHS Global Insight, U.S. Economic Outlook at 79 (May 2014)
Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
Blue Chip Financial Forecasts, Vol. 33, No. 6 (Jun. 1, 2014)

These forecasting services are highly regarded and widely referenced, with FERC incorporating forecasts from IHS Global Insight and the EIA in its preferred DCF model for natural gas and oil pipelines, as well as for electric transmission utilities. As evidenced above, there is a clear consensus in the investment community that the cost of long-term capital will be significantly higher over 2015-2019 than it is currently.

Q. DO RECENT ACTIONS OF THE FEDERAL RESERVE SUPPORT THE CONTENTION THAT CURRENT LOW INTEREST RATES WILL CONTINUE INDEFINITELY?

A. No. While the Federal Reserve continues to express support for maintaining a highly accommodative monetary policy and an exceptionally low target range for the federal funds rate, it has also acted to steadily pare back its monthly bond-buying program. Citing improvement in the outlook for the labor market and increasing strength in the broader economy, the Federal Reserve elected to discontinue further purchases under its bond-buying program at its October 2014 meeting. Elimination of the Federal Reserve's bond buying program should ultimately exert upward pressure on long-term interest rates, with The Wall Street Journal observing that:

> The Fed's decision to begin trimming its $85 billion monthly bond-buying program is widely expected to result in higher medium-term and long-term market interest rates. That means many borrowers, from home buyers to businesses, will be paying higher rates in the near future.[7]

While the Federal Reserve's tapering announcements and subsequent conclusion of its asset purchases have moderated uncertainties over just when, and to what degree, the stimulus program would be altered, investors continue to face ongoing uncertainties over future modifications that could ultimately affect how quickly and how much interest rates are affected.

---

[7] Hilsenrath, Jon, "Fed Dials Back Bond Buying, Keeps a Wary Eye on Growth," *The Wall Street Journal* at A1 (Dec. 19, 2013).

Q. DOES THE CESSATION OF FURTHER ASSET PURCHASES MARK A RETURN TO "NORMAL" IN CAPITAL MARKETS?

A. No. The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400 - $500 billion. With the implementation of its asset purchase program, balances of Treasury securities and mortgage backed instruments climbed steadily, and their effect on capital market conditions became more pronounced. Table 1 below charts the course of the Federal Reserve's asset purchase program:

TABLE 1
FEDERAL RESERVE BALANCES OF
TREASURY BONDS AND MORTGAGE-BACKED SECURITIES

	(Billion $)
2008	$ 410
2009	$ 1,618
2010	$ 1,939
2011	$ 2,423
2012	$ 2,512
2013	$ 3,597
2014	$ 4,065

As illustrated above, far from representing a return to normal, the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities now amount to more than $4 trillion,[8] which is an all-time high.

[8] *Federal Reserve Statistical Release*, "Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks," H.4.1, (Oct. 30, 2014).

For now, the Federal Reserve is maintaining its policy of reinvesting principal payments from these securities – about $16 billion a month – and rolling over maturing Treasuries at auction. As the Federal Reserve recently noted:

> The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.[9]

This continued investment maintains the downward pressure on interest rates that is the hallmark of the stimulus program and the anomalous conditions currently characterizing capital markets.

Of course, the corollary to these observations is that changes to this policy of reinvestment would further reduce stimulus measures and could place significant upward pressure on bond yields, especially considering the unprecedented magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities. The International Monetary Fund noted, "A lack of Fed clarity could cause a major spike in borrowing costs that could cause severe damage to the U.S. recovery and send destructive shockwaves around the global economy," adding that, "[a] smooth and gradual upward shift in the yield curve might be difficult to engineer, and there could be periods of higher volatility when longer yields jump sharply—as recent events suggest."[10] Similarly, *The Wall Street Journal* noted investors' "hypersensitivity to Fed interest rate decisions," and expectations that higher interest rates "may come a bit sooner and

---

[9] Federal Open Market Committee, *Press Release* (Oct. 29, 2014).

[10] Talley, Ian, "IMF Urges 'Improved' U.S. Fed Policy Transparency as It Mulls Easy Money Exit," *The Wall Street Journal* (July 26, 2013).

be a touch more aggressive than expected."[11] As a *Financial Analysts Journal* article noted:

> Because no precedent exists for the massive monetary easing that has been practiced over the past five years in the United States and Europe, the uncertainty surrounding the outcome of central bank policy is so vast. . . . Total assets on the balance sheets of most developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.[12]

These developments highlight continued concerns for investors and support expectations for higher interest rates as the economy and labor markets continue to recover. With the Federal Reserve curtailing the expansion of its enormous portfolio of Treasuries and mortgage bonds, ongoing concerns over political stalemate in Washington, the threat of renewed recession in the Eurozone, and political and economic unrest in Ukraine, the Middle East, and emerging markets, the potential for significant volatility and higher capital costs is clearly evident to investors.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR KENTUCKY POWER MORE GENERALLY?

A. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets and ongoing economic and political risks. As a result, current capital costs are not representative of what is likely to prevail over the near-term future. As FERC recently concluded:

---

[11] Jon Hilsenrath and Victoria McGrane, "Yellen Debut Rattles Markets," Wall Street Journal (Mar. 19, 2014).

[12] Poole, William, "Prospects for and Ramifications of the Great Central Banking Unwind," *Financial Analysts Journal* (November/December 2013).

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses …[13]

This conclusion is supported by comparisons of current conditions to the historical record and independent forecasts. As demonstrated earlier, recognized economic forecasting services project that long-term capital costs will increase from present levels.

Given investors' expectations for rising interest rates and capital costs, the KPSC should consider near-term forecasts for public utility bond yields in assessing the reasonableness of individual cost of equity estimates and in evaluating a fair ROE for Kentucky Power from within the range of reasonableness. The use of these near-term forecasts for public utility bond yields is supported below by economic studies that show that equity risk premiums are higher when interest rates are at very low levels.

IV. COMPARABLE RISK PROXY GROUP

Q. HOW DID YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR KENTUCKY POWER?

A. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data

---

[13] Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply quantitative methods such as the DCF and ECAPM to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A. In order to reflect the risks and prospects associated with Kentucky Power's jurisdictional electric utility operations, our analyses focused on a reference group of other utilities composed of those companies included in Value Line's electric utility industry groups with:

1. Corporate credit ratings from Standard & Poor's Corporation ("S&P") of "BBB-", "BBB", or "BBB+";
2. Long-term issuer ratings from Moody's of "Baa3", "Baa2", or "Baa1";
3. Value Line Safety Rank of "2" or "3",
4. Market capitalization of $2.4 billion or greater;
5. No ongoing involvement in a major merger or acquisition; and,
6. No cuts in dividend payments during the past three months.

These criteria resulted in a proxy group composed of 13 companies, which we refer to as the "Electric Group."[14]

---

[14] As identified in our exhibits, these 13 companies are Ameren Corporation, American Electric Power Company, Inc., Black Hills Corporation, CMS Energy Corporation, Entergy Corporation, FirstEnergy Corporation, Great Plains Energy Inc., Hawaiian Electric Industries, IDACORP, Inc., PG&E Corporation, SCANA Corporation, Sempra Energy, and Westar Energy, Inc.

Q. HOW DID YOU EVALUATE THE RISKS OF THE ELECTRIC GROUP RELATIVE TO KENTUCKY POWER?

A. Our evaluation of relative risk considered four objective, published benchmarks that are widely relied on in the investment community. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (e.g., "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

Similarly, Value Line's Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole, and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in our experience Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[15]

---

[15] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUP COMPARE TO KENTUCKY POWER?

A. Table 2 compares the Electric Group with Kentucky Power across the four key indicia of investment risk discussed above. Because the Company has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, AEP:

TABLE 2
COMPARISON OF RISK INDICATORS

			Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Electric Group	BBB	Baa2	2	B++	0.76
Kentucky Power	BBB	Baa2	2	A	0.70

Q. WHAT DOES THIS COMPARISON INDICATE REGARDING INVESTORS' ASSESSMENT OF THE RELATIVE RISKS ASSOCIATED WITH YOUR ELECTRIC GROUP?

A. As shown above, the S&P and Moody's credit ratings specific to the risks of Kentucky Power are identical to the averages for the Electric Group. Similarly, AEP's Value Line Safety Rank is identical to the average for the proxy group. Although the Financial Strength Ranking and beta corresponding to AEP both suggest somewhat less risk, they fall well within the proxy group range. Considered together, this comparison of objective measures, which incorporate a broad spectrum of risks, including financial and business position and exposure to company specific factors, indicates that investors would likely conclude that the overall investment risks for Kentucky Power are comparable to those of the firms in the Electric Group.

Q. DO THE UTILITIES IN THE ELCTRIC GROUP OPERATE UNDER VARIOUS REGULATORY MECHANISMS?

A. Yes. We evaluated the regulatory mechanisms approved for the utilities in the Electric Group using data reported in the most recent Form 10-K reports filed with the Securities and Exchange Commission, which is publicly available and free of charge.[16] Reflective of industry trends, the companies in the Electric Group operate under a variety of regulatory adjustment mechanisms. As summarized on Exhibit WEA/AMM 4, these mechanisms are ubiquitous and wide ranging. For example, five of the firms benefit from mechanisms that allow for cost recovery of infrastructure investment outside a formal rate proceeding. Many of these utilities operate under revenue decoupling and other mechanisms that insulate the utility from volatility related to fluctuations in sales volumes, as well as the ability to implement periodic rate adjustments to reflect changes in a diverse range of operating and capital costs, including expenditures related to environmental mandates, conservation programs, transmission costs, and storm recovery efforts.

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt

[16] Because this information is widely referenced by the investment community, it is also directly relevant to an evaluation of the risks and prospects that determine the cost of equity.

means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. WHAT COMMON EQUITY RATIO IS USED IN KENTUCKY POWER'S CAPITAL STRUCTURE?

A. As supported in the testimony of Company Witness Reitter, the Company is proposing a common equity ratio of approximately 46%.

Q. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE ELECTRIC GROUP?

A. As shown on Exhibit WEA/AMM 5, common equity ratios for the individual firms in the Electric Group ranged from a low of 31.3% to a high of 53.6% at year-end 2013, and averaged 47.5%. Meanwhile, Value Line's three-to-five year forecast indicates an average common equity ratio of 48.3% for the Electric Group, with the individual equity ratios ranging from 37.0% to 56.0%.

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A. Utilities are facing significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the potential for turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

In addition, depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating the Company's financial risk. For example, PPAs and leases typically obligate the utility to make specified minimum contractual payments. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. Unless the utility takes action to offset this additional financial risk by maintaining a higher equity ratio, or takes other action to mitigate any additional financial risk, as we understand Kentucky Power has attempted in connection with the ecoPower REPA, the resulting leverage will weaken its creditworthiness and imply greater risk.

Q. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. The 46% common equity ratio requested by Kentucky Power falls below the average for the Electric Group at year-end 2013 and the 48.3% equity ratio based on Value Line's expectations for these utilities over the near-term. Because a capitalization that contains relatively more debt leverage implies greater financial risk, it also implies a higher required rate of return to compensate investors for bearing additional uncertainty. Based on our evaluation, we conclude that Kentucky Power's requested capital structure represents a conservative mix of capital sources from which to calculate the overall rate of return.

V. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents capital market estimates of the cost of equity. First, we address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, we describe DCF, ECAPM, and risk premium analyses conducted to estimate the cost of common equity for the proxy group of comparable risk firms. Finally, we examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q. WHAT ROLE DOES THE RATE OF RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. This investment is necessary to finance the asset base needed to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in the Bluefield[17] and Hope[18] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (e.g., U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

---

[17] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[18] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed.

Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. DOES THE FACT THAT KENTUCKY POWER IS A SUBSIDIARY OF AEP IN ANY WAY ALTER THESE FUNDAMENTAL STANDARDS UNDERLYING A FAIR ROE?

A. No. While the Company has no publicly traded common stock and AEP is its only shareholder, this does not change the standards governing the determination of a fair ROE for Kentucky Power. Ultimately, the common equity that is required to support the utility operations of Kentucky Power must be raised in the capital markets, where investors consider the Company's ability to offer a rate of return that is competitive with other risk-comparable alternatives. The Company must compete with other investment opportunities and unless there is a reasonable expectation that investors will have the opportunity to earn returns commensurate with the underlying risks, capital will be allocated elsewhere, Kentucky Power's financial integrity will be weakened, and investors will demand an even higher rate of return. Kentucky Power's ability to offer a reasonable return on investment is a necessary ingredient in ensuring that customers continue to enjoy economical rates and reliable service.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF COMMON EQUITY FOR A UTILITY?

A. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Discounted Cash Flow Analyses

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The formula for the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where:
P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of common equity.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF COMMON EQUITY IN RATE CASES?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[19]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (*g*). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. WHAT FORM OF THE DCF MODEL DID YOU USE?

A. We applied the constant growth DCF model to estimate the cost of common equity for Kentucky Power, which is the form of the model most commonly relied

---

[19] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D1/P0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. HOW DID YOU DETERMINE THE DIVIDEND YIELD FOR THE ELECTRIC GROUP?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D1. This annual dividend was then divided by the corresponding 30-day average stock price at October 31, 2014 for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Electric Group are presented on page 1 of Exhibit WEA/AMM 6. As shown there, dividend yields for the firms in the Electric Group ranged from 2.6% to 4.6%.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. The next step is to evaluate long-term growth expectations, or “g”, for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only “g” that matters in applying the DCF model is the value that investors expect.

Q. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. Given that DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors, in the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors’ current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratios falling significantly. As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

A measure that plays a pivotal role in determining investors’ long-term growth expectations are future trends in earnings per share (“EPS”), which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS").

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. DID PROFESSOR MYRON J. GORDON, WHO ORIGINATED THE DCF APPROACH, RECOGNIZE THE PIVOTAL ROLE THAT EARNINGS PLAY IN FORMING INVESTORS' EXPECTATIONS?

A. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[20]

Q. ARE ANALYSTS' ASSESSMENTS OF GROWTH RATES APPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A. Yes. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets

[20] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications, as well as the continued success of services such as Thomson Reuters and Value Line, provides strong evidence that investors use them as a basis for their expectations.

While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. <u>The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations</u>.[21]

---

[21] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY PROXY GROUP?

A. The earnings growth projections for each of the firms in the Electric Group reported by Value Line, IBES, Zacks Investment Research ("Zacks"), and Reuters are displayed on page 2 of Exhibit WEA/AMM 6.[22]

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new

[22] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the Electric Group are summarized on page 2 of Exhibit WEA/AMM 6, with the underlying details being presented on Exhibit WEA/AMM 7.[23]

Q. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE "BR+SV" GROWTH RATE?

A. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[24]

The "sustainable growth" approach was included for completeness, but evidence indicates that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, we give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

---

[23] Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, which is consistent with the theory underlying this approach.

[24] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006).

Q. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE ELECTRIC GROUP USING THE DCF MODEL?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit WEA/AMM 6.

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. We based our evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[25] FERC recently affirmed that:

> The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt. In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test.[26]

Q. WHAT INTEREST RATE BENCHMARK DID YOU CONSIDER IN EVALUATING THE DCF RESULTS FOR KENTUCKY POWER?

A. As noted earlier, the S&P and Moody's ratings for Kentucky Power and the Electric Group are BBB+ and Baa1, respectively, which fall in the triple-B rating category. Accordingly, we referenced average yields on triple-B utilities bonds as one benchmark in evaluating low-end DCF results. Monthly yields on triple-B

---

[25] *See, e.g., Southern California Edison Co.,* 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").
[26] *Martha Coakley et al., v. Bangor Hydro-Electric Company, et al.,* Opinion No. 531, 147 FERC ¶ 61,234 at P 122 (2014).

bonds reported by Moody's averaged approximately 4.7% over the six months ended October 2014.[27]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth. As shown in Table 3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of approximately 6.8% over the period 2015-2019:

TABLE 3
IMPLIED BBB BOND YIELD

	2015-19
Projected AA Utility Yield	
IHS Global Insight (a)	6.32%
EIA (b)	6.08%
Average	6.20%
Current BBB - AA Yield Spread (c)	0.57%
Implied Triple-B Utility Yield	**6.77%**

(a) IHS Global Insight, U.S. Economic Outlook at 79 (May 2014)
(b) Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period May 2014 - Oct. 2014

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely referenced Blue Chip Financial Forecasts, which projects

[27] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

that yields on corporate bonds will climb on the order of 200 basis points through 2019.[28]

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE ELECTRIC GROUP?

A. Adding FERC's 100 basis-point premium to the historical and projected average utility bond yields implies a low-end threshold on the order of 5.7% to 7.8%. As highlighted on page 3 of Exhibit WEA/AMM 6, after considering this test and the distribution of individual estimates, we eliminated low-end DCF estimates ranging from -0.4% to 7.4%. Based on our professional experience and the risk-return principle that is fundamental to finance, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. As a result, consistent with the threshold established by historical and projected utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. IS THERE ANY JUSTIFICATION TO ELIMINATE HIGH-END DCF VALUES FOR THE ELECTRIC GROUP?

A. No. As shown on page 3 of Exhibit WEA/AMM 6, the upper end of the cost of equity range produced by the DCF analysis for the firms in the Electric Group is represented by cost of equity estimates of 13.0%. While these cost of equity estimates may exceed expectations for most electric utilities, low-end estimates on the order of 7.8% are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these

---

[28] *Blue Chip Financial Forecasts*, Vol. 33, No. 6 (Jun. 1, 2014).

values provide a reasonable basis on which to evaluate investors' required rate of return. In addition, these high-end values fall below the threshold for high-end outliers that has been consistently adopted by FERC, which has determined that DCF cost of equity estimates above 17.7 percent are "extreme," and that including such results would "skew the results."[29]

Q. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE ELECTRIC GROUP?

A. As shown on page 3 of Exhibit WEA/AMM 6 and summarized in Table 4, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following average cost of common equity estimates:

TABLE 4
DCF RESULTS – UTILITY PROXY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	9.5%	10.6%
IBES	10.0%	10.8%
Zacks	9.4%	10.1%
Reuters	10.1%	10.8%
br + sv	8.6%	8.9%

C. Empirical Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE ECAPM.

A. The ECAPM is a variant of the traditional CAPM, which is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are

[29] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004). FERC has continued to utilize this benchmark in evaluating DCF estimates at the upper end of the range. *See, e.g., S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57; *S. Cal. Edison Co.*, 139 FERC ¶ 61,042, at PP 54, 60; *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at PP 68-73; *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at PP 46, 52-54)..

fully diversified, the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

Where: R_j = Required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the ECAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the ECAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. WHY IS THE ECAPM APPROACH AN APPROPRIATE COMPONENT IN EVALUATING THE COST OF EQUITY FOR THE COMPANY?

A. The CAPM approach, which forms the foundation of the ECAPM, generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere,[30] the ECAPM provides important insight into investors' required rate of return for utility stocks, including Kentucky Power.

Q. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A. Myriad empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This empirical finding is widely reported in the finance literature, as summarized in New Regulatory Finance:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[31]

As discussed in *New Regulatory Finance*, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

---

[30] *See, e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," *Financial Practice and Education* (1998).

[31] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).

This ECAPM equation, and the associated weighting factors, recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and correct for the understated returns that would otherwise be produced for low beta stocks.

Q. HOW DID YOU APPLY THE ECAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A. Application of the ECAPM to the Electric Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit WEA/AMM 8. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the 408 dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the average of the EPS growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 408 individual firms, current estimates imply an average growth rate over the next five years of 10.8%. Combining this average growth rate with a year-ahead dividend yield of 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 13.1%. Subtracting a 3.3% risk-free rate based on the average yield on 30-year Treasury bonds for the six months ended October 2014 produced a market equity risk premium of 9.8%.

Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE ECAPM?

A. As indicated earlier, we relied on the beta values reported by Value Line, which in our experience is the most widely referenced source for beta in regulatory proceedings.

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE ECAPM?

A. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[32]

Because financial research indicates that the ECAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the ECAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical ECAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the ECAPM

---

[32] *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at p. 85.

cost of equity.[33] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of approximately 6.0% for a company in the first decile (market capitalization less than $338.8 million), to a reduction of 33 basis points for firms in the tenth decile (market capitalization between $21.8 billion and $428.7 billion). Accordingly, our ECAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Electric Group.

Q. WHAT COST OF EQUITY IS IMPLIED FOR THE ELECTRIC GROUP USING THE ECAPM APPROACH?

A. As shown on page 1 of Exhibit WEA/AMM 8, a forward-looking application of the ECAPM approach resulted in an average unadjusted ROE estimate of 11.3%. After adjusting for the impact of firm size, the ECAPM approach implied an average cost of equity of 12.2% for the Electric Group.[34]

Q. DID YOU ALSO APPLY THE ECAPM USING FORECASTED BOND YIELDS?

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. Accordingly, in addition to the use of current bond yields, we also applied the ECAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip. As shown on page 2 of Exhibit WEA/AMM 8, incorporating a forecasted Treasury bond yield for

---

[33] *Id.* at Table C-1.

[34] The midpoints of the unadjusted and size adjusted ECAPM ranges were 11.4% and 12.2%, respectively.

2015-2019 implied a cost of equity of approximately 11.6% for the Electric Group, or 12.4% after adjusting for the impact of relative size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 11.7% and 12.4%, respectively.

D. Utility Risk Premium

Q. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a fair ROE for Kentucky Power.

Q. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A. Estimates of equity risk premiums for utilities were based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR KENTUCKY POWER?

A. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (e.g., stock prices dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its Regulatory Focus report. In Exhibit WEA/AMM 9, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2013.[35] As shown on page 3 of Exhibit WEA/AMM 9, over this period, these equity risk premiums for electric utilities averaged 3.53%, and the yield on public utility bonds averaged 8.69%.

Q. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates.[36] In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity will rise or fall by a lesser amount. Therefore, when implementing the risk premium method, an adjustment is required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

---

[35] My analysis encompasses the entire period for which published data is available.

[36] *See, e.g.*, Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

Q. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater.[37] This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. For example, New Regulatory Finance documented this inverse relationship:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[38]

Other regulators have also recognized that the cost of equity does not move in tandem with interest rates.[39]

Q. WHAT ARE THE IMPLICATIONS OF THIS RELATIONSHIP UNDER CURRENT CAPITAL MARKET CONDITIONS?

A. As noted earlier, bond yields are at unprecedented lows. Given that equity risk premiums move inversely with interest rates, these uncharacteristically low bond yields also imply a sharp increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility

---

[37] *Id.*

[38] Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, at 128 (2006).

[39] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf; *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED ROES?

A. Because risk premiums move inversely with interest rates and current bond yields are significantly lower than the average over the study period, it is necessary to adjust the average equity risk premium over the study period to reflect the impact of changes in bond yields. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit WEA/AMM 9, the equity risk premium for electric utilities increased approximately 42 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit WEA/AMM 9, with an average yield on public utility bonds for the six-months ending October 2014 of 4.34%, this implied a current equity risk premium of 5.38% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 4.70% implies a current cost of equity of 10.08%.

Q. WHAT RISK PREMIUM COST OF EQUITY ESTIMATE WAS PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A. As shown on page 2 of Exhibit WEA/AMM 9, incorporating a forecasted yield for 2015-2019 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.50% for electric utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2015-2019 of 6.77% resulted in an implied cost of equity of 11.27%.

E. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the net amount of funds a utility receives when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q. IS THERE A THEORETICAL AND PRACTICAL BASIS TO INCLUDE A FLOTATION COST ADJUSTMENT IN THIS CASE?

A. Yes. First, an adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues has been recognized in the financial literature. In a Public Utilities Fortnightly article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[40] Similarly, New Regulatory Finance contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained

[40] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

> freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[41]

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. There are a number of ways in which a flotation cost adjustment can be calculated, but the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, Regulatory Finance: Utilities' Cost of Capital concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[42]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[43] Because Kentucky Power does not issue publicly traded common stock it does not incur flotation costs directly; however, issuance costs associated with AEP's 2009 public offering of common stock were equal to approximately 3.02% of the gross proceeds.[44] Multiplying a representative

---

[41] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.

[42] Roger A. Morin, "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc. at 166* (1994).

[43] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[44] American Electric Power Company, Inc., *Prospectus Supplement (To Prospectus dated December 22, 2008)* (Apr. 1, 2009). Net proceeds from AEP's sale of 69 million shares of common stock raised approximately $1.64 billion of additional equity capital.

dividend yield of 3.9% by this 3.02% expense percentage for AEP implies a minimum flotation cost adjustment on the order of 12 basis points.

VI. OTHER ROE BENCHMARKS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section presents alternative tests to demonstrate that the end-results of the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE given the facts and circumstances of Kentucky Power. The first test is based on applications of the traditional CAPM analysis using current and projected interest rates. The second test is based on expected earned returns for electric utilities. Finally, we present a DCF analysis for a select, low risk group of non-utility firms, with which the Company must compete for investors' money.

A. Capital Asset Pricing Model

Q. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY THE TRADITIONAL CAPM?

A. Our application of the traditional CAPM was based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the ECAPM. As shown on page 1 of Exhibit WEA/AMM 10, applying the forward-looking CAPM approach to the firms in the Electric Group results in an average theoretical cost of equity estimate of 10.7%, or 11.6% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.

As shown on page 2 of Exhibit WEA/AMM 10, incorporating a forecasted Treasury bond yield for 2015-2019 implied a cost of equity of approximately 11.1% for the Electric Group, or 11.9 % after adjusting for the impact of relative size.

B. Expected Earnings Approach

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF COMMON EQUITY?

A. As noted earlier, we also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in Bluefield and Hope. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation. The expected earnings approach is consistent with the economic rationale underpinning established regulatory standards, which specifies a methodology to determine an ROE benchmark based on earned rates of return for a peer group of other utilities.

Q. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (e.g., Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices- both of which are outside their direct control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is directly analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A. Value Line's projections imply an average rate of return on common equity for the electric utility industry of 10.6% over its forecast horizon.[45] Meanwhile, for the firms in the Electric Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit WEA/AMM 11. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit WEA/AMM 7. As shown on Exhibit No. 11, Value Line's projections for the

[45] The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014). Value Line reports return on year-end equity so the equivalent return on average equity would be higher.

Electric Group suggest an average ROE of approximately 9.9%, with a midpoint value of 10.8%.

C. Low Risk Non-Utility DCF

Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR KENTUCKY POWER?

A. Consistent with underlying economic and regulatory standards, we also applied the DCF model to a reference group of low-risk companies in the non-utility sectors of the economy. We refer to this group as the "Non-Utility Group".

A. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?

A. Yes. The cost of equity capital in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The Bluefield case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the Hope case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[46]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from many industries, it

---

[46] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A. The comparable risk proxy group was composed of those United States companies followed by Value Line that:

1) pay common dividends;
2) have a Safety Rank of “1”;
3) have a Financial Strength Rating of “B++” or greater;
4) have a beta of 0.70 or less; and
5) have investment grade credit ratings from S&P.[47]

Q. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE ELECTRIC GROUP?

A. Table 5 compares the Non-Utility Group with the Electric Group and Kentucky Power across the risk measures discussed earlier:

---

[47] Credit rating firms, such as S&P, use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'AAA', 'AA', 'A', and 'BBB' ratings are considered investment grade. Credit ratings for bonds below these designations ('BB', 'B', 'CCC', etc.) are considered speculative grade, and are commonly referred to as "junk bonds". The term “investment grade” refers to bonds with ratings in the ‘BBB’ category and above.

TABLE 5
COMPARISON OF RISK INDICATORS

			Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility	A	A2	1	A+	0.66
Electric Group	BBB	Baa2	2	B++	0.76
Kentucky Power	BBB	Baa2	2	A	0.70

As shown above, the average credit ratings, Safety Rank, Financial Strength Rating, and beta for the Non-Utility Group suggest less risk than for Kentucky Power and the proxy group of electric utilities. When considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the Electric Group and the Company are greater than those of the firms in the Non-Utility Group.

The sixteen companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Colgate-Palmolive, McDonalds, Proctor & Gamble, and Wal-Mart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group approaching 3%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A. We applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Electric Group, with the results being presented in Exhibit WEA/AMM 12. As summarized in Table 6, below, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 6
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.9%	10.9%
IBES	10.5%	10.4%
Zacks	10.4%	10.7%
Reuters	10.6%	11.1%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. HOW CAN YOU RECONCILE THESE DCF RESULTS FOR THE NON-UTILITY GROUP AGAINST THE SIGNIFICANTLY LOWER ESTIMATES PRODUCED FOR YOUR GROUP OF UTILITIES?

A. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As documented earlier, the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings, Value Line's Safety Rank, Financial Strength, and beta – are lower than the risks investors associate with the Electric Group and Kentucky Power. The objective evidence provided by these observable risk measures rules out a conclusion that the higher non-utility DCF estimates are associated with higher investment risk.

Rather, the divergence between the DCF results for these groups of utility and non-utility firms can be attributed to the fact that DCF estimates invariably depart from the returns that investors actually require because their expectations may not be captured by the inputs to the model, particularly the assumed growth rate. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for the Company. There is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector, and the divergence between the DCF estimates for the group of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result. The DCF results for the Non-Utility Group, which ranged from 10.4% to 10.9% and averaged 10.6%, provide additional confirmation that a 10.5% ROE for Kentucky Power before flotation costs is a reasonable estimate of investors' required return.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ALTERNATIVE ROE BENCHMARKS.

A. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 2 of Exhibit WEA/AMM 3, and summarized in Table 7, below:

TABLE 7
SUMMARY OF ALTERNATIVE ROE BENCHMARKS

	Average	Midpoint
CAPM - Historical Bond Yield		
Unadjusted	10.7%	10.9%
Size Adjusted	11.6%	11.6%
CAPM - Projected Bond Yield		
Unadjusted	11.1%	11.2%
Size Adjusted	11.9%	11.9%
Expected Earnings		
Industry	10.6%	
Proxy Group	9.9%	10.8%
Non-Utility DCF		
Value Line	10.9%	10.9%
IBES	10.5%	10.4%
Zacks	10.4%	10.7%
Reuters	10.6%	11.1%

The results of these alternative benchmarks confirm our conclusion that an ROE of 10.62% for Kentucky Power's electric utility operations is reasonable.

Q. WHAT IS YOUR OPINION CONCERNING A REASONABLE RETURN ON ENVIRONMENTAL COMPLIANCE-RELATED CAPITAL EXPENDITURES FOR USE IN CONNECTION WITH THE COMPANY'S ENVIRONMENTAL COST-RECOVERY SURCHARGE?

A. For the reasons I discuss above, 10.62% is a fair, just, and reasonable return on equity in connection with Kentucky Power's environmental compliance-related expenditures.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

QUALIFICATIONS OF WILLIAM E. AVERA

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes Dr. Avera's background and experience and contains the details of his qualifications.

Q. DR. AVERA, PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation

Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance, The University of Texas at Austin (Sep. 1979 to May 1981) Assistant Professor of Finance, (Sep. 1975 to May 1977)	Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.
Assistant Professor of Business, University of North Carolina at Chapel Hill (Sep. 1972 to Jul. 1975)	Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance, University of North Carolina at Chapel Hill (Jan. 1969 to Aug. 1972)	Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics. Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*
B.A., *Economics*, Emory University, Atlanta, Georgia (Sep. 1961 to Jun. 1965)	Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in almost 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Co-chair, Synchronous Interconnection Committee established by Texas Legislature to study interconnection of Texas with national grid; Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA

Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Treasurer, Dripping Springs Presbyterian Church; Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

“Economic Perspectives on Texas Water Resources,” with Robert M. Avera and Felipe Chacon in *Essentials of Texas Water Resources*, Mary K. Sahs, ed. State Bar of Texas (2012).

Ethics and the Investment Professional (video, workbook, and instructor’s guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

“Definition of Industry Ethics and Development of a Code” and “Applying Ethics in the Real World,” in *Good Ethics: The Essential Element of a Firm’s Success*, Association for Investment Management and Research (1994)

“On the Use of Security Analysts’ Growth Projections in the DCF Model,” with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

“Usefulness of Current Values to Investors and Creditors,” *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

“The Geometric Mean Strategy and Common Stock Investment Management,” with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky

Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes Mr. McKenzie's background and experience and contains the details of his qualifications.

Q. MR. MCKENZIE, PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony concerning the rate of return on equity ("ROE") in proceedings filed with FERC, the Kansas State Corporation Commission, Kentucky Public Service Commission, Montana Public Service Commission, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair ROE for regulated electric and gas utility operations. In addition, I have previously prepared prefiled direct and rebuttal testimony in over 250 regulatory proceedings before FERC, the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states. This testimony was sponsored by Dr. William E. Avera, who is President of FINCAP, Inc. In connection with these assignments, my responsibilities have included performing analytical methods to estimate investors' required rate of return and critically evaluating the results of alternative approaches, preparing direct testimony, responding to data requests, evaluating the positions of other parties and preparing responsive testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs. Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I earned B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation.

ADRIEN M. McKENZIE

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap3@texas.net

Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA) designation. He has over 25 years experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

Consultant, FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC,* Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014)

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012)

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in 33 states, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of ROE. Many of these proceedings have been influential in addressing key aspects of FERC's policies with respect to ROE determinations. Broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

ROE ANALYSES

SUMMARY OF RESULTS

	Average	Midpoint
DCF		
Value Line	9.5%	10.6%
IBES	10.0%	10.8%
Zacks	9.4%	10.1%
Reuters	10.1%	10.8%
Internal br + sv	8.6%	8.9%
Empirical CAPM - Historical Bond Yield		
Unadjusted	11.3%	11.4%
Size Adjusted	12.2%	12.2%
Empirical CAPM - Projected Bond Yield		
Unadjusted	11.6%	11.7%
Size Adjusted	12.4%	12.4%
Utility Risk Premium		
Historical Bond Yields	10.1%	
Projected Bond Yields	11.3%	

Cost of Equity Recommendation	
Cost of Equity Range	9.7% -- 11.3%
Recommended Point Estimate	10.50%
Flotation Cost Adjustment	
Dividend Yield	3.9%
Flotation Cost Percentage	3.0%
Adjustment	0.12%
ROE Recommendation	**10.62%**

ROE ANALYSES

CHECKS OF REASONABLENESS

	Average	Midpoint
CAPM - Historical Bond Yield		
Unadjusted	10.7%	10.9%
Size Adjusted	11.6%	11.6%
CAPM - Projected Bond Yield		
Unadjusted	11.1%	11.2%
Size Adjusted	11.9%	11.9%
Expected Earnings		
Industry	10.6%	
Proxy Group	9.9%	10.8%
Non-Utility DCF		
Value Line	10.9%	10.9%
IBES	10.5%	10.4%
Zacks	10.4%	10.7%
Reuters	10.3%	11.1%

REGULATORY MECHANISMS

ELECTRIC GROUP

	Company (a)	Mechanism
1	Ameren Corp.	FCA, PGA, ICR, DSM, ECA, BDR
2	American Elec Pwr	FCA, ICR, ECA
3	Black Hills Corp.	FCA, PGA, ICR; ECA, TCR, WNA, Construction financing rider to recover financing costs in lieu of AFUDC
4	CMS Energy Corp.	FCA, PGA, RDM
5	Entergy Corp.	FCA; PGA; SCR; DSM; Pre-Approval rider for generating facility
6	FirstEnergy Corp.	DSM; ICR; TCR
7	Great Plains Energy	FCA in Kansas (no FCA in Missouri); PCR
8	Hawaiian Elec.	FCA, RDM
9	IDACORP, Inc.	FCA, RDM (Fixed Cost Adjustment Mechanism), DSM
10	PG&E Corp.	FCA, RDM
11	SCANA Corp.	FCA, PGA, RDM, ICR, DSM, PCR, SCR
12	Sempra Energy	FCA, RDM
13	Westar Energy	FCA, ECA, PCR

(a) Excludes American Electric Power Company, Inc.

BDR -- Bad Debt Cost Recovery Rider
DSM -- Demand Side Management / Conservation Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
FCA -- Fuel and/or Power Cost Adjustment Clause
FTY - Jurisdiction allows for future test year
ICR -- Infrastructure Investment / Renewables Cost Recovery Mechanism
PCR -- Pension Cost Recovery Mechanism
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
SCR - Storm Cost Recovery Tracker
TCR -- Transmission Cost Recovery Tracker
WNC -- Weather Normalization Clause or other mitigants

Source : 2013 Form 10-K Reports

CAPITAL STRUCTURE

ELECTRIC GROUP

		At Fiscal Year-End 2013 (a)			Value Line Projected (b)		
	Company	**Debt**	**Preferred**	**Common Equity**	**Debt**	**Other**	**Common Equity**
1	Ameren Corp.	47.5%	0.0%	52.5%	45.5%	1.0%	53.5%
2	American Elec Pwr	49.0%	0.0%	51.0%	52.0%	0.0%	48.0%
3	Black Hills Corp.	51.6%	0.0%	48.4%	53.5%	0.0%	46.5%
4	CMS Energy Corp.	68.7%	0.0%	31.3%	62.5%	0.5%	37.0%
5	Entergy Corp.	54.1%	1.4%	44.5%	54.5%	1.0%	44.5%
6	FirstEnergy Corp.	57.6%	0.0%	42.4%	55.0%	0.0%	45.0%
7	Great Plains Energy	50.0%	0.6%	49.4%	43.5%	0.5%	56.0%
8	Hawaiian Elec.	46.4%	0.0%	53.6%	50.0%	0.5%	49.5%
9	IDACORP, Inc.	43.5%	6.6%	49.9%	48.5%	0.0%	51.5%
10	PG&E Corp.	48.2%	0.9%	50.9%	48.5%	0.5%	51.0%
11	SCANA Corp.	53.9%	0.0%	46.1%	52.5%	0.0%	47.5%
12	Sempra Energy	51.1%	0.1%	48.8%	52.0%	0.0%	48.0%
13	Westar Energy	51.4%	0.0%	48.6%	50.0%	0.0%	50.0%
	Average	**51.8%**	**0.7%**	**47.5%**	**51.4%**	**0.3%**	**48.3%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014).

DCF MODEL - ELECTRIC GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Ameren Corp.	$ 39.78	$ 1.64	4.1%
2	American Elec Pwr	$ 54.29	$ 2.12	3.9%
3	Black Hills Corp.	$ 49.95	$ 1.62	3.2%
4	CMS Energy Corp.	$ 30.73	$ 1.13	3.7%
5	Entergy Corp.	$ 79.19	$ 3.32	4.2%
6	FirstEnergy Corp.	$ 34.88	$ 1.44	4.1%
7	Great Plains Energy	$ 25.17	$ 0.96	3.8%
8	Hawaiian Elec.	$ 26.99	$ 1.24	4.6%
9	IDACORP, Inc.	$ 56.77	$ 1.88	3.3%
10	PG&E Corp.	$ 45.81	$ 1.82	4.0%
11	SCANA Corp.	$ 50.85	$ 2.15	4.2%
12	Sempra Energy	$105.56	$ 2.76	2.6%
13	Westar Energy	$ 35.40	$ 1.40	4.0%
	Average			**3.8%**

(a) Average of closing prices for 30 trading days ended Oct. 31, 2014.

(b) The Value Line Investment Survey, Summary & Index (Oct. 31, 2014).

DCF MODEL - ELECTRIC GROUP

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)
		Earnings Growth				br+sv
	Company	V Line	IBES	Zacks	Reuters	Growth
1	Ameren Corp.	4.5%	8.9%	8.3%	8.9%	4.0%
2	American Elec Pwr	4.5%	5.0%	4.9%	5.0%	3.9%
3	Black Hills Corp.	9.5%	7.0%	NA	NA	4.1%
4	CMS Energy Corp.	6.5%	6.8%	6.1%	6.8%	6.3%
5	Entergy Corp.	1.0%	1.7%	-1.1%	1.7%	4.2%
6	FirstEnergy Corp.	4.5%	-0.5%	-4.5%	-3.3%	3.9%
7	Great Plains Energy	6.0%	5.0%	5.0%	5.0%	3.1%
8	Hawaiian Elec.	4.0%	4.0%	4.0%	4.0%	3.9%
9	IDACORP, Inc.	1.5%	4.0%	4.0%	NA	3.6%
10	PG&E Corp.	5.0%	7.0%	5.6%	8.2%	3.0%
11	SCANA Corp.	5.0%	4.6%	4.4%	4.6%	5.0%
12	Sempra Energy	7.0%	7.5%	7.5%	7.5%	6.1%
13	Westar Energy	6.0%	3.2%	3.8%	3.2%	4.9%

(a) The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014).
(b) www.finance.yahoo.com (retrieved Oct. 31, 2014).
(c) www.zacks.com (retrieved Oct. 31, 2014).
(d) www.reuters.com/finance/stocks (retrieved Oct. 31, 2014).
(e) See Exhibit No. 7.

DCF MODEL - ELECTRIC GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)
		Cost of Equity Estimates				br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Reuters**	**Growth**
1	Ameren Corp.	8.6%	13.0%	12.4%	13.0%	8.1%
2	American Elec Pwr	8.4%	8.9%	8.8%	8.9%	7.8%
3	Black Hills Corp.	12.7%	10.2%	NA	NA	7.4%
4	CMS Energy Corp.	10.2%	10.5%	9.8%	10.5%	10.0%
5	Entergy Corp.	5.2%	5.9%	3.1%	5.8%	8.4%
6	FirstEnergy Corp.	8.6%	3.6%	-0.4%	0.8%	8.1%
7	Great Plains Energy	9.8%	8.8%	8.8%	8.8%	6.9%
8	Hawaiian Elec.	8.6%	8.6%	8.6%	8.6%	8.5%
9	IDACORP, Inc.	4.8%	7.3%	7.3%	NA	6.9%
10	PG&E Corp.	9.0%	10.9%	9.6%	12.2%	6.9%
11	SCANA Corp.	9.2%	8.8%	8.6%	8.8%	9.2%
12	Sempra Energy	9.6%	10.1%	10.1%	10.1%	8.7%
13	Westar Energy	10.0%	7.2%	7.8%	7.2%	8.8%
	Average (b)	**9.5%**	**10.0%**	**9.4%**	**10.1%**	**8.6%**
	Midpoint (c)	**10.6%**	**10.8%**	**10.1%**	**10.8%**	**8.9%**

(a) Sum of dividend yield (Exhibit No. 6, p. 1) and respective growth rate (Exhibit No. 6, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - ELECTRIC GROUP

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2018					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Ameren Corp.	$3.00	$1.80	$32.00	40.0%	9.4%	1.0210	9.6%	3.8%	0.0095	0.2000	0.19%	**4.0%**
2	American Elec Pwr	$4.00	$2.50	$40.50	37.5%	9.9%	1.0223	10.1%	3.8%	0.0056	0.2636	0.15%	**3.9%**
3	Black Hills Corp.	$3.25	$1.90	$35.50	41.5%	9.2%	1.0218	9.4%	3.9%	0.0078	0.2900	0.23%	**4.1%**
4	CMS Energy Corp.	$2.25	$1.35	$17.25	40.0%	13.0%	1.0338	13.5%	5.4%	0.0215	0.4250	0.92%	**6.3%**
5	Entergy Corp.	$6.50	$3.80	$66.75	41.5%	9.7%	1.0220	10.0%	4.1%	0.0016	0.2147	0.03%	**4.2%**
6	FirstEnergy Corp.	$3.00	$1.60	$36.50	46.7%	8.2%	1.0213	8.4%	3.9%	0.0060	0.0267	0.02%	**3.9%**
7	Great Plains Energy	$2.00	$1.20	$26.00	40.0%	7.7%	1.0160	7.8%	3.1%	0.0033	(0.0400)	-0.01%	**3.1%**
8	Hawaiian Elec.	$2.00	$1.30	$20.50	35.0%	9.8%	1.0275	10.0%	3.5%	0.0226	0.1800	0.41%	**3.9%**
9	IDACORP, Inc.	$3.75	$2.20	$44.90	41.3%	8.4%	1.0206	8.5%	3.5%	0.0045	0.1448	0.06%	**3.6%**
10	PG&E Corp.	$3.00	$2.10	$36.50	30.0%	8.2%	1.0242	8.4%	2.5%	0.0226	0.1889	0.43%	**3.0%**
11	SCANA Corp.	$4.25	$2.35	$43.50	44.7%	9.8%	1.0380	10.1%	4.5%	0.0270	0.1714	0.46%	**5.0%**
12	Sempra Energy	$6.50	$3.40	$56.25	47.7%	11.6%	1.0248	11.8%	5.6%	0.0106	0.4231	0.45%	**6.1%**
13	Westar Energy	$2.90	$1.60	$29.65	44.8%	9.8%	1.0266	10.0%	4.5%	0.0139	0.2588	0.36%	**4.9%**

DCF MODEL - ELECTRIC GROUP

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2013			2018			Chg	2018 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2013	2018	Growth
1	Ameren Corp.	53.7%	$12,190	$6,546	53.5%	$15,100	$8,079	4.3%	$45.00	$35.00	$40.00	1.250	242.63	252.00	0.76%
2	American Elec Pwr	48.9%	$32,913	$16,094	48.0%	$41,900	$20,112	4.6%	$65.00	$45.00	$55.00	1.358	487.78	498.00	0.42%
3	Black Hills Corp.	48.4%	$2,705	$1,309	46.5%	$3,500	$1,628	4.5%	$60.00	$40.00	$50.00	1.408	44.50	45.75	0.56%
4	CMS Energy Corp.	32.2%	$10,730	$3,455	37.0%	$13,100	$4,847	7.0%	$35.00	$25.00	$30.00	1.739	266.10	283.00	1.24%
5	Entergy Corp.	43.6%	$22,109	$9,640	44.5%	$27,000	$12,015	4.5%	$100.00	$70.00	$85.00	1.273	178.37	179.50	0.13%
6	FirstEnergy Corp.	44.5%	$28,523	$12,693	45.0%	$34,900	$15,705	4.4%	$45.00	$30.00	$37.50	1.027	418.63	431.00	0.58%
7	Great Plains Energy	49.4%	$7,029	$3,472	56.0%	$7,275	$4,074	3.2%	$30.00	$20.00	$25.00	0.962	153.87	156.50	0.34%
8	Hawaiian Elec.	55.0%	$3,143	$1,729	49.5%	$4,600	$2,277	5.7%	$30.00	$20.00	$25.00	1.220	101.26	111.00	1.85%
9	IDACORP, Inc.	53.4%	$3,466	$1,851	51.5%	$4,415	$2,274	4.2%	$60.00	$45.00	$52.50	1.169	50.23	51.20	0.38%
10	PG&E Corp.	52.5%	$27,311	$14,338	51.0%	$35,800	$18,258	5.0%	$55.00	$35.00	$45.00	1.233	456.67	500.00	1.83%
11	SCANA Corp.	46.4%	$10,059	$4,667	47.5%	$14,375	$6,828	7.9%	$60.00	$45.00	$52.50	1.207	141.00	157.50	2.24%
12	Sempra Energy	49.4%	$22,281	$11,007	48.0%	$29,400	$14,112	5.1%	$110.00	$85.00	$97.50	1.733	244.46	252.00	0.61%
13	Westar Energy	50.0%	$6,131	$3,066	50.0%	$8,000	$4,000	5.5%	$45.00	$35.00	$40.00	1.349	128.25	135.00	1.03%

(a) The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2018 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2018 BVPS.

EMPIRICAL CAPM - CURRENT BOND YIELD

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				**Market**										**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**	**Unadjusted RP**		**Beta Adjusted RP**			**Total**	**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*** [1]	**Beta**	**Weight**	***RP*** [2]	**RP**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Ameren Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.75	75%	5.5%	8.0%	11.3%	$ 10,329.9	0.80%	12.1%
2	American Elec Pwr	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.70	75%	5.1%	7.6%	10.9%	$ 28,507.2	-0.33%	10.6%
3	Black Hills Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.90	75%	6.6%	9.1%	12.4%	$ 2,437.4	1.72%	14.1%
4	CMS Energy Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.75	75%	5.5%	8.0%	11.3%	$ 9,015.0	0.93%	12.2%
5	Entergy Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.70	75%	5.1%	7.6%	10.9%	$ 15,125.6	0.80%	11.7%
6	FirstEnergy Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.70	75%	5.1%	7.6%	10.9%	$ 15,764.4	0.80%	11.7%
7	Great Plains Energy	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.85	75%	6.2%	8.7%	12.0%	$ 4,135.3	1.19%	13.2%
8	Hawaiian Elec.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.80	75%	5.9%	8.3%	11.6%	$ 2,846.7	1.72%	13.4%
9	IDACORP, Inc.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.80	75%	5.9%	8.3%	11.6%	$ 3,176.4	1.72%	13.4%
10	PG&E Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.65	75%	4.8%	7.2%	10.5%	$ 23,655.5	-0.33%	10.2%
11	SCANA Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.75	75%	5.5%	8.0%	11.3%	$ 7,702.6	0.93%	12.2%
12	Sempra Energy	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.75	75%	5.5%	8.0%	11.3%	$ 27,146.1	-0.33%	10.9%
13	Westar Energy	2.3%	10.8%	13.1%	3.3%	9.8%	25%	2.5%	0.75	75%	5.5%	8.0%	11.3%	$ 4,869.7	1.19%	12.5%
	Average												**11.3%**			**12.2%**
	Midpoint (h)												**11.4%**			**12.2%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Sep. 19, 201
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Sep. 22, 2014).
(c) Average yield on 30-year Treasury bonds for the six-months ending Oct. 2014 based on data from the http://www.federalreserve.gov/releases/h15/data.ht
(d) Morin, Roger A., "New Regulatory Finance,"*Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014)
(f) www.valueline.com (retrieved Nov. 5, 2014)
(g) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(h) Average of low and high values

EMPIRICAL CAPM - PROJECTED BOND YIELD

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP¹***	**Beta**	**Weight**	***RP²***	**RP**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Ameren Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 10,329.9	0.80%	12.3%
2	American Elec Pwr	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.70	75%	4.4%	6.5%	11.2%	$ 28,507.2	-0.33%	10.9%
3	Black Hills Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.90	75%	5.7%	7.8%	12.5%	$ 2,437.4	1.72%	14.2%
4	CMS Energy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 9,015.0	0.93%	12.5%
5	Entergy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.70	75%	4.4%	6.5%	11.2%	$ 15,125.6	0.80%	12.0%
6	FirstEnergy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.70	75%	4.4%	6.5%	11.2%	$ 15,764.4	0.80%	12.0%
7	Great Plains Energy	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.85	75%	5.4%	7.5%	12.2%	$ 4,135.3	1.19%	13.3%
8	Hawaiian Elec.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.80	75%	5.0%	7.1%	11.8%	$ 2,846.7	1.72%	13.6%
9	IDACORP, Inc.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.80	75%	5.0%	7.1%	11.8%	$ 3,176.4	1.72%	13.6%
10	PG&E Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.65	75%	4.1%	6.2%	10.9%	$ 23,655.5	-0.33%	10.6%
11	SCANA Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 7,702.6	0.93%	12.5%
12	Sempra Energy	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 27,146.1	-0.33%	11.2%
13	Westar Energy	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 4,869.7	1.19%	12.7%
	Average												**11.6%**			**12.4%**
	Midpoint (h)												**11.7%**			**12.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Sep. 19, 201
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Sep. 22, 2014).
(c) Average yield on 30-year Treasury bonds for 2015-2019 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 22, 2014); IHS Global Insight, U.S. Econom Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 6 (Jun. 1, 2014).
(d) Morin, Roger A., "New Regulatory Finance,"*Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014)
(f) www.valueline.com (retrieved Nov. 5, 2014)
(g) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(h) Average of low and high values

ELECTRIC UTILITY RISK PREMIUM

CURRENT BOND YIELD

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Average Utility Bond Yield	4.34%
	Change in Bond Yield	-4.35%
(c)	Risk Premium/Interest Rate Relationship	-0.4246
	Adjustment to Average Risk Premium	1.85%
(a)	Average Risk Premium over Study Period	3.53%
	Adjusted Risk Premium	**5.38%**

Implied Cost of Equity

(b)	BBB Utility Bond Yield	4.70%
	Adjusted Equity Risk Premium	5.38%
	Risk Premium Cost of Equity	**10.08%**

(a) Exhibit No. 9, page 3.
(b) Average bond yield for six-months ending Oct. 2014 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. 9, page 4.

ELECTRIC UTILITY RISK PREMIUM

PROJECTED BOND YIELD

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Average Utility Bond Yield 2015-2019	6.41%
	Change in Bond Yield	-2.28%
(c)	Risk Premium/Interest Rate Relationship	-0.4246
	Adjustment to Average Risk Premium	0.97%
(a)	Average Risk Premium over Study Period	3.53%
	Adjusted Risk Premium	**4.50%**

Implied Cost of Equity

(b)	BBB Utility Bond Yield 2015-2019	6.77%
	Adjusted Equity Risk Premium	4.50%
	Risk Premium Cost of Equity	**11.27%**

(a) Exhibit No. 9, page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014); & Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. 9, page 4.

ELECTRIC UTILITY RISK PREMIUM

AUTHORIZED RETURNS

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.36%	6.08%	4.28%
2007	10.36%	6.11%	4.25%
2008	10.46%	6.65%	3.81%
2009	10.48%	6.28%	4.20%
2010	10.34%	5.56%	4.78%
2011	10.29%	5.13%	5.16%
2012	10.17%	4.26%	5.91%
2013	10.02%	4.55%	5.47%
Average	12.21%	8.69%	3.53%

(a) Major Rate Case Decisions, Regulatory Focus, Regulatory Research Associates; *UtilityScope Regulatory Service*, Argus.

(b) Moody's Investors Service.

ELECTRIC UTILITY RISK PREMIUM

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9186517
R Square	0.8439209
Adjusted R Square	0.8398135
Standard Error	0.0051378
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005423795	0.005424	205.4662	6.5706E-17
Residual	38	0.001003105	2.64E-05		
Total	39	0.0064269			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0721319	0.002698047	26.73484	3.02E-26	0.06666996	0.07759379	0.066669963	0.077593786
X Variable 1	-0.4245597	0.02961887	-14.3341	6.57E-17	-0.48451992	-0.36459938	-0.48451992	-0.36459938

CAPM - CURRENT BOND YIELD

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	Ameren Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	0.75	10.7%	$ 10,329.9	0.80%	11.5%
2	American Elec Pwr	2.3%	10.8%	13.1%	3.3%	9.8%	0.70	10.2%	$ 28,507.2	-0.33%	9.8%
3	Black Hills Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	0.90	12.1%	$ 2,437.4	1.72%	13.8%
4	CMS Energy Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	0.75	10.7%	$ 9,015.0	0.93%	11.6%
5	Entergy Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	0.70	10.2%	$ 15,125.6	0.80%	11.0%
6	FirstEnergy Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	0.70	10.2%	$ 15,764.4	0.80%	11.0%
7	Great Plains Energy	2.3%	10.8%	13.1%	3.3%	9.8%	0.85	11.6%	$ 4,135.3	1.19%	12.8%
8	Hawaiian Elec.	2.3%	10.8%	13.1%	3.3%	9.8%	0.80	11.1%	$ 2,846.7	1.72%	12.9%
9	IDACORP, Inc.	2.3%	10.8%	13.1%	3.3%	9.8%	0.80	11.1%	$ 3,176.4	1.72%	12.9%
10	PG&E Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	0.65	9.7%	$ 23,655.5	-0.33%	9.3%
11	SCANA Corp.	2.3%	10.8%	13.1%	3.3%	9.8%	0.75	10.7%	$ 7,702.6	0.93%	11.6%
12	Sempra Energy	2.3%	10.8%	13.1%	3.3%	9.8%	0.75	10.7%	$ 27,146.1	-0.33%	10.3%
13	Westar Energy	2.3%	10.8%	13.1%	3.3%	9.8%	0.75	10.7%	$ 4,869.7	1.19%	11.8%
	Average							**10.7%**			**11.6%**
	Midpoint (g)							**10.9%**			**11.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Sep. 19, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Sep. 22, 2014).
(c) Average yield on 30-year Treasury bonds for the six-months ending Oct. 2014 based on data from the
(d) The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014).
(e) www.valueline.com (retrieved Nov. 5, 2014).
(f) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(g) Average of low and high values.

CAPM - PROJECTED BOND YIELD

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	Ameren Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 10,329.9	0.80%	11.8%
2	American Elec Pwr	2.3%	10.8%	13.1%	4.7%	8.4%	0.70	10.6%	$ 28,507.2	-0.33%	10.3%
3	Black Hills Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.90	12.3%	$ 2,437.4	1.72%	14.0%
4	CMS Energy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 9,015.0	0.93%	11.9%
5	Entergy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.70	10.6%	$ 15,125.6	0.80%	11.4%
6	FirstEnergy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.70	10.6%	$ 15,764.4	0.80%	11.4%
7	Great Plains Energy	2.3%	10.8%	13.1%	4.7%	8.4%	0.85	11.8%	$ 4,135.3	1.19%	13.0%
8	Hawaiian Elec.	2.3%	10.8%	13.1%	4.7%	8.4%	0.80	11.4%	$ 2,846.7	1.72%	13.1%
9	IDACORP, Inc.	2.3%	10.8%	13.1%	4.7%	8.4%	0.80	11.4%	$ 3,176.4	1.72%	13.1%
10	PG&E Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.65	10.2%	$ 23,655.5	-0.33%	9.8%
11	SCANA Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 7,702.6	0.93%	11.9%
12	Sempra Energy	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 27,146.1	-0.33%	10.7%
13	Westar Energy	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 4,869.7	1.19%	12.2%
	Average							**11.1%**			**11.9%**
	Midpoint (g)							**11.2%**			**11.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Sep. 19, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Sep. 22, 2014).
(c) Average yield on 30-year Treasury bonds for 2015-2019 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 22, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 6 (Jun. 1, 2014).
(d) The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014).
(e) www.valueline.com (retrieved Nov. 5, 2014).
(f) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(g) Average of low and high values.

EXPECTED EARNINGS APPROACH

ELECTRIC GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Ameren Corp.	9.5%	1.0210	9.7%
2	American Elec Pwr	10.0%	1.0223	10.2%
3	Black Hills Corp.	9.0%	1.0218	9.2%
4	CMS Energy Corp.	13.5%	1.0338	14.0%
5	Entergy Corp.	10.0%	1.0220	10.2%
6	FirstEnergy Corp.	8.5%	1.0213	8.7%
7	Great Plains Energy	7.5%	1.0160	7.6%
8	Hawaiian Elec.	10.0%	1.0275	10.3%
9	IDACORP, Inc.	8.5%	1.0206	8.7%
10	PG&E Corp.	8.5%	1.0242	8.7%
11	SCANA Corp.	10.0%	1.0380	10.4%
12	Sempra Energy	11.5%	1.0248	11.8%
13	Westar Energy	9.5%	1.0266	9.8%
	Average (d)			**9.9%**
	Midpoint (e)			**10.8%**

(a) The Value Line Investment Survey (Aug. 22, Sep. 19, & Oct. 31, 2014).

(b) Adjustment to convert year-end return to an average rate of return from Exhibit No. 7.

(c) (a) x (b).

(d) Excludes highlighted figures.

(e) Average of low and high values.

DCF MODEL - NON-UTILITY GROUP

DIVIDEND YIELD

			(a)	(b)	
	Company	**Industry Group**	**Price**	**Dividends**	**Yield**
1	Church & Dwight	Household Products	$ 70.12	$ 1.24	1.8%
2	Coca-Cola	Beverage	$ 42.42	$ 1.30	3.1%
3	Colgate-Palmolive	Household Products	$ 65.22	$ 1.50	2.3%
4	ConAgra Foods	Food Processing	$ 33.60	$ 1.00	3.0%
5	Gen'l Mills	Food Processing	$ 50.32	$ 1.66	3.3%
6	Hormel Foods	Food Processing	$ 51.55	$ 0.86	1.7%
7	Johnson & Johnson	Medical Supply	$ 103.52	$ 2.80	2.7%
8	Kellogg	Food Processing	$ 61.46	$ 1.96	3.2%
9	Kimberly-Clark	Household Products	$ 108.99	$ 3.36	3.1%
10	McCormick & Co.	Food Processing	$ 67.75	$ 1.60	2.4%
11	McDonald's Corp.	Restaurant	$ 92.83	$ 3.40	3.7%
12	PepsiCo, Inc.	Beverage	$ 93.56	$ 2.74	2.9%
13	Procter & Gamble	Household Products	$ 84.36	$ 2.58	3.1%
14	Smucker (J.M.)	Food Processing	$ 99.73	$ 2.59	2.6%
15	Verizon Communic.	Telecommunications	$ 49.24	$ 2.20	4.5%
16	Wal-Mart Stores	Retail Store	$ 76.45	$ 1.92	2.5%
	Average				**2.9%**

(a) Average of closing prices for 30 trading days ended Oct. 31, 2014.
(b) The Value Line Investment Survey, Summary & Index(Oct. 31, 2014).

DCF MODEL - NON-UTILITY GROUP

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth Rates			
	Company	V Line	IBES	Zacks	Reuters
1	Church & Dwight	9.5%	9.88%	9.93%	8.80%
2	Coca-Cola	6.5%	3.83%	6.22%	3.83%
3	Colgate-Palmolive	10.5%	8.50%	8.60%	8.00%
4	ConAgra Foods	8.0%	9.35%	8.23%	10.70%
5	Gen'l Mills	7.0%	6.50%	7.64%	6.00%
6	Hormel Foods	11.0%	11.00%	8.00%	NA
7	Johnson & Johnson	6.5%	6.55%	6.04%	6.63%
8	Kellogg	6.5%	5.80%	5.93%	4.20%
9	Kimberly-Clark	9.0%	6.70%	7.22%	6.70%
10	McCormick & Co.	8.0%	8.60%	7.97%	8.60%
11	McDonald's Corp.	7.0%	5.43%	7.26%	4.92%
12	PepsiCo, Inc.	8.5%	7.76%	7.88%	7.45%
13	Procter & Gamble	7.5%	8.30%	8.05%	8.30%
14	Smucker (J.M.)	8.0%	7.60%	7.13%	7.50%
15	Verizon Communic.	8.0%	7.18%	8.24%	8.35%
16	Wal-Mart Stores	6.5%	5.54%	6.75%	4.16%

(a) The Value Line Investment Survey (Aug, 22, Aug. 29, Sep. 19. Sep. 26, Oct. 24 & Oct. 31, 2014).
(b) www.finance.yahoo.com (retreived Nov. 5, 2014).
(c) www.zacks.com (Retreived Nov. 6, 2014).
(d) www.reuters.com (retreived Nov. 6, 2014).

DCF MODEL - NON-UTILITY GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Cost of Equity Estimates			
	Company	V Line	IBES	Zacks	Reuters
1	Church & Dwight	11.3%	11.6%	11.7%	10.6%
2	Coca-Cola	9.6%	6.9%	9.3%	6.9%
3	Colgate-Palmolive	12.8%	10.8%	10.9%	10.3%
4	ConAgra Foods	11.0%	12.3%	11.2%	13.7%
5	Gen'l Mills	10.3%	9.8%	10.9%	9.3%
6	Hormel Foods	12.7%	12.7%	9.7%	NA
7	Johnson & Johnson	9.2%	9.3%	8.7%	9.3%
8	Kellogg	9.7%	9.0%	9.1%	7.4%
9	Kimberly-Clark	12.1%	9.8%	10.3%	9.8%
10	McCormick & Co.	10.4%	11.0%	10.3%	11.0%
11	McDonald's Corp.	10.7%	9.1%	10.9%	8.6%
12	PepsiCo, Inc.	11.4%	10.7%	10.8%	10.4%
13	Procter & Gamble	10.6%	11.4%	11.1%	11.4%
14	Smucker (J.M.)	10.6%	10.2%	9.7%	10.1%
15	Verizon Communic.	12.5%	11.6%	12.7%	12.8%
16	Wal-Mart Stores	9.0%	8.1%	9.3%	6.7%
	Average (b)	**10.9%**	**10.5%**	**10.4%**	**10.3%**
	Midpoint (c)	**10.9%**	**10.4%**	**10.7%**	**11.1%**

(a) Sum of dividend yield (Exhibit No. 12, p. 1) and respective growth rate (Exhibit No. 12, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	**)**	
A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	
Environmental Compliance Plan; (3) An Order	**)**	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

JEFFREY B. BARTSCH

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jeffrey B. Bartsch, being duly sworn, deposes and says he is the Director, Tax Accounting and Regulatory Services for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Jeffrey B. Bartsch

Jeffrey B. Bartsch

STATE OF OHIO)
) Case No. 2014-00396
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffrey B. Bartsch, this the 10 day of December, 2014.

K. Nicol

Notary Public

My Commission Expires: 12/14/2015

DIRECT TESTIMONY OF
JEFFREY B. BARTSCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
JEFFREY B. BARTSCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Jeffrey B. Bartsch. I am the Director of Tax Accounting and Regulatory Support for American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent company of Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

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

A. I earned a Bachelor of Business Administration Degree in Accounting from Ohio University in 1979. I am a Certified Public Accountant and have been licensed in Ohio since 1981. I am also a member of the American Institute of Certified Public Accountants. I was first employed by Arthur Andersen & Co. in 1979 in the Audit section where I was assigned to various clients, including those in the electric utility industry. In 1985, I accepted a position with the AEPSC Tax Department. Since that time I have held various positions until June 2000 when I was promoted to my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES?

A. As Director of Tax Accounting and Regulatory Support, my responsibilities include oversight of the recording of the tax accounting entries and records of AEP and its subsidiaries, including Kentucky Power. I am also responsible for coordinating the development of state and federal tax data to be provided by the AEPSC Tax Department in regulatory proceedings. I have attended numerous tax, accounting and regulatory seminars throughout my professional career.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. In addition to previous testimony before the Public Service Commission of Kentucky ("Commission"), I have filed testimony before the Public Utilities Commission of Ohio on behalf of Columbus Southern Power Company and Ohio Power Company; with the Michigan Public Service Commission on behalf of Indiana Michigan Power Company; with the Louisiana Public Service Commission on behalf of Southwestern Electric Power Company; and with the Federal Energy Regulatory Commission in a transmission rate case for the eastern AEP Operating Companies. I have also filed testimony with and testified before the Public Utility Commission of Texas on behalf of AEP Texas Central Company, AEP Texas North Company, Southwestern Electric Power Company and Electric Transmission Texas, LLC. In addition, I have filed testimony with and testified before the Virginia State Corporation Commission on behalf of Appalachian Power Company, the Public Service Commission of West Virginia on behalf of Appalachian Power Company and Wheeling Power Company and with the Indiana Utility Regulatory Commission on behalf of Indiana Michigan

Power Company. Like Kentucky Power, all of these companies, except Electric Transmission Texas, LLC, are AEP operating companies.

III. PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my testimony in this proceeding is to calculate the Gross Revenue Conversion Factor, to present and support the jurisdictional federal, state and local income taxes to which Kentucky Power is subject, and to support certain fixed, known and measurable ratemaking adjustments to the test year ended September 30, 2014 related to these income taxes.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring Exhibit JBB-1 which represents Kentucky Power's Stand Alone § 199 Deduction.

IV. GROSS REVENUE CONVERSION FACTOR

Q. PLEASE DESCRIBE THE GROSS REVENUE CONVERSION FACTOR (GRCF).

A. The GRCF represents the factor necessary to determine the incremental amount of gross revenue required to generate an additional dollar of operating income after accounting for the effects of uncollectible accounts, Commission assessment fees and State and Federal income taxes.

Q. HOW WAS THE GRCF RATE DETERMINED?

A. The same methodology was used in this case as was utilized in the Company's prior base rate cases. The uncollectible accounts rate and commission assessment fees rate were provided to me by Company Witness Wohnhas and the state income tax rates and apportionment factors are based on the most recent state income tax return information and are currently being used in the monthly closing accrual process. Please see Section V, Workpaper S-2, Page 2.

Q. DID THE COMPANY REFLECT A SECTION 199 MANUFACTURING DEDUCTION AS A COMPONENT OF THE GRCF?

A. No.

Q. HAS THE COMMISSION INCLUDED A SECTION 199 MANUFACTURING DEDUCTION AS A COMPONENT OF THE GRCF IN PREVIOUS ENVIRONMENTAL RATE CASE ORDERS?

A. Yes. In Case No. 2005-00068 the Commission held that the Section 199 deduction "should be recognized and reflected in the gross-up factor … to the rate of return calculations for Big Sandy's environmental surcharge rate base."[1] That decision was affirmed on appeal by the Kentucky Court of Appeals in *Commonwealth ex rel. Stumbo v. Kentucky Public Service Comm'n*.[2]

Q. DID THE COMPANY FOLLOW THE COMMISSION'S METHODOLOGY FROM THE ENVIRONMENTAL RATE FILINGS AND INCLUDE THE SECTION 199 MANUFACTURING DEDUCTION AS A COMPONENT OF THE GRCF?

---

[1] Order, *In the Matter of: Application of Kentucky Power Company for Approval of an Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities and to Amend Its Environmental Cost Recovery Tariff*, Case No. 2005-00068 at 26-27 (Ky. P.S.C. September 7, 2005).

[2] 243 S.W.3d 374, 383 (Ky. App. 2007).

A. No. The Environmental Rate Orders were made before the Commission had the benefit of history with regards to the actual amount of manufacturing deduction that the Company would be able to claim on its tax returns. The Section 199 deduction was a new permanent Federal Income tax deduction that started in 2005. As described later in my testimony, AEP has not been able to claim this deduction on most of its Consolidated Federal Income Tax returns and Kentucky Power would not have been able to claim this deduction on many of its Federal Income Tax returns had it filed on a stand-alone basis.

Q. DOES IT MAKE A DIFFERENCE WHETHER THE SECTION 199 DEDUCTION IS INCLUDED IN THE GRCF AS OPPOSED TO IT BEING INCLUDED AS A SEPARATE SCHEDULE M ADJUSTMENT IN THE FEDERAL INCOME TAX CALCULATIONS?

A. Yes. If the Section 199 deduction is included in the GRCF, it assumes that the Company will be able to claim a deduction on each and every income tax return. The Section 199 deduction is not an automatic deduction that can be taken on the income tax returns. It is determined on an annual basis based on the facts and circumstances and is more closely aligned with taxable income not book income. Including the Section 199 deduction as a component of the GRCF assumes that the book return on production activities will approximate the Qualified Production Activities Income (QPAI) which would be used in calculating the Section 199 manufacturing deduction.

Q. PLEASE EXPLAIN WHY BOOK INCOME WOULD BE DIFFERENT THAN QPAI?

A. The primary difference between book income and QPAI is that QPAI is derived from taxable income associated with generation activities only. By using generation related book income, the impact of all book/tax temporary differences, including bonus tax depreciation, is excluded. There is no direct link between book income and QPAI due to the differences in the reporting of revenues and expenses between book and tax purposes.

Q. WHAT IS THE IMPACT IF THE COMMISSION CONTINUES TO INCLUDE THE SECTION 199 MANUFACTURING DEDUCTION AS A COMPONENT OF THE GRCF?

A. The years in which the Company would have been able to claim this deduction on a stand-alone tax return basis are very limited. By embedding this deduction in rates by way of the GRCF, the Commission is passing along a permanent tax deduction in rates (through reduced income tax expense) that simply does not exist. See Exhibit JBB-1.

Q. WHAT IS THE COMPANY'S RECOMMENDATION FOR INCLUDING THE BENEFIT OF THE SECTION 199 MANUFACTURING DEDUCTION IN BASE RATES?

A. As outlined later in my testimony, the Company recommends that the Commission take advantage of historical evidence by including a Schedule M for the Section 199 Manufacturing Deduction in the income tax calculations rather than using hypothetical information by including it as a component of the GRCF. In this Case, the Company has used the average Schedule M deduction from the last three Kentucky Power stand-alone Federal income tax returns.

Q. WHY USE THE STAND-ALONE TAX METHOD FOR KENTUCKY POWER INSTEAD OF AN ALLOCATION OF A SHARE FROM THE AEP CONSOLIDATED FEDERAL INCOME TAX RETURNS?

A. We believe that a stand-alone approach is more consistent with rate-making concepts than the consolidated tax return result. If the consolidated Federal tax return approach had been used, Kentucky Power would have only been eligible for the Section 199 deduction one time since 2005. However, the tax deduction computed on a stand-alone basis yields a deduction for the Company unrelated to the limitations associated with the computations in the consolidated AEP tax return. Unlike the GRCF gross-up method, which overstates the deduction and the consolidated Federal tax return method which may understate the benefit, we believe the stand-alone approach best reflects the true value of the benefit to Kentucky Power.

The stand-alone approach also is consistent with the court of appeals explanation in the appeal from the Commission's decision in Case No. 2005-00068:

> Here the Commission is applying the method it has used historically - the stand-alone entity method - which, it appears, KP is in overall agreement with. Use of that method will, no doubt, have its ups and downs for the utility. However, a new federal tax deduction has been passed into law which the Commission reasonably recognized in calculating KP's allowable tax expense.[3]

[3] 243 S.W.3d 374, 383 (Ky. App. 2007).

V. JURISDICTIONAL STATE AND FEDERAL INCOME TAXES

Q. PLEASE DESCRIBE THE COMPUTATION OF JURISDICTIONAL STATE AND CURRENT FEDERAL INCOME TAXES.

A. The computation of jurisdictional Current Federal Income Tax is accomplished by first allocating the Pre-Tax Book Income and the various Schedule M Adjustments used in the determination of the Company's total separate return federal taxable income, and applying the statutory federal income tax rate of 35%, as shown in Section V, Exhibit 3. The computation of jurisdictional Deferred Federal income tax is accomplished by applying the appropriate federal income tax rate to the allocated normalized timing differences, as shown in Section V, Exhibit 3, and by amortizing the allocated balances of the embedded Deferred Federal income taxes balances over the appropriate remaining lives. The computation of jurisdictional Deferred Investment Tax Credit is accomplished by amortizing the allocated balances over the appropriate remaining lives. The State income tax is calculated on the same basis as the Federal income tax expense as shown in Section V, Exhibit 3. Company Witnesses Vaughn and Listebarger prepared the jurisdictional allocation factors.

Q. WERE DEFERRED TAXES AND INVESTMENT TAX CREDITS ALLOCATED TO THE KENTUCKY RETAIL JURISDICTION?

A. Yes. Each component was allocated to the Kentucky retail jurisdiction as shown in Section V, Exhibit 3.

VI. RATEMAKING ADJUSTMENTS

Q. WHICH RATEMAKING ADJUSTMENTS ARE YOU SPONSORING?

A. I am sponsoring ratemaking Adjustments in Section V, Specifically; I am sponsoring the following ratemaking adjustments in Schedule 5:

ADJ	Description	Reference in Section V, Exhibit 2
46	Sales & Use Tax	W46
47	State Franchise Tax	W47
49	Removal Cost Schedule M	W49
50	Section 199 Manufacturing Deduction	W50
51	Mitchell Depreciation Schedule M	W51
56	ADIT Related to Big Sandy Coal Assets Removed from Rate Base	W56
59	Deferred State Income Tax Amortization	W59

Each of these adjustments is necessary in order to reflect an adjusted test year level of tax expense representative of ongoing operations. In addition, I have reviewed each of the ratemaking adjustments proposed by other Company witnesses and determined the proper income tax consequences as shown on Section V, Schedule 5.

Q. PLEASE DESCRIBE THE TAX ADJUSTMENTS THAT YOU ARE SPONSORING.

A. Adjustment 59 on tab W59 of Section V Exhibit 2 is necessary to amortize the Deferred State Income Tax (DSIT) balance that was recorded by Kentucky Power as part of the Mitchell Plant acquisition. Historically, Kentucky Power has not recorded Deferred State Income Taxes in ratemaking, so the Company proposes that this balance be amortized as a credit to tax expense over the remaining life of the Mitchell Plant. This amortization period is based on the new book depreciation rates which are being recommended in this rate filing by Company Witness Davis. Additional detail regarding this adjustment is provided below.

Adjustment 56 on tab W56 of Section V Exhibit 2 adjusts the ADFIT as of September 30, 2014 to be removed from rate base as a result of the net book value of the Big Sandy coal assets being removed from rate base.

Adjustment 49 on tab W49 of Section V Exhibit 2 adjusts the Removal Cost Schedule M to reflect the average of the deduction claimed on the last three tax returns filed. Since this Schedule M is treated as flow-through for ratemaking purposes and can fluctuate significantly between years, a three year average would be more representative of a normal annual Schedule M Adjustment.

Adjustment 50 on tab W50 of Section V Exhibit 2 adjusts the Section 199 Manufacturing Deduction that would have been claimed by Kentucky Power had it filed a separate Federal income tax return rather been included in the AEP System Consolidated Tax Return. This adjustment was based on the average of the last three stand-alone tax returns. Additional detail regarding this adjustment is provided below.

Adjustment 51 on tab W51 of Section V Exhibit 2 incorporates the annualization of the depreciation Schedule M's related to the Mitchell Plant acquisition. The test period currently only reflects 9 months of Mitchell Plant depreciation Schedule M's.

Adjustment 46 on tab W46 of Section V Exhibit 2 adjusts the Sales & Use Tax Expense to remove an out-of-period adjustment related to the settlement of a Sales & Use Tax Audit that was recorded during the test period.

Adjustment 47 on tab W47 of Section V Exhibit 2 adjusts the State Franchise Tax Expense to zero to reflect the fact that the West Virginia Franchise Tax will by law be completely phased-out starting in 2015.

Deferred State Income Tax Amortization Adjustment (59)

Q. WHY IS KENTUCKY POWER PROPOSING A DEFERRED STATE INCOME TAX AMORTIZATION ADJUSTMENT?

A. Historically, Kentucky Power has not included deferred state income tax expense in the ratemaking process. As a result of the Mitchell Plant acquisition which was recorded as a tax-free reorganization under §368 of the Internal Revenue Code, Kentucky Power also acquired their share of the existing Accumulated DSIT balance that was recorded on Ohio Power Company's books related to the Mitchell Plant. As of the acquisition date of December 31, 2013, Kentucky Power recorded $4,723,865 of Accumulated DSIT related to the Mitchell Plant. The Company is proposing that this balance be amortized over the remaining book life of the Mitchell Plant of 23.59 years. This remaining book life was obtained from Company Witness Davis. The effect of this adjustment is to decrease Kentucky Power's jurisdictional State Income tax expense by $197,446 as shown on Section V, Schedule 5.

Section 199 Manufacturing Deduction (50)

Q. HAS THE COMPANY REFLECTED THE ANNUAL EFFECT OF THE SECTION 199 DEDUCTION UNDER THE INTERNAL REVENUE CODE IN THE CALCULATION OF THE FEDERAL INCOME TAX OBLIGATION?

A. Yes. The Company reflected a Section 199 manufacturing deduction in the calculation of the Federal income tax liability in Section V, Schedule 5, even though Kentucky Power has not been able to claim this deduction since 2006. The Company has not been eligible to take advantage of the Section 199 deduction as a result of its participation in the AEP Consolidated Federal income tax return, however, a Section 199 deduction has been computed for this rate filing as if the Company had filed a separate stand-alone Federal Income Tax Return with the IRS. The Company has utilized this separate stand-alone tax return approach consistently in its tax calculations in previous rate filings with this Commission.

Q. HOW DID KENTUCKY POWER CALCULATE A SECTION 199 DEDUCTION FOR PURPOSES OF THIS RATE PROCEEDING?

A. Kentucky Power used a three year average of what its Section 199 deduction would have been on its 2011, 2012 and 2013 Federal income tax returns had it filed separate stand-alone corporate tax returns for those years.

Q. DOES KENTUCKY POWER EXPECT TO CLAIM A SECTION 199 DEDUCTION ON ITS 2014 OR ITS 2015 TAX RETURN?

A. At this time it is uncertain whether or not Kentucky Power will actually have positive qualified manufacturing income in 2014 or 2015 in order to receive a Section 199 deduction in either year.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Kentucky Power
Stand-Alone §199 Deduction

Exhibit JBB-1

		2005	2006	2007	2008	2009	2010	2011	2012	2013
1	Domestic Production Gross Receipts	852,995,718	740,947,246	616,038,125	688,653,583	484,208,134	556,866,990	556,188,427	458,864,027	500,669,202
2	Allocable Cost of Goods Sold	818,622,334	672,394,297	508,176,022	683,279,907	521,833,674	531,997,257	534,169,872	435,216,736	488,061,007
3	Directly Allocable Deductions, Expenses, or Losses	41,643,928	52,424,256	100,567,894	8,830,760	6,195,533	12,381,964	13,758,302	12,466,302	13,610,845
4	Indirectly Allocable Deductions, Expenses, or Losses	9,797,178	9,242,596	9,620,284	10,124,326	9,868,191	8,811,852	7,784,907	7,707,973	6,654,824
5	Add lines 2 Through 4	870,063,440	734,061,149	618,364,200	702,234,993	537,897,398	553,191,073	555,713,081	455,391,011	508,326,676
6	Qualified Production Activities Income (Loss)	(17,067,722)	6,886,097	(2,326,075)	(13,581,410)	(53,689,264)	3,675,917	475,346	3,473,016	(7,657,474)
7	Federal Taxable Income Limitation - Form 1040 - Line 30	11,852,070	34,659,105	26,773,624	1,377,727	(79,923,011)	30,366,964	29,192,737	19,277,355	21,088,012
8	Enter Smaller of line 6 or Line 7	(17,067,722)	6,886,097	(2,326,075)	(13,581,410)	(79,923,011)	3,675,917	475,346	3,473,016	(7,657,474)
9	Domestic Production Activities %	3.00%	3.00%	6.00%	6.00%	6.00%	9.00%	9.00%	9.00%	9.00%
10	Preliminary Domestic Production Activities Deduction	-	206,583	-	-	-	330,833	42,781	312,571	-
11	Form W-2 Wages	32,421,805	2,575,769	11,561,463	13,130,297	12,782,302	13,993,234	11,985,467	10,586,304	9,154,598
12	Wage Limitation Percentage	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
13	Form W-2 Wage Limitation	16,210,903	1,287,885	5,780,732	6,565,149	6,391,151	6,996,617	5,992,734	5,293,152	4,577,299
14	Enter the Smaller of Line 10 or Line 13	-	206,583	-	-	-	330,833	42,781	312,571	-
15	Domestic Production Activities Deduction	-	206,583	-	-	-	330,833	42,781	312,571	-

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION FOR GENERAL	)	
ADJUSTMENT OF ELECTRIC RATES	)	Case No. 2014-00396
OF KENTUCKY POWER COMPANY	)	

DIRECT TESTIMONY OF

ANDREW R. CARLIN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

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

Andrew R. Carlin

STATE OF OHIO	)
	) Case No. 2014-00396
COUNTY OF FRANKLIN	)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Andrew R. Carlin, this the 10th day of December, 2014.

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

Notary Public

My Commission Expires: October 1st, 2016

DIRECT TESTIMONY OF
ANDREW R. CARLIN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
ANDREW R. CARLIN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Andrew R. Carlin. My business address is American Electric Power, 15th Floor, One Riverside Plaza, Columbus, Ohio 43215. My position is Director of Compensation & Executive Benefits for the American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company"). AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including Kentucky Power.

Q. PLEASE DESCRIBE YOUR EDUCATION, PROFESSIONAL QUALIFICATIONS AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Arts Degree from Bowdoin College in 1988 with majors in Economics and Government. I also received a Masters of Business Administration Degree from the J. L. Kellogg Graduate School of Management at Northwestern University in 1992, with concentrations in finance, management strategy, and accounting.

From 1987 to 1988, I worked for Putnam Investor Services as a Shareholder Services Representative. From 1988 to 1990 and in the summer of 1991, I worked as an Associate Consultant and Research Analyst in the U.S. Compensation Practice for William M. Mercer, a leading international human resource consulting firm. From 1992 to 2000, I worked for Bank One Corporation, now part of J.P. Morgan Chase, in multiple planning, finance and compensation capacities.

I joined AEPSC as the Director of Executive Compensation & Benefits in 2000. In 2002 I took on responsibility for employee compensation, in addition to my executive compensation and benefits responsibilities. In my current position, I am responsible for, among other things, developing and maintaining effective and cost-efficient compensation programs for the Company and its subsidiaries.

Q. WHAT SERVICES DOES THE AEPSC COMPENSATION SECTION PROVIDE TO KENTUCKY POWER, AEP AND AEPSC?

A. The compensation department is responsible for the design, development, and administration of compensation and some of the benefit plans for the AEP System. The compensation group develops and administers the employee compensation programs to be fair and market competitive which enables the Company to attract, retain and motivate employees with the skills and experience necessary to provide reliable electric service, efficiently and effectively, for Kentucky Power customers. The compensation team conducts ongoing research and recommends changes to compensation programs as necessary to prudently manage total employee compensation. The compensation group also develops communications materials to manage and execute the plans, while monitoring compliance with federal and state regulations related to compensation.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in person or submitted written testimony in the following regulatory proceedings:

- On behalf of Kentucky Power Company in Kentucky Case No. 2013-00197;
- On behalf of Appalachian Power Company in Virginia S.C.C. Case No. PUE-2011-00037;
- On behalf of Indiana Michigan Power Company in Michigan Case No. U-16180;
- On behalf of Appalachian Power Company and Wheeling Power Company in West Virginia Case No. 10-0699-E-42T;
- On behalf of Public Service Company of Oklahoma in Oklahoma Cause No. 201300217; and
- On behalf of Southwestern Electric Power Company in Texas P.U.C. Docket No. 40443.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to demonstrate that the compensation for Kentucky Power employees and Kentucky Power's allocated share of compensation for AEPSC employees, which are the amounts Kentucky Power seeks to include in its cost of service, is reasonable, necessary, market-competitive, vital for the attraction and retention of employees with the skills and experience necessary to efficiently and effectively operate Kentucky Power's business, and beneficial to customers. In addition, I will discuss the steps that the Company has taken, in light of economic conditions and the Company's financial situation, to reduce compensation costs and total labor expense.

II. OVERVIEW OF COMPENSATION PRACTICES

Q. WHAT IS THE COMPANY'S OVERALL APPROACH TO COMPENSATION?

A. The Company's compensation strategy for all levels of positions is to provide a target total compensation opportunity (a combination of base salary or base rate plus a variable, at risk incentive portion) that is, on average, at the median of the market for similar positions.

Q. DOES THE USE OF MEDIANS AS BENCHMARKS MEAN THAT EMPLOYEE COMPENSATION WILL GENERALLY BE AT THE MEDIAN?

A. No. The median is used to assign job grades and ranges to each job as described above, but the base pay range for each job extends approximately 22.5 percent above and below the midpoint. Individual base pay rates may fall anywhere within the assigned range depending on individual performance, qualifications and other factors.

Q. WHAT TYPES OF COMPENSATION DOES THE COMPANY GENERALLY PROVIDE TO EMPLOYEES?

A. The Company compensates all employees with both base pay and an annual incentive compensation opportunity. I refer to the sum of these two types of compensation as total cash compensation ("TCC") herein. In addition to base pay and annual incentive compensation, approximately 550 positions in the AEP system are provided with a long-term incentive compensation opportunity. I refer to the total compensation opportunity provided to these management and executive positions (TCC plus long-term incentive compensation) as total direct compensation ("TDC") herein. For positions that do not typically receive long-term incentive compensation, TCC and TDC are the same. In this testimony "Total Compensation" is used to refer to the definition of compensation that includes all applicable forms of incentive compensation for the positions in question, TCC or TDC, as appropriate.

Q. HOW DO YOU DETERMINE THAT THE COMPANY'S COMPENSATION LEVELS ARE REASONABLE AND MARKET COMPETITIVE?

A. The Company primarily uses compensation surveys to compare its compensation rates and practices to those of other similar companies. Changes to the Company's compensation rates and practices are generally made as needed to maintain compensation that is competitive for each position relative to these survey comparisons of market competitive compensation. The Company's compensation department participates in or purchases numerous third-party compensation surveys each year that aid in ensuring that the Company's compensation levels are reasonable and market competitive. These surveys provide extensive compensation information for statistically significant samples of incumbents in a wide variety of jobs.

Specifically, the compensation department matches Company positions to the jobs included in these surveys and compares the compensation levels and practices for these positions with those of similar companies for similar positions with similar responsibilities, size and scope. After accounting for any differences in position scope, the compensation department uses market median total compensation, including the target value of all incentive compensation, as the primary compensation benchmark. Salary is also used as a point of comparison for all positions and TCC is also used as a point of comparison for positions for which the Company provides a long-term incentive compensation opportunity. This process for assigning and reviewing salary ranges and associated target incentive opportunities is consistent with the compensation practices of the majority of electric utilities and other large

U.S. companies. The surveys completed and used in this process for the historical test year are listed in EXHIBIT ARC-1 (Compensation Survey List).

Q. WHY IS TOTAL COMPENSATION CHOSEN AS THE PRIMARY POINT OF COMPARISON RATHER THAN BASE SALARY LEVELS?

A. Total compensation is chosen as the primary point of comparison because it includes base salary *and* all statistically significant types of incentive compensation. Survey information shows that annual incentive compensation is a statistically significant and often substantial component of market competitive compensation for nearly every position. Survey information also shows that long-term incentive compensation is a statistically significant and often substantial component of market competitive compensation for high level exempt and executive positions. Therefore, no assessment of market competitive compensation would be complete or valid without including annual incentive compensation for all positions and including long-term incentive compensation for high level exempt professional, managerial and executive positions. Because of the company provides incentive compensation, the Company's base pay levels are typically lower than those of companies that also seek to pay market competitively but provide less or no incentive compensation opportunity.

Q. DOES THE INCENTIVE COMPENSATION THE COMPANY PROVIDES TO EMPLOYEES CONTRIBUTE TO A TOTAL COMPENSATION OPPORTUNITY THAT EXCEEDS THE MARKET COMPETITIVE LEVEL?

A. No. The Company's incentive compensation is not a 'bonus' plan. Incentive compensation is a portion of employee pay that is at risk. This is designed to motivate employees and provide needed compensation that when it is combined with base pay, the incentive compensation portion brings employee total compensation to a reasonable market-competitive level. The target value of this incentive compensation portion of employee pay is a critical component of the market-competitive total compensation package, which the Company uses to attract and retain qualified employees.

Q. DO YOU BELIEVE IT WOULD BE REASONABLE FOR THE COMPANY TO ELIMINATE A PORTION OF ITS INCENTIVE COMPENSATION?

A. No, because this would reduce the employees' total compensation provided by the Company to less than the market competitive range for a substantial number of positions. Paying market competitive compensation enables the Company to attract, retain, and motivate the suitably knowledgeable, experienced and qualified employees it needs to efficiently and effectively provide services to customers, while minimizing overall expense, which is in the interests of all constituents. For example, the compensation expense saved by targeting compensation to less than the market competitive range would likely be more than offset by increased hiring and training expense due to increased employee turnover, as well as lower employee productivity while newer employees learn to perform their jobs safely, efficiently and effectively. This is particularly true for positions that require lengthy apprenticeships to learn the skills needed to work independently and safely, such as Line Mechanics.

Q. HOW ARE BASE SALARIES, EXCLUDING INCENTIVE COMPENSATION AND OVERTIME, DETERMINED FOR SALARIED EMPLOYEES?

A. Base salary offers for salaried positions are made by the Company management within the salary range for the job grade assigned to each position based on the qualifications and experience of the prospective employee relative to the requirements for the position. For jobs with multiple incumbents, the base salaries of other employees in the same position are also a major factor.

The Company also maintains a merit increase program for all salaried positions. The amount budgeted annually for merit increases is established by senior AEP management based on salary planning surveys, the market-competitiveness of the Company's compensation and the budget dollars available for salary increases. The merit program generally provides an annual salary increase opportunity to salaried employees based on their individual performance. However, due to financial constraints, the merit program was suspended for 2009 as part of an overall salary freeze and constrained to less than the market competitive level for 2010 for all salaried employees. For executives, the merit program was suspended completely for both of these years. The merit program was suspended and constrained in these years due to the Company's financial situation and the extraordinarily difficult economic conditions in its service territories. For 2011 the Company resumed the merit program with 3.2 percent merit budget of salary expense for that period, which was near the market median for such budgets. For 2012 the Company's merit budget was 2.675 percent, which was less than the market median for all employee categories. For 2013, the Company's merit budget was 3.0 percent which was the same as the market median. Since the merit budget was less than the market competitive level for several of these years and since none of these merit budgets were significantly above market, AEP's pay levels did not keep pace with market competitive compensation during this period. The Company's 2014 merit budget was 3.0 percent, which was also the market median for the year, and an additional 0.35% was added for line of progression promotions which had been highly constrained since 2009.

As part of the merit program, each employee's individual performance is evaluated on at least an annual basis. The amount of the "merit" increase awarded to each employee, if any, is based on a combination of factors, including their individual performance rating, their performance relative to their peers, the position of their salary within the salary range for their job, and the size of the merit budget.

Q. HOW DOES THE COMPANY'S OVERALL BASE SALARY INCREASE BUDGET COMPARE TO MARKET FOR THE YEARS 2009 THROUGH 2014?

A. Table ARC-1 below compares median utility industry base salary increase budgets for employees, other than those in hourly/craft positions, to Company's salary increase budget for the years 2009-2014.

Table ARC-1

	Non-exempt Salaried	Exempt	Executive
Utility Industry Market Median*			
2009 Actual	2.75%	2.50%	2.00%
2010 Actual	2.70%	3.00%	2.95%
2011 Actual	3.00%	2.90%	3.00%
2012 Actual	2.75%	3.00%	3.00%
2013 Actual	3.00%	3.00%	3.00%
2014 Projected	3.00%	3.00%	3.00%
Total	17.20%	17.40%	16.95%
The Company			
2009 Actual	0.00%	0.00%	0.00%
2010 Actual	2.00%	2.00%	0.00%
2011 Actual	3.20%	3.20%	3.20%
2012 Actual	2.68%	2.68%	2.68%
2013 Actual	3.00%	3.00%	3.00%
2014 Actual**	3.35%	3.35%	3.35%
Total	14.23%	14.23%	12.23%
Difference	-2.98%	-3.18%	-4.73%

*The Conference Board Research Report, U.S. Salary Increase Budgets for 2010, 2011, 2012 and 2013

**3.00% was merit budget; .35% was Promotional & Equity Adjustment

Also shown in Table ARC-1, the Company's base pay increase budgets have substantially lagged the market median overall for the last several years. While many companies pared back their salary increase budgets in 2009 due to economic conditions, the Company's salary freeze was a far more substantial response. While utility companies generally returned to nearly 3 percent increase for 2010, the

Company increased base wages by only 2 percent and maintained a salary freeze for executive positions. For 2011, the Company's base wage increases basically kept pace with the market median and did not make up a significant portion of the 2009 and 2010 shortfall. The Company's 2012 salary increase budget of 2.675 percent again lagged the market before returning to market median levels for 2013. For 2014, the Company allocated 3.35 percent total salary increase budget, slightly above the market median of 3.00 percent. Even with this additional funding this year, the Company's overall total salary increase budgets for non-exempt salaried and exempt positions still lag the market median by 2.975 percent and 3.175 percent over this period, while the salary increase budget for AEP executives was a total of 4.725 percent less than the utility industry market median.

Q. HOW ARE BASE PAY INCREASES ADMINISTERED FOR HOURLY/CRAFT EMPLOYEES?

A. Base pay increases for hourly/craft employees, such as line mechanics and meter readers, are provided as general increases, expressed as percentages of current base pay rates. General increases are negotiated with the labor unions that represent the Company's employees. The Company based its position in these negotiations on survey projections for market median general increases and market median total cash compensation paid by similar companies for these types of positions. As shown in Table ARC-2 below, pay increases for these types of employees have also lagged the market overall.

Table ARC-2

	Hourly/Craft Employees
Utility Industry Market Median*	
2009 Actual	2.50%
2010 Actual	2.85%
2011 Actual	2.90%
2012 Actual	3.00%
2013 Actual	3.00%
2014 Projected	3.00%
Total	17.25%
The Company	
2009 Actual	0.00%
2010 Actual	2.00%
2011 Actual	3.00%
2012 Actual	2.00%
2013 Actual	2.50%
2014 Actual	2.50%
Total	12.00%
Difference	**-5.25%**

*The Conference Board Research Report, U.S. Salary Increase Budgets Survey

The Company's total increase budget was 5.25 percent less than the market median for hourly/craft employees for the 2009 through projected 2014 period, including a 2.5 percent general increase that has been negotiated with most bargaining units for 2014. Reducing the growth of base wages is one of several difficult steps the Company has taken to address its financial situation and economic conditions in its service territory and such actions directly benefit customers by reducing the cost of the Company's electric service.

Q. WHAT OTHER STEPS HAS THE COMPANY TAKEN TO CONTROL COMPENSATION EXPENSE IN LIGHT OF THE GREAT RECESSION AND WEAK RECOVERY?

A. The additional steps the Company has taken include:

- Freezing external hiring from November 2008 through 2009;
- Freezing line of progression promotional increases, such as Accountant to Sr. Accountant, from November 2008 through 2010, other than for physical/craft positions;
- Substantially reducing the use of external contractors and temporary employees; and
- Substantially reducing the employee workforce through staff reductions and severance programs.

Q. HOW HAVE THE STEPS TAKEN TO CONTROL KENTUCKY POWER, AEP AND AEPSC'S COMPENSATION EXPENSES AFFECTED THE COMPETITIVENESS OF THE COMPANY'S COMPENSATION?

A. The below market merit and base pay increases for 2009 and 2012 caused the Company's base pay, target total cash compensation and target total direct compensation to decline relative to peer companies. As a result, base compensation levels for all types of positions (physical/craft, salaried and managerial) are below the market median on average although the Company's base compensation levels generally remain within the market competitive range (typically considered to be +/- 10 percent of the median for hourly/craft employees and +/- 15 percent for other employees). The Company's target annual incentive compensation has also fallen relative to market because these levels are calculated as a function of base compensation. As a result, the Company's target total cash compensation (base pay plus target annual incentive compensation) and target total direct compensation (total cash compensation plus target long-term incentive compensation) were also affected by the steps the Company has taken to control compensation expense, particularly the below market base pay increases.

III. COMPETITIVENESS OF TOTAL COMPENSATION

Q. HOW DOES KENTUCKY POWER, AEP AND AEPSC'S TARGET TOTAL COMPENSATION FOR PHYSICAL AND CRAFT POSITIONS COMPARE WITH MARKET DATA?

A. As shown in EXHIBIT ARC-2 (Kentucky Power TCC vs. Market for Technical, Craft and Clerical Positions), Kentucky Power's average TCC for the physical and craft positions included in the EAP Data Information Solutions, LLC 2013 Energy Technical Craft Clerical Survey is 7.2 percent below the market median. Assuming a market competitive compensation range of +/- 10 percent of the survey median, which is typical practice for such positions, Kentucky Power's average TCC is within but in the lower half of the market competitive range. However, if Kentucky Power's annual incentive compensation were to be excluded, then TCC for 9 of 12 physical/craft positions would fall below the market-competitive range and Kentucky Power's average TCC would fall 12.5 percent below the market competitive range. This shows that the annual incentive compensation paid by Kentucky Power is necessary of market competitive compensation for these positions and, thus, is a reasonable and appropriate cost of doing business that cannot be eliminated without an offsetting increase in base pay if total compensation is to remain competitive.

Q. HOW DOES KENTUCKY POWER'S AND AEPSC'S TARGET TOTAL COMPENSATION FOR NON-MANAGERIAL EXEMPT POSITIONS COMPARE WITH MARKET DATA?

A. EXHIBIT ARC-3 (TCC vs. Market for Exempt Positions) compares Kentucky Power's and AEPSC's compensation for non-executive exempt positions to those of similar companies, based on applicable external survey data. Using +/- 15 percent of the market midpoint as the market-competitive range, which is typical for exempt positions, this exhibit indicates that, on average, the Kentucky Power's and AEPSC's target TCC for these positions was 0.2 percent below the market median, which is well within the +/- 15 percent market competitive range. However, if Kentucky Power's and AEPSC's annual incentive compensation were to be excluded, then TCC for these positions would fall to 10.8 percent below the market median. While the Kentucky Power's and AEPSC's average TCC would remain at the low end of the market competitive range, 7of 22 individual positions (31.8 percent) would fall below the market competitive range. This shows that the annual incentive compensation opportunity Kentucky Power and AEPSC provide to these positions is necessary to maintain the competitiveness of their total compensation and is a reasonable cost of doing business that, practically speaking, cannot be eliminated without a corresponding increase in base pay.

Q. HOW DOES KENTUCKY POWER'S AND AEPSC'S TARGET TOTAL COMPENSATION FOR MANAGEMENT AND LEADERSHIP POSITIONS COMPARE WITH MARKET DATA?

A. The Human Resources Committee of AEP's Board of Directors frequently engages a nationally recognized, independent executive compensation consulting firms to conduct a compensation study of AEP's management and executive positions. The peer group used for this study consists of companies specifically selected by the Human Resources ("HR") Committee to represent the talent markets from which the Company must compete to attract and retain management and executive employees. The independent evaluation found that the Company's average total direct compensation (base salary, annual incentive compensation, and long-term incentive compensation) was within the market-competitive range (+/- 15 percent of the benchmark), although less than the market median. On average, for 27 executive positions, including all executive officers, the Company's base salaries, total cash compensation, and total direct compensation were within proximity of market. Accordingly, on aggregate, the Company's total compensation is market competitive. However, with respect to many of these positions, total compensation would fall below the market competitive range if the Company did not provide annual incentive compensation or replace it with some other form of compensation. Similarly, all of these positions would fall below the market competitive range if long-term incentive compensation was eliminated without an offsetting increase in some other form of compensation.

Once again, this shows that the incentive compensation is necessary to maintain the competitiveness of the total compensation package the Company provides to its employees. Therefore, the Company's total compensation, including the full target value of incentive compensation, is a reasonable cost of doing business.

Practically speaking, this incentive compensation cannot be eliminated without a corresponding increase in base pay or without diminishing the Company's ability to attract and retain the suitably knowledgeable and experienced management and executive employees that the Company needs to efficiently and effectively provide its services to customers.

IV. TYPES OF INCENTIVE COMPENSATION OFFERED BY KENTUCKY POWER, AEP AND AEPSC

Q. DO YOU HAVE COMMENTS ABOUT INCENTIVE COMPENSATION TRENDS AND ITS PREVELANCE?

A. Yes. Incentive compensation has withstood the pressures of the great recession and the unprecedented challenges of cost, risk, scrutiny and talent management issues facing employers today. It continues to be used nearly universally by public utilities and other U.S. companies to encourage desired behaviors and provide competitive total compensation opportunities. The compensation analyses discussed above in this testimony (EXHIBITS ARC 2 and 3) show that market median total compensation includes incentive compensation for 100 percent of the positions included in these studies, including all 12 technical, craft and clerical positions, in which 116 Kentucky Power employees are incumbents.

The Company provides both annual and long-term incentive compensation as part of a market-competitive total compensation package, not as a "bonus" on top of an already market competitive compensation package. As a result, incentive compensation does not increase payroll costs. In other words, if incentive compensation were not provided, the same dollar value of incentive compensation would need to be added to base pay in order for the Company to maintain the a market competitive of the total compensation package it provides to employees. Paying market competitive compensation enables the Company to attract, retain, and motivate the suitably knowledgeable and experienced employees it needs to efficiently and effectively provide its electric services to ratepayers. Furthermore, incentive compensation provides many additional and substantial benefits to ratepayers, which are described in detail later in this testimony.

Q. HOW COMMON ARE ANNUAL INCENTIVE COMPENSATION PLANS IN THE UTILITY INDUSTRY?

A. Annual incentive compensation plans are widespread in U.S. industry and among public electric utility companies. Median actual and target short-term incentive compensation is at least 5 percent of base salary for all levels of salaried energy services industry employees, including positions with base salaries of less than $30,000 (Towers Watson Data Services, 2013 CDB Energy Middle Management, Professional and Support Compensation Survey Report, p. 140). Over 100 Energy Services Industry companies participated in this survey. Furthermore, EXHIBIT ARC-4 (Towers Watson 2010 Annual Incentive Plan Design Survey Findings Report), states that:

> In today's turbulent economic environment, organizations face a 'perfect storm' of cost, risk, scrutiny and talent management issues. Amid these unprecedented challenges, annual incentive plans continue to play an important role in communicating and reinforcing critical organizational objectives, encouraging desired behaviors and providing competitive total direct compensation opportunities. (p. 4)

Q. WHAT ARE THE GENERAL BENEFITS OF ANNUAL INCENTIVE COMPENSATION?

A. The Company provides incentive compensation in lieu of larger base salaries because it improves the Company's performance without increasing overall compensation expense. It encourages cost control and aligns work with Company objectives, thereby increasing both employee and the Company performance. When incentive compensation is provided as a component of a market competitive total compensation package, it has no incremental cost above the cost of providing market competitive compensation using base pay alone.

Without compensation linked to the Company performance, management's compensation would be dependent only on retaining their position, which would reduce investment by discouraging managers from taking on prudent business investments. Such a compensation structure would be misaligned with the interests of both shareholders and customers, who depend on the Company's continued prudent and efficient investment in maintenance, system upgrades and system expansion for electric service. Similarly, linking compensation only to short-term performance is counter to both shareholder and customer interests because it would discourage investment necessary for the long-term success of the business. The age old adage "You get what you pay for" generally rings true with compensation. Paying only base compensation to employees at any level sends a clear signal to them that they need only perform their job well enough to avoid being fired for poor performance. For management employees, the absence of incentive compensation can discourage pursuit of projects that would be prudent investments for shareholders and customers. This is because pursuing major projects requires taking on prudent business risks that puts management's continued employment at risk. Similarly, a management compensation package that includes base pay and only short-term incentive compensation does little to encourage long-term projects, even projects that would be prudent investments for both shareholders and customers, because most long-term projects require upfront investment that reduces short-term earnings and often requires management to forego short-term incentive compensation.

Q. WHAT ADDITIONAL BENEFITS DOES ANNUAL INCENTIVE COMPENSATION PROVIDE?

A. Annual incentive compensation also:

- Helps to attract, retain and motivate the qualified employees the Company needs to efficiently and effectively provide electric service to customers;
- Communicates goals and objectives to employees in a manner that is more effective than otherwise possible. This focuses and more closely aligns employee efforts with these goals and objectives;
- Aligns the goals and objectives of departments throughout the organization with overall goals and objectives and, thereby, better ensure that all groups are working towards the same objectives;
- Encourages and motivates employees to achieve these goals and objectives;
- Rewards employees for their individual performance along with the Company's performance;
- Links some compensation for all employees to performance objectives so that all employees have a personal stake in achieving these objectives;
- Shifts a portion of compensation expense from a fixed to a variable expense that varies based on the performance of the Company. This reduces earnings volatility, business risk, and borrowing costs as well as the difficulties caused by more frequent and extensive changes in the size of the Company's work force that would be necessary without the earnings cushion that incentive compensation provides;
- Creates a culture of high performance and cost consciousness; and

- Reduces the Company's cost of service by virtue of the productivity increases, expense savings, and other benefits that it creates and that the Company would otherwise need to incur additional expense to provide.

A. Annual Incentive Compensation

Q. DESCRIBE THE ANNUAL INCENTIVE COMPENSATION PLANS APPLICABLE TO THIS PROCEEDING.

A. The Company's annual incentive plans cover all employees from hourly positions through executive management. The majority of the goals for Kentucky Power employees participating in this plan are measured at the Kentucky Power (operating company) level. For the test year of October 1, 2013 through September 30, 2014 there were separate annual incentive plans for Kentucky Power Utility Employees, AEPSC Utilities; Generation; Transmission, and several other smaller groups. The remaining employees and all staff function and shared services employees participated in an AEP Annual Incentive Compensation Plan for the Executive Council and Staff. As shown in EXHIBIT ARC-5 (2013 Company-Wide ICP Measures); the Company's annual incentive plans were primarily funded based on AEP's earnings per share (EPS), as has been the case in past years, but the weight on EPS was reduced from 100% to 75% for 2013 and 2014. For these years 10% was funded by safety performance and the remaining 15% was funded by performance on strategic initiatives that typically vary each year. There were also two extra credit measures: a 7.5 percent company-wide zero fatality measure and up to 5% extra credit for achieving cost savings targets and milestone objectives through culture and employee engagement activities. Each incentive plan also includes a balanced scorecard consisting of the following four categories of performance measures: Safety and Health, Operational, Financial or Regulatory and Strategic Initiatives. For Kentucky Power in 2013, the financial category consisted of a 10 percent Utility Group operations and maintenance ("O&M") vs. budget measure, which is a cost control measure, and a 15 percent Kentucky Power return on equity vs. target measure, which some may consider to be a rate of return measure, but which is really also a cost control measure for companies with regulated rates.

Q. PLEASE DESCRIBE THE ANNUAL INCENTIVE PROGRAM FUNDING MECHANISM.

A. As shown in EXHIBIT ARC-5 (2013 Company-Wide ICP Measures); the Company's annual incentive plans were primarily funded based on AEP's earnings per share (EPS), as has been the case in past years. However, the weight on EPS was reduced from 100% to 75% for 2013 and 2014. Of the remainder, 10% was funded by safety performance and 15% was funded by strategic initiative performance. There were also two extra credit measures: a 7.5 percent company-wide zero fatality measure and up to 5% extra credit for achieving culture and employee engagement objectives and cost savings. AEP's EPS incentive funding measure is set annually by the HR Committee in consultation with AEP executive management. The EPS performance measure is generally set at levels that are intended to provide a target payout on average and to only have about a 10 to 15 percent chance of producing either a zero or a maximum payout.

Q. HOW DO THE COMPANY'S INCENTIVE COMPENSATION PLAN TARGETS COMPARE TO OTHER COMPANIES IN TERMS OF THE

PERCENTAGE OF COMPENSATION PAID UNDER THE INCENTIVE PLAN?

A. Taking the Company's annual incentive compensation program as a whole, for 2013 the aggregate of the target awards for all participants was 9.6 percent of participant's base pay, including overtime. This is substantially below both the 16 percent median target for broad based plans. The AEP Systems' target annual incentive compensation has fallen relative to market because these levels are calculated as a function of base pay. Partially as a result, the AEP Systems' target TCC (base pay, plus target annual incentive compensation) is also below market median on average.

Q. IS IT APPROPRIATE FOR THE COMPANY TO REQUEST THE TOTAL ANNUAL COMPENSATION COST WHICH INCLUDES THE INCENTIVE PLAN TARGETS INCURRED DURING THE TEST YEAR IN THIS CASE?

A. Yes. The Company's annual incentive compensation program has been in place for more than 15 years and, as explained further below, the program has produced substantial additional benefits that have already been reflected in the Company's actual expenses for many prior years, including the test year. Because of these benefits, and because the incentive compensation serves only to bring total compensation to market competitive levels it is reasonable for ratepayers to bear the cost of incentive compensation as customers continue to receive its financial benefit through the lower cost of service that efficiencies driven by incentive compensation already provided in the current and prior base rate proceedings.

While the annual incentive program is expected to produce additional incremental benefits going forward, these benefits are likely to be small compared to the cumulative total of all ongoing benefits incentive compensation has produced in past years that have already been captured in rates or will be captured in rates through this proceeding. To the extent that substantial additional benefits are produced going forward, shareholders will pay the incremental incentive compensation expense associated with the above target portion of the incentive payouts this performance produces. This is appropriate because the financial benefit of this performance improvement would not be captured by customers until the next base rate case, although customers would immediately receive the benefits of any operational improvements. Therefore, as explained in more detail below, it is just and reasonable to include all of the cost of annual incentive compensation in the Company's cost of service for rate making purposes, except for the cost of any above target payouts.

EXHIBIT ARC-6 (CAHRS, *Evaluating the Utility of Performance Based Pay*), page 37, is an academic study that shows the substantial financial benefits that can result from linking pay to performance. The financial benefits shown in this study are the result of improved performance provided by a workforce whose pay was closely linked to performance.

The Company must provide a market competitive total compensation opportunity to efficiently and effectively attract and retain an adequately skilled and experienced workforce. Attracting and retaining such a workforce is necessary for the efficient and effective provision of service to customers and the operation of most aspects of the Company's business. Since the incentive compensation provided by the Company is part of this market competitive total compensation package, it has no incremental cost above the cost of providing market competitive compensation through base pay alone. Therefore, because the Company's annual incentive compensation (a) has no incremental cost to customers; (b) is likely to improve the performance of the workforce over time, as shown by the CAHRS study; and (c) is likely to result in improved operating effectiveness and cost control; it clearly has a substantial overall net benefit to customers.

Eliminating incentive compensation without an offsetting increase in base pay would result in a significant pay cut for all employees and, as previously shown, this would reduce total compensation for a substantial percentage of the Company's positions and employees to below the market-competitive range. Aside from the severe impact this pay cut would have on employee morale, it would reduce employee engagement, reduce productivity and increase employee turnover. This, in turn, would lead to increased hiring and training expense; cause additional reductions in productivity due to the need to train new employees and the considerable time it takes for new employees to acquire the work experience and skills necessary to perform their jobs safely and competently; and, ultimately decrease company performance while increasing overall costs.

Although the compensation that the Company's incentive programs provide could be replaced with additional base pay to achieve a market-competitive total direct compensation package, the loss of the many benefits of incentive compensation would reduce the company's ability to efficiently and effectively provide its electric services to customers. This in turn would lead to escalating costs and declining performance that would negatively impact customers.

Q. IS THE COMPANY REQUESTING THE INCLUSION OF ALL TEST YEAR ANNUAL INCENTIVE COMPENSATION IN ITS REVENUE REQUIREMENT IN THIS CASE?

A. No. The Company is requesting that the O&M expense for the *target* amount of annual incentive compensation for the test year be included in cost of service rather than the actual per books O&M expense. Annual incentive compensation during the test year was actually higher than the target amount due to above target EPS results for the test year. The Company is requesting the normalization of these costs to the target level, which is the amount of annual incentive compensation that the company expects to pay in an average year. It is also the amount of annual incentive compensation that the Company needs to pay, on average, in order to provide market competitive total compensation. The annual incentive compensation amount was adjusted to a level as supported by Company Witness Yoder in Section V, Exhibit 2, W25.

Q. WHAT ARE THE BENEFITS TO CUSTOMERS OF THE EARNINGS AND OTHER FINANCIAL MEASURES INCLUDED IN THE COMPANY'S ANNUAL INCENTIVE PROGRAM?

A. Tying funding for annual incentive compensation to the Company's earnings and cost control promotes efficient use of financial resources, which is paramount to providing reliable service at a reasonable cost to customers. The earnings and O&M measures included in the Company's incentive compensation programs convey the importance of maintaining financial discipline, and directly encourage employees to reduce expense, operate efficiently, and conserve financial resources. This has and will continue to directly benefit customers by reducing the Company's cost of service through cost savings that are passed on to customers in rates that are lower than they otherwise would if the Company did not use such performance measures.

Since annual incentive compensation expense is significant compared to Kentucky Power's and AEP's earnings, the EPS funding measure also helps ensure that incentive compensation payments do not impair the Company financially. This bolsters the Company's financial stability and reduces its earnings volatility, which benefits customers by reducing its cost of capital and helping to preserve capital during periods of weak earnings. It would be unreasonable to suggest that the Company should not have a mechanism, such as the EPS funding measure, to reduce or eliminate incentive compensation at times when it can ill afford to pay it. This mechanism benefits ratepayers during such times by better balancing the interests of other constituents with those of employees, rather than paying 100 percent fixed compensation to employees and leaving shareholders and ratepayers to absorb all the risk of economic volatility. Thus the EPS funding measure and incentive compensation in general, is a mechanism for balancing the interests of employees, ratepayers and shareholders.

Tying funding for incentive compensation to the Company's financial performance also sends a clear message to all employees that it is imperative for them to control costs and it provides a direct incentive for them to do so. This, in turn, enables the Company to complete work less expensively. Past performance with respect to O&M expense performance measures shows that, when such incentive plan measures are in place, AEP's business units manage their costs sufficiently to beat even stringent annual O&M budgets when major unbudgeted work additions and reductions are excluded.

Most of such savings have already reduced Kentucky Power's cost of service and rates for Kentucky customers on a dollar for dollar basis through prior base rate proceeding. If only 1 percent of the Company's O&M expense is saved each year due to the incentive compensation program, then millions of dollars per year has been saved by Kentucky customers by virtue of tying incentive compensation to the Company's financial performance measures.

Q. ARE THERE ANY INDIRECT COSTS TO CUSTOMERS OF THE COMPANY'S ANNUAL INCENTIVE PROGRAM?

A. No, there are no indirect costs that offset its benefit to customers. The earnings goals in the Company's annual incentive plan are established with stretch but achievable earnings targets. This ensures that incentive compensation up to target does not encourage company employees to pursue excessive earnings to the detriment of customers. Because the Company is only seeking inclusion of the target value of incentive compensation in its cost of service, the cost of any above target incentive compensation would be born entirely by shareholders. Furthermore, since the Company's revenue is regulated through this and other robust rate case proceedings, the only remaining way for the Company's employees to achieve these earnings objectives is through cost control, which benefits customers. In addition, the balanced scorecard of objectives the Company uses in its annual incentive program help ensure that some measures are not achieved at the expense of other important objectives, such as the safety, operations and environment objectives.

Q. DO THE BENEFITS OF THE COMPANY'S ANNUAL INCENTIVE PROGRAM EXCEED ITS COST FOR KENTUCKY POWER CUSTOMERS?

A. Yes. The Company's incentive compensation program does not increase the Companies' compensation expense beyond that required to provide market-competitive total cash compensation. Therefore, any reduction or elimination of incentive compensation would need to be offset by increases in base pay to maintain market competitive total cash compensation levels. The Company achieves substantial but unquantifiable cost savings through the financial discipline and other benefits that the Company's annual incentive compensation program provides, including reducing the overall cost of service and increasing the dollars available for investment in the maintenance and expansion of the Company's electrical system.

In summary, the Company's annual incentive program provides substantial benefits to customers and has no direct or indirect cost, above the cost of providing market competitive compensation through base pay alone. Therefore, it is just and reasonable to include the full cost of the Company's target level of incentive compensation in its cost of service.

B. Long-Term Incentive Compensation

Q. EXPLAIN THE COMPANY'S LONG-TERM INCENTIVE PROGRAM

A. The primary purpose of the Company's long-term incentive program is to encourage managers to make business decisions from a long-term perspective. For 2013 and 2014, the company provided long-term incentive awards in the form of performance units and restricted stock units ("RSUs").

Performance units are generally similar in value to shares of AEP common stock, except that the number of performance units that participants ultimately earn is tied to AEP's long-term performance and the participants' satisfaction of vesting conditions over a three-year period. All performance units granted and outstanding in the test year were granted with two equally weighted performance measures: three-year total shareholder return ("TSR") measured relative to a peer group of similar utility companies and three-year cumulative EPS relative to a Board-approved target. Both the TSR and EPS measures are capped at reasonable and appropriate levels so that they do not encourage the Company management to pursue these financial objectives at the expense of other objectives, such as safety.

RSUs are also generally similar in value to shares of AEP common stock, except that the number of RSUs that participants ultimately earn is tied to the participants' satisfaction of vesting conditions. Participants who remain employed with AEP through a vesting date receive a share of AEP common stock, or the cash equivalent, for each vesting RSU.

Q. IS THE COMPANY REQUESTING THAT LONG-TERM INCENTIVE COMPENSATION EXPENSE BE INCLUDED IN THE COST OF SERVICE IN THIS CASE?

A. Yes, the Company is requesting that the amount of long-term incentive compensation expense for the test year be included in its cost of service.

Q. IS THE LONG-TERM INCENTIVE PROGRAM REASONABLE AND NECESSARY TO EFFECTIVELY AND EFFICIENTLY SUPPORT RELIABLE ELECTRIC SERVICE?

A. Yes. The Company's long-term incentive compensation is a substantial component of the compensation for management employees and is critical to maintaining the market-competitiveness of compensation for such employees. As with annual incentive compensation, the Company's long-term incentive compensation is not incremental to an already market-competitive level of total direct compensation, and any reduction of this type of compensation would need to be offset by increases in other types of compensation in order to maintain the Company's ability to attract and retain the suitably skilled and experienced employees it needs to efficiently and effectively provide its electric service to customers. A large majority of public companies of AEP's size and complexity have similar programs, as do a large majority of public utility companies. Long-term incentive compensation is a substantial component that results in AEP's market competitive compensation for 100 percent of the 27 executive positions. Towers Perrin, a leading compensation consulting firm, reports that 99 of 102 companies that participated in their 2009 Energy Services Executive Compensation Survey have long-term incentive programs for top management employees.

Q. WHAT ARE THE DIRECT BENEFITS TO CUSTOMERS OF THE COMPANY'S LONG-TERM INCENTIVE PROGRAM?

A. As with annual incentive compensation, tying long-term incentive compensation to financial performance measures promotes the efficient use of financial resources, which is paramount to providing reliable service at a reasonable cost. Maintaining long-term financial discipline is imperative for the Company, its shareholders and its customers. The EPS and TSR measures associated with the performance units granted as part of the long-term incentive plan communicate this and strongly encourage its continued pursuit by tying a substantial portion of the compensation for management and executive employees to both internal and external measures of the Company's long-term financial performance. This encourages these employees to reduce expense, operate efficiently, and conserve financial resources, which directly benefits customers by keeping rates low.

Tying funding for long-term incentive compensation to AEP's earnings also retains additional capital in the Company during periods of weaker earnings performance, which bolsters the Company's financial stability and provides more capital for system maintenance during periods in which other sources of capital may be overly expensive or inaccessible. My discussion above regarding the benefits of reduced earnings volatility is also one of the benefits of long term incentive compensation. Tying long-term compensation to the Company's financial performance sends a clear message to participants that it is imperative for them to maintain financial discipline and it provides a direct incentive for them to do so. This, in turn, enables the Company to complete work less expensively. As with annual incentive compensation, if the long-term incentive program results in only a 1 percent annual O&M expense savings, then millions of dollars per year has been saved by Kentucky customers by virtue of this program.

Q. ARE THERE ANY INDIRECT COSTS TO CUSTOMERS FOR THE COMPANY'S LONG-TERM INCENTIVE PROGRAM?

A. No. AEP's long-term incentive goals are established at stretch but achievable targets. This ensures that customers are not paying for long-term incentive compensation that may encourage company employees to generate excessive earnings. In addition, any increase in long-term incentive compensation expense above the amount requested would be born entirely by shareholders, not customers.

The goals in the Company's long-term incentive plan are also balanced by the scorecard goals in the annual incentive plan to assure that the EPS and TSR goals are not achieved at the expense of other important objectives. As with annual incentive compensation, any increase in long-term incentive compensation that might be achieved by reducing spending in operations areas, for example, would likely be at least partially offset by a decrease in annual incentive funding due to the decline in the operating performance scores. As a result of this balanced approach to incentive compensation, AEP's long-term incentive compensation does not encourage behaviors that would be counter to customers' interests and there are not any significant indirect costs that would offset the benefits of long-term incentive compensation to customers.

Q. DO THE TOTAL BENEFITS OF THE COMPANY'S LONG-TERM INCENTIVE PROGRAM EXCEED ITS COST TO KENTUCKY POWER CUSTOMERS?

A. Yes. Similar to annual incentive compensation, the Company provides long-term incentive compensation as part of a market-competitive total direct compensation package. Therefore, the Company's long-term incentive compensation does not have an incremental cost to customers, beyond the cost of providing a market competitive total direct compensation package through other types of compensation. As with annual incentive compensation, the long-term incentive program has been in place for many years, so its accumulated ongoing benefits are already reflected in the Company's expense for the test year and incorporated into rates in prior rate proceedings. It is not appropriate for shareholders to pay the cost of maintaining long-term incentive compensation from which customers have already captured the financial benefit through a lower cost of service that is reflected in this and prior rate proceedings. While the long-term incentive program is expected to produce additional marginal benefit going forward, these additional benefits are likely to be small and incremental compared to the total benefit this program has created to date. It is not reasonable for the shareholders to be assigned the cost of this program while customers reap its benefits through a lower cost of service.

V. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY WITH RESPECT TO COST RECOVERY FOR COMPENSATION EXPENSE.

A. The design of the Company's compensation programs and, specifically, its annual and long-term incentive compensation programs, are reasonable and appropriate from the customer's perspective. These programs are necessary to ensure that the Company is able to attract, retain, and motivate the employees needed to efficiently and effectively provide electric service to its customers. The compensation that the Company provides, including annual and long-term incentive compensation, is a just, reasonable and prudent cost of doing business. This compensation is market competitive on a base pay, target total cash compensation, and target total direct compensation basis. Annual and long-term incentive compensation is provided as part of this overall market-competitive compensation package and does not represent an incremental expense to Kentucky Power's ratepayers. Therefore, I respectfully submit that it is just and reasonable to include the full cost of the Company's compensation, including the target level of both annual and long-term incentive compensation, in the Company's cost of service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Surveys Completed and Used for Compensation Comparisons

During the Historical Test Year

Towers Watson U.S. Compensation Data Bank (CDB):

2013 Energy Services Industry - Executive Compensation Survey Report

2013 Energy Services Industry - Middle Management, Professional & Support Compensation Survey Report

2013 General Industry - Executive Compensation Survey Report

2013 General Industry - Middle Management, Professional and Support Compensation Survey Report

2013 Custom AEP Peer Group - Executive Compensation Surveys

EAPDIS, LLC, 2013 Energy Technical Craft Clerical Survey – ETCCS

The Conference Board, U.S. Salary Increase Budgets for 2013

EXHIBIT ARC-2 (KPCO Target TCC vs. Market for Technical, Craft and Clerical Jobs)

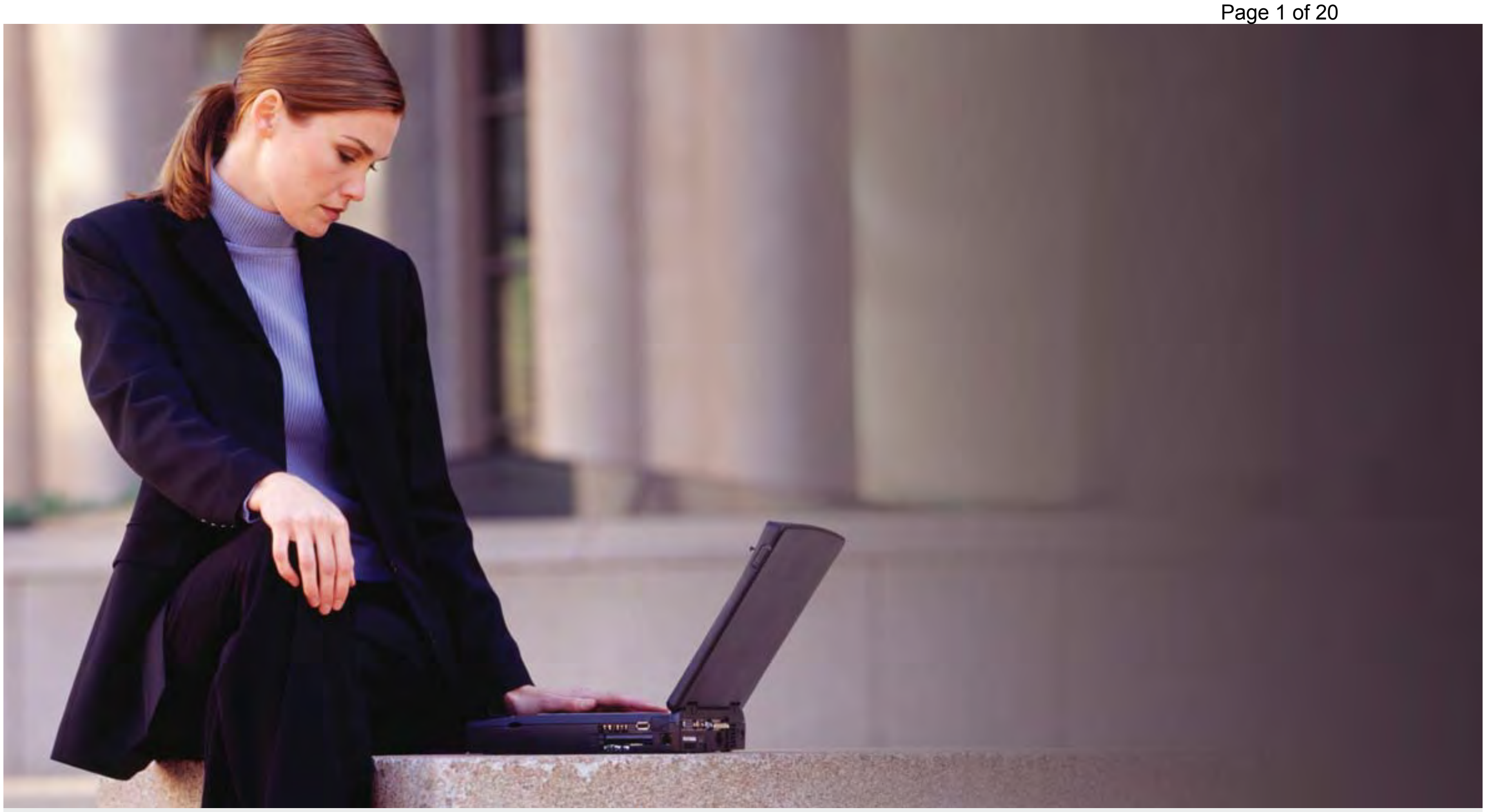
KPCO Target Total Cash Compensation (Target TCC) vs.
2013 EAPDIS Energy Technical, Craft & Clerical Survey (Southeast Region Data)

Survey Job	AEP Title	EEs	Base[1]	Target Annual Incentive[2]	Target TCC	ETC&C Survey Median Base[3]	ETC&C Survey Median Incentive	ETC&C Survey Median TCC	% Difference AEP TCC vs. Survey TCC	% Difference AEP Base vs. Survey TCC
Line Mechanic (OH/UG)	Line Mechanic-A	32	$68,080	$3,404	$71,484	$76,856	$1,456	$78,312	-9.6%	-15.0%
Storekeeper/Handler	Stores Attendant A	4	$54,662	$2,733	$57,396	$52,500	$1,575	$54,075	5.8%	1.1%
Substation Mechanic/Technician	Station Electrician A	5	$68,370	$3,418	$71,788	$76,856	$1,456	$78,312	-9.1%	-14.5%
Motor Vehicle Mechanic	Fleet Technician A	5	$63,993	$3,200	$67,193	$64,500	$1,935	$66,435	1.1%	-3.8%
Meter Mechanic	Meter Electrician-A	5	$67,442	$3,372	$70,814	$74,090	$2,018	$76,107	-7.5%	-12.8%
Trouble Service Mechanic	Line Servicer	30	$69,186	$3,459	$72,646	$80,954	$2,787	$83,741	-15.3%	-21.0%
Control Operator	Unit Operator	8	$70,845	$3,542	$74,387	$78,582	$3,286	$81,869	-10.1%	-15.6%
Certified Welder	Maintenance Welder	12	$71,157	$3,558	$74,715	$75,608	$2,850	$78,458	-5.0%	-10.3%
Instrument and Control Tech	Control Technician-Sr	7	$70,182	$3,509	$73,691	$77,750	$2,475	$80,226	-8.9%	-14.3%
Plant Machinist	Maintenance Machinist	1	$69,098	$3,455	$72,552	$71,614	$4,222	$75,837	-4.5%	-9.8%
Coal Yard Equipment Operator	Coal Equipment Operator	3	$61,603	$3,080	$64,683	$67,579	$2,787	$70,366	-8.8%	-14.2%
Plant Equipment Operator	Equipment Operator	4	$61,298	$3,065	$64,362	$71,781	$1,706	$73,486	-14.2%	-19.9%
	Total	116						**Average**	-7.2%	-12.5%
						% of Jobs Above Market Competitive Range[4]			None	None
						% of Jobs Below Market Competitive Range[4]			25%	83%

Notes

(1) As of September 30, 2014
(2) The Company's target payout is 5 percent of base earnings for all physical and craft jobs
(3) Annualized from April 2013 to September 2014 @ 2.0% salary growth rate
(4) A market competitive range of +/- 10 percent has been used for all physical and craft positions

EXHIBIT ARC-3 (TCC vs. Market for Exempt Positions)											Exhibit ARC-3
Compensation Survey Analysis- Exempt Positions											
										% Difference AEP	**% Difference AEP**
			EE	**AEP Incumbent Data**			**Survey Results[1]**			**Total Comp vs**	**Base vs Survey**
Survey Job		**AEP Title**	**Count**	**Avg Base**	**Incentive (2)**	**Total Comp**	**Base**	**Incentive**	**Total Comp**	**Survey Total Comp**	**Total Comp**
KPCO Positions (3)											
Electric Distribution Operations-Career Level	EDD010-P3	Distr Dispatcher I	2	$85,950	$8,595	$94,545	$87,100	$8,800	$95,900	-1.4%	-11.6%
Energy Delivery/Distribution Supervisor	EDD020-M1	Supv Distribution System	3	$100,667	$10,067	$112,605	$99,600	$9,800	$109,400	2.8%	-8.7%
Energy Delivery/Distribution Generalist/Multidiscipline - Career (P3)	EDD000-P3	Distribution Line Coordinator	2	$76,813	$7,681	$84,494	$82,700	$13,500	$96,200	-13.9%	-25.2%
Electric Distribution Engineering - Entry (P1)	AZE543-P1	Engineer III	1	$73,645	$5,155	$78,800	$64,900	$2,900	$67,800	14.0%	7.9%
Electric Distribution Engineering-Intermediate Level (P2)	AZE543-P2	Engineer II	3	$77,864	$7,786	$85,650	$76,400	$5,000	$81,400	5.0%	-4.5%
Electric Distribution Engineering-Career Level (P3)	AZE543-P3	Engineer I	1	$93,959	$9,396	$103,355	$97,100	$9,500	$106,600	-3.1%	-13.5%
Budget Analysis - Career (P3)	AFT020-P3	Resource Analyst I	1	$85,000	$10,500	$95,500	$79,300	$2,900	$82,200	13.9%	3.3%
Land/Right of Way - Career (P3)	ARE040-P3	Right of Way Agent Sr	1	$76,926	$9,500	$86,426	$87,200	$8,500	$95,700	-10.7%	-24.4%
AEPSC Human Resources (4)											
Diversity/EEO-Multi - Specialist (P4)	AHR110-P4	Sr Workforce Diversity Cons	1	$108,306	$16,246	$124,552	$113,300	$19,776	$133,076	-6.43%	-22.9%
HR-Multi - Career (P3)	AHR000-P3	HR Representative Sr	3	$71,497	$7,150	$78,646	$84,460	$5,562	$90,022	-14.46%	-25.91%
Recruitment-Multi - Intermediate (P2)	AHR140-P2	Recruiter-Senior	3	$77,220	$7,722	$84,942	$66,538	$2,266	$68,804	19.00%	10.90%
AEPSC Business Logistics (4)											
Materials Planning/Scheduling - Career (P3)	ASC015-P3	Material Coordinator	4	$76,304	$7,630	$83,934	$85,593	$5,562	$91,155	-8.60%	-19.46%
AEPSC Information Technology (4)											
Database Design and Analysis - Specialist (P4)	AID060-P4	IT Database Analyst Senior	7	$105,698	$15,855	$121,552	$117,317	$7,931	$125,248	-3.04%	-18.50%
Application Development Support - Intermediate (P2)	AID055-P2	IT Systems Analyst III	2	$70,825	$7,083	$77,908	$76,220	$2,472	$78,692	-1.01%	-11.11%
Application Development - Specialist (P4)	AID010-P4	IT Software Developer-Sr	38	$99,732	$14,960	$114,691	$109,180	$7,828	$117,008	-2.02%	-17.32%
Application Development - Career (P3)	AID010-P3	IT Software Developer I	45	$89,529	$8,953	$98,481	$94,760	$4,532	$99,292	-0.82%	-10.91%
Computer Systems Administration - Intermediate (P2)	AIT010-P2	IT System Administrator II	16	$74,370	$7,437	$81,807	$72,409	$3,811	$76,220	6.83%	-2.49%
Business Systems Analysis - Career (P3)	AID020-P3	IT Business Systems Analyst I	13	$90,592	$9,059	$99,652	$89,198	$5,047	$94,245	5.43%	-4.03%
IT Development - Career (P3)	AID055-P3	IT Systems Analyst I	16	$89,160	$8,916	$98,076	$91,876	$8,652	$100,528	-2.50%	-12.75%
AEPSC Accounting/Finance/Audit/Legal (4)											
General Accounting - Career (P3)	AFB010-P3	Sr Accountant	8	$74,725	$7,473	$82,198	$76,735	$4,635	$81,370	1.01%	-8.89%
General Accounting - Entry (P1)	AFB010-P1	Accountant III	11	$52,225	$2,611	$54,837	$54,590	$2,884	$57,474	-4.81%	-10.05%
General Accounting - Intermediate (P2)	AFB010-P2	Accountant I	13	$63,508	$4,446	$67,953	$64,787	$3,090	$67,877	0.11%	-6.88%
		Incumbent Count	194						**Average**	-0.2%	-10.8%
Notes:											
(1) All survey data aged to September 2014 at 3% annual rate											
(2) Reflects annual target incentive payout for job						% of Jobs Above Market Competitive Range[5]				4.5%	0.0%
(3) Survey Data from March 2014 Towers Watson Energy Services Middle Management & Professional Survey						% of Jobs Below Market Competitive Range[5]				0.0%	31.8%
(4) Survey Data from March 2014 Towers Watson General Industry Middle Management & Professional Survey											
(5) A market competitive range of +/- 15 percent has been used for all exempt positions											



2010 Annual Incentive Plan Design

Survey Findings Report

TOWERS WATSON

Key incentive plan changes clients have either discussed or implemented include:

- Discretionary awards, possible adjustments to plan metrics and associated communications
- Additional/new metrics (e.g., focus on expense management, use of capital)
- Broader performance ranges, through lower thresholds
- More emphasis on individual objectives
- More ongoing communication to help build employee line of sight

To help companies ensure that their annual incentive plans provide competitive reward opportunities and remain effective in supporting key business and talent goals, Towers Watson conducts ongoing research in annual incentive plan design and operations. Our latest survey of annual incentive plan practices highlights the continuing evolution in plan design, along with some emerging trends in plan management.

2010 Annual Incentive Plan Design

Survey Findings Report

Table of Contents

Overview

In today's turbulent economic environment, organizations face a "perfect storm" of cost, risk, scrutiny and talent management issues. Amid these unprecedented challenges, annual incentive plans continue to play an important role in communicating and reinforcing critical organizational objectives, encouraging desired behaviors and providing competitive total compensation opportunities.

As economic uncertainty continues to cloud the picture, Towers Watson's work with clients during 2009 and the first quarter of 2010 confirms that many pay interventions introduced in response to the current financial crisis have been temporary and tactical, rather than strategic.

Among most companies, decisions about cost still predominate, but the importance of weighing short- and long-term implications is growing. Given that financial and operational results are below historical norms, annual incentive compensation plans are under pressure to respond. But whether adjustments to overall plan design are warranted or have occurred is unclear.

Against this backdrop, Towers Watson's latest survey of annual incentive plan design practices has uncovered some areas where changes have occurred and others where previous plan designs remain the same.

The Towers Watson 2010 Annual Incentive Plan Design Survey is based on a profile of 212 large companies (see Appendix on page 19 for survey participant data). This survey provides detailed information about how organizations based in the U.S. and Canada design annual incentive plans for their top executives. U.S. companies represent 83% of the sample, and Canadian companies represent 17%. Although additional companies can and have joined the survey, the results in this report are based on participants as of December 1, 2009. Towers Watson first conducted the Annual Incentive Plan Design Survey in 1996, following up in 2001 and 2005.

Current plan design practice data are presented, by section, in the remainder of this report of survey findings. Highlights of key trends, developments and changes are organized into three groups:

1. Trends identified in our 2005 survey that remain stable and/or have expanded in practice/ prevalence in 2010:

- There is continuing consistency in incentive plan designs within organizations, reflected by the finding that more companies are altering eligibility requirements and offering a single annual incentive plan for executives and other employees.
- Companies continue to be thoughtful about the specific definition of earnings used to measure performance, with relatively less use of earnings per share (EPS) and greater use of earnings before interest and taxes (EBIT or EBITDA) and operating earnings in their annual incentive plans.
- Most companies use two or more performance measures in their annual incentive plans, and the use of sales/revenue as a performance measure has maintained high prevalence.
- There is continued use of a broader and more complex range of performance measures to improve measurement and line of sight.
- Incentive zones and associated payout ranges remain largely unchanged over the past 10 years.
- There is a continued decrease in the use of voluntary deferred compensation arrangements, as companies have adjusted to the additional 409A restrictions that took effect in 2005.

"There is continued use of a broader and more complex range of performance measures to improve measurement and line of sight."

2. Practices identified as emerging/evolving in 2005 that have not taken a firm hold in the market and/or have retreated in 2010:

- The movement away from thresholds and maximum performance levels to mark the bottom and upper limits of bonus payout zones has not occurred.
- Tying target bonus opportunities to peer group or market is a near-universal practice, and the trend away from this approach, as reported in 2005, has reversed.
- In some areas, the use of discretion in annual incentive plan design remains steady. There has not been significant growth in this practice and, in some areas, the use of discretion has decreased. These findings suggest that even in the midst of economic uncertainty — and often increased pressure to exert more discretion — companies have not made significant changes in this area.

3. New approaches in designing annual incentive plans:

- Plan costs — spending on annual incentive plans as a percentage of net income or revenue — are mostly aligned with data collected in 2005, except that actual spending for the most recently completed year (as of October-November 2009) was below target and historical levels. In addition, actual spending for the current/ongoing year is generally expected to be 20% to 30% below target.
- Plan funding — the method used to determine aggregate spending — has seen continued growth in the use of financial results-based funding formulas; the most prevalent funding measures are cash flow and operating income (versus net income in 2005).
- While the number of performance measures used has not changed and there have been small adjustments to the overall list of measures, there has been an increase in the prevalence of cash flow and EBIT/EBITDA.
- The use of individual performance as a weighted measure has been stable for the CEO position at about one-third prevalence, and has increased from one-third to about half for positions below the CEO level.
- In addition to using individual performance, companies are showing increased use of measures at group/sector and business unit/division levels. Companies appear to be willing to increase the complexity and differentiation within the plans in exchange for greater line of sight and linkages to performance.
- The area of setting performance expectations has changed, with a majority of companies currently basing goals on "expected business conditions." In the past, this method was used less frequently and was less common than goal setting based on budgeted performance and year-over-year growth or improvement. This trend may be a temporary reaction to the current economic environment, or it may continue into the future.

Eligibility

“An increasing number of companies align their incentives across the organization, most likely to encourage greater consistency of focus and effort.”

This study focuses on annual incentive plans that include the highest level of corporate management, typically the CEO and the company’s senior management group. Over the past decade, a majority of companies have shifted away from offering an executive-only annual incentive plan and separate plans for other employees. Today, most companies offer an annual incentive plan to both executives and employees below the executive level.

All the surveyed plans are grouped into the following categories, according to the types of eligible participants:

- **Top-level executive plans** cover only the CEO, direct reports to the CEO and second-tier executives (i.e., direct reports to the CEO’s direct reports) — 13% of the sample.
- **Middle management and above plans** cover not only the CEO and senior executives, but also middle managers — 25% of the sample.
- **Broad-based plans** typically extend to certain professional and administrative employees in addition to the CEO, other senior executives and middle management — 62% of the sample.

Continuing a trend started in 2005, a majority of the surveyed plans fall into the category of broad-based plans. In 2001, over half of the surveyed plans were top-level executive plans. An increasing number of companies align their incentives across the organization, most likely to encourage greater consistency of focus and effort.

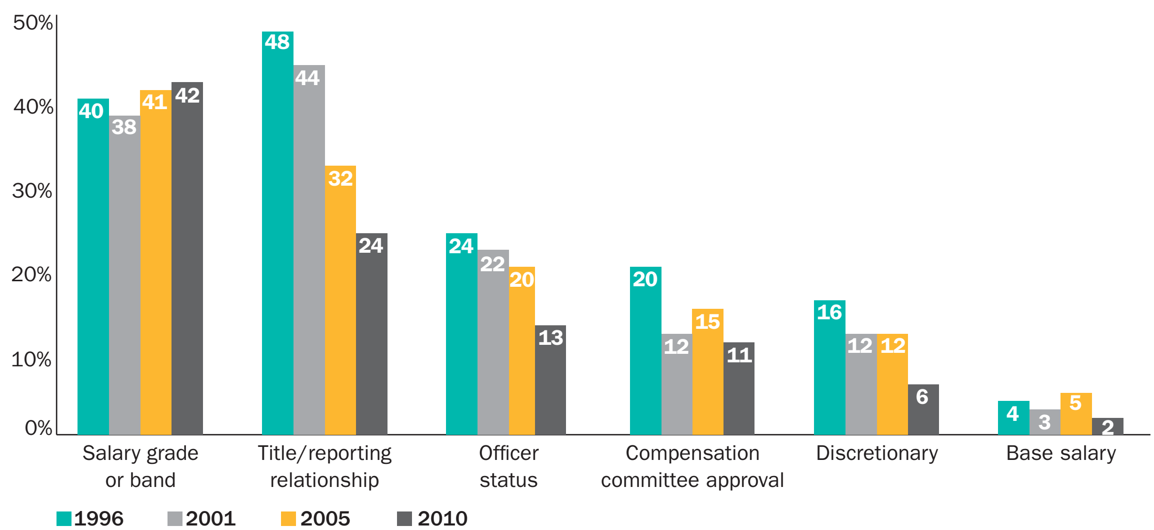
The number of plan participants, as a percentage of total employees, varies by the type of plan:

- **Top-level executive plans** — 0.4% of total employees at the median
- **Middle management and above plans** — 3.1% of total employees at the median
- **Broad-based plans** — over half of these plans include all (or all nonunion) employees in the company; of the broad-based plans that do not include all employees, the median participation is 20% of total employees

Eligibility Criteria

Eligibility to participate in an incentive plan is determined at each company by one or more factors *(Exhibit 1)*. In the 2010 survey, the most common factor for determining eligibility is an employee’s salary grade or band. This differs from prior years, when position title, reporting relationship or officer status was a more common factor used to determine incentive plan eligibility. This finding is consistent with the trend toward including employees at various levels in the organization in one plan. In the past, when most survey plans were top-level executive plans that included only the CEO, direct reports to the CEO and their direct reports, an employee’s reporting relationship was a simple, straightforward identifier of role and contribution. With plans now extending further into the organization, a more rigorous, contribution-based system (such as salary grades or bands) is used to determine eligibility.

Exhibit 01. Historical Comparison of the Basis for Determining Plan Eligibility



Plan Costs

Incentive plan costs are always a challenging issue for companies as they seek to strike a balance between cost management and competitive bonus levels that will motivate top performance. Given these pressures, often made more intense by heightened executive pay-level scrutiny by shareholders, analysts and the media, companies are carefully monitoring the cost of incentives.

In the 2010 survey, we collected information that allows us to summarize costs for the most recently completed fiscal year (both actual and target) and the current/ongoing fiscal year at target. Across all plans and comparison approaches, reflecting recent economic challenges among participants, actual plan costs are below target levels. These figures may not reflect the total costs of incentives for the companies, because costs may be incurred under other incentive plans not reported in this survey. However these figures do provide a comparison point against which to judge incentive spending.

One insightful way to assess plan costs is to compare the cost of an incentive plan in a given year to the net income generated by the company in that year. The percentage of net income spent on a particular incentive plan is a function of, among other things, how many people participate in the plan, the measures used for incentive purposes and the size of the organization.

Median Plan Cost as % of Net Income

In this year's survey, the portion of net income spent on incentive plans at all three levels is relatively closely aligned with the data in the 2005 survey, except for the actual most recent fiscal-year costs.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	**Most Recent Fiscal Year — Actual**	**Current/Ongoing Fiscal Year — Target**	**Most Recent Fiscal Year — Actual**
Top-level executive plans	**1.9%**	**1.9%**	**1.7%**	**2.9%**
Middle management and above plans	**4.9%**	**2.8%**	**5.3%**	**5.5%**
Broad-based plans	**6.9%**	**5.0%**	**7.1%**	**6.9%**

Median Plan Cost as % of Revenue

Incentive plan costs as a percentage of company revenue provide an indication of how incentives relate to the size of the organization, with 2010 results similar to 2005 results.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	**Most Recent Fiscal Year — Actual**	**Current/Ongoing Fiscal Year — Target**	**Most Recent Fiscal Year — Actual**
Top-level executive plans	**0.14%**	**0.12%**	**0.16%**	**0.13%**
Middle management and above plans	**0.29%**	**0.17%**	**0.34%**	**0.37%**
Broad-based plans	**0.63%**	**0.44%**	**0.69%**	**0.64%**

Median Plan Cost as % of Aggregate Base Salaries of Participants

It is important to evaluate the amount spent on incentives in relation to the aggregate base salaries of employees in the plan. Not surprisingly, top-level executive plans pay out the highest percentage of the aggregate base salaries of plan participants.

	2010 Survey Plan			2005 Survey Plan
	Most Recent Fiscal Year — Target	Most Recent Fiscal Year — Actual	Current/Ongoing Fiscal Year — Target	Most Recent Fiscal Year — Actual
Top-level executive plans	41%	36%	41%	44%
Middle management and above plans	27%	24%	28%	32%
Broad-based plans	16%	12%	16%	17%

Plan Costs for Current/Ongoing Fiscal Year

Since the survey data were collected during October-November 2009, we asked participants to report the anticipated/estimated plan costs for the current/ongoing fiscal year (generally, the 2009 fiscal year). This was a new data point in the survey and was not reported by a majority of participants. While we cannot report statistics similar to the plan cost tables above, we conclude that actual spending for the current/ongoing year is generally expected to be in the range of 20% to 30% below target.

Plan Funding

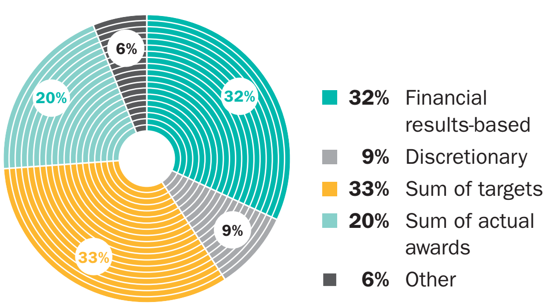
The method used to determine the aggregate size of an incentive pool from which all incentives will be paid plays an important role in achieving a fair balance between the interests of shareholders and plan participants.

Under the *sum-of-targets approach,* the aggregate amount of awards to be paid under the plan in a given year is determined by adding the target awards of all participants. The *sum-of-actual-awards method* is similar, except that actual awards are aggregated rather than target awards. Although over half of the survey plans use one of these approaches, the *financial results-based approach* has shown an increase in comparison to 2001 and 2005 survey findings.

Financial Results-Based Formula

As noted, the use of a funding formula based on financial results, which applies specific financial objectives designed to strengthen the link to company performance, is becoming more prevalent. Almost one-third (32%) of the survey respondents reported using this approach, compared to only 13% of companies in 2001 *(Exhibit 2).*

Exhibit 02. How Incentive Funding Is Determined



Companies that use this method will either create a bonus fund equal to a percentage of a financial measure (e.g., 3% of net income) or a percentage of a financial measure that exceeds a hurdle rate (e.g., 5% of net income in excess of an 8% return on net assets).

The most common performance measures used for plan funding are operating income and cash flow. Net income and pretax income are also used frequently *(Exhibit 3)*. In 2005, net income was the most common measure, and in 2001 EPS was the most commonly used measure in financial results-based formulas.

Exhibit 03. Measures Used in Incentive Plans With a Financial Results-Based Plan Funding Approach

	2010 Survey*	2005 Survey
Operating income	**29%**	**21%**
Cash flow	**28%**	**20%**
Net income	**22%**	**25%**
Pretax income	**22%**	**16%**

*Percentages total more than 100% due to multiple responses.

Almost one-half of companies that use a financial results-based formula allocate funds to business units based on performance (e.g., a corporate funding pool is allocated to business units based on business unit performance). The remaining companies are relatively evenly split between allocating at an individual level without first allocating to the business unit level and requiring business units to generate their own award pools.

When it comes to plan funding, it is less common to use a purely discretionary approach to determine the aggregate amount of award money (one unrelated to any established formula). For example, the board or management might look at the year's results and decide the company can afford to pay a total of $10 million in bonuses. Nine percent of companies reported using this approach in 2010, up from 5% in 2005, likely due to the difficulty of budgeting and setting performance expectations in the current economic environment.

"The use of a funding formula based on financial results, which applies specific financial objectives designed to strengthen the link to company performance, is becoming more prevalent."

Measuring Performance

In the drive to improve measurement and make compensation practices more effective, organizations continue to adjust their annual incentive plans by altering design features, usually in ways that are important to individual participants but don't involve a wholesale redesign. While cost is always a consideration for employers sponsoring these plans, typical design changes are made with an eye toward improving the line of sight between individual behavior and the organization's business objectives.

Consistent with our 2001 and 2005 findings, nearly nine out of 10 companies (89%) rely on two or more performance measures. Two-thirds of survey respondents (66%) reported that they currently use three or more performance measures.

While sales or revenue is the single most common annual incentive financial performance measure, four of the next five most common measures are earnings- or profit-based, and cash flow is now tied as the second-most prevalent performance measure (*Exhibit 4,* and *Exhibit 5* on page 11). Performance measures that show the largest increases in prevalence, compared to 2005, are cash flow and EBIT/EBITDA. The combination of sales or revenue with the other most common financial measures suggests that the drive for profitable growth is as strong as ever.

Use of Nonfinancial Performance Measures

Nonfinancial performance measures are often considered effective leading indicators of shareholder value creation and continue to gain in popularity (*Exhibit 6,* page 11). Due to the increasing prevalence of these measures, we have captured a wider range of metrics and categories.

Individual Performance and the Level of Performance Measurement

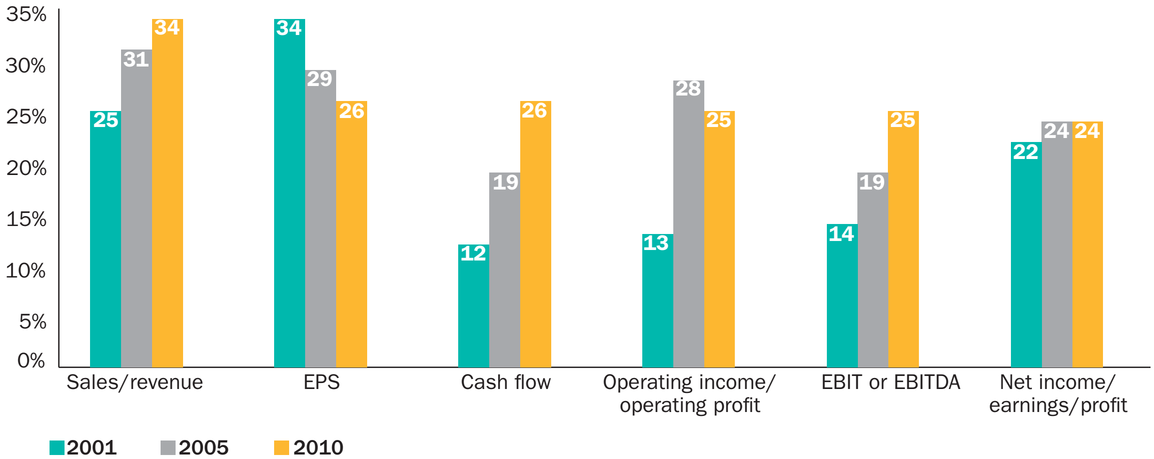
We asked survey participants to report the level at which performance is measured. While some organizations measure performance for the entire company, others measure performance at lower levels. In the latter approach, these companies possibly consider performance for each business unit or division, for the group (which includes several business units or divisions) and/or at the individual performance level.

Exhibit 04. Prevalence of Financial Performance Measures

	2010 Survey	2005 Survey
Sales/revenue	34%	31%
EPS	26%	29%
Cash flow	26%	19%
Operating income/operating profit	25%	28%
EBIT or EBITDA	25%	19%
Net income/earnings/profit	24%	24%
Cost/expense control/reduction	17%	—
Return on investment/return on invested capital (ROI/ROIC)	8%	7%
Return on equity (ROE)	7%	9%
Operating measures (e.g., operating margin)	7%	12%
Pretax income	5%	7%
Working capital	4%	—
Economic profit/economic value added (EP/EVA)	4%	3%
Gross margin	4%	—
Return on assets/return on net assets (ROA/RONA)	3%	4%
Total shareholder return	3%	—
Net operating profit after tax (NOPAT)	2%	—

Percentages total more than 100% due to multiple responses.

Exhibit 05. Historical Comparison of Most Prevalent Financial Performance Measures



A majority (61%) of the surveyed companies measure the CEO solely on corporate performance. In those cases where the CEO's award is based on more than corporate performance, it is usually based on a combination of corporate and individual performance. In short, the two most common CEO performance weightings and combinations are:

- 100% corporate performance
- 80% corporate, 20% individual performance

At lower levels in the organization, it is most common to base awards on two or more levels of performance. Performance measurement for non-CEOs generally depends on the employee's level within the organization.

At the group/sector executive level, common weightings and combinations are:

- 100% corporate performance
- 50% corporate, 50% individual performance
- 50% corporate, 50% group/sector performance

Common weightings and combinations for top business unit or division executives are:

- 25% corporate, 75% business unit/division performance
- 25% corporate, 25% business unit/division, 50% individual performance

Compared to our findings in 2005 and 2001, an increasing number of companies assign a specified weight to individual performance, especially below the CEO level *(Exhibit 7).* When an individual performance component is included in the CEO's measurement calculation, which is used in 32% of the sample, it is typically assigned a weight of 20%. Individual performance is used below the CEO level by about half of companies, and the typical weighting is 50% of the total incentive opportunity.

Exhibit 06. Prevalence of Nonfinancial Performance Measures

	2010 Survey	2005 Survey
Strategic objectives	**27%**	—
Safety/environmental	**17%**	—
Customer satisfaction	**16%**	**14%**
Team/department objectives	**16%**	—
Volume/production	**7%**	—
Employee satisfaction	**4%**	**4%**

Exhibit 07. Level of Performance Measurement

	% of Organizations Using Measures at Each Level			
	Corporate Measures	Group/ Sector Measures	Business Unit/Division Measures	Individual Measures
CEO	**93%**	—	—	**32%**
Corporate staff	**92%**	**13%**	**5%**	**55%**
Top group/sector executive	**85%**	**46%**	—	**42%**
Group/sector staff	**47%**	**79%**	—	**67%**
Top business unit/ division executive	**52%**	**15%**	**71%**	**49%**
Business unit/ division staff	**38%**	**5%**	**65%**	**52%**

Calculating the Award

Companies that use more than one performance measure must define how these measures will be combined to calculate an individual's bonus. There are three principal approaches:

- The most common method is the *additive approach,* which calculates performance separately for each measure and then adds the associated incentive awards to determine the final award. The prevalence of this approach is 69% and is consistent with prior survey results.
- 16% of respondents use a *multiplicative method* to calculate individual awards, representing an increase over our 2005 and 2001 results. Under this approach, performance under one measure is adjusted by performance under another measure. For example, a bonus calculated on EPS growth is multiplied by a factor based on a second performance measure to determine the bonus award.
- Similar to 2005 and 2001, fewer than 10% of respondents use the *matrix approach,* in which the levels of performance for two separate measures are each assigned an axis on a matrix. The employee's annual award, usually expressed as a percentage of the target amount, is determined by the intersection of the performance levels for the two measures.

"Similar to our previous findings, the use of circuit breakers and/or modifiers was reported by approximately one-third of respondents."

Circuit Breakers

When several measures are used to calculate bonuses, employees generally do not have to meet all the measures to receive some level of bonus. Some plans designate one or more measure(s) as a "circuit breaker" that essentially requires the achievement of a certain minimum level of performance to receive any award payout. Similar to our findings in 2005 and 2001, plans with some sort of circuit-breaker feature were reported by about one-third of respondents. The four most common corporate performance measures used as a circuit breaker, in order of prevalence, are EPS, EBIT or EBITDA, operating income and cash flow. Individual performance is used as a circuit-breaker measure among 9% of companies. For example, some plans are structured so that, no matter how well the company performs, an individual will not receive any bonus unless his or her performance is at least at some threshold level.

Modifiers

Some plans incorporate a final adjustment to the award calculation by applying a modifier. For example, an otherwise determined award can be increased or decreased by a certain percentage based on how well a certain goal is achieved. While this might be similar to the multiplicative approach, typically the modifier makes a smaller adjustment to a calculated award (e.g., an award calculated using the additive approach is modified by 105% if the modifier goal is achieved).

This practice is reported by 30% of survey respondents, versus 20% in 2005. Most often, this modification is based on an individual performance rating. Other common modifiers are EBIT or EBITDA and sales/revenue.

Performance Incentive Zones and Bonus Payout Ranges

The *performance incentive zone* describes the range of performance outcomes for which incremental increases in performance will result in incremental increases in bonus awards. Some plans place no hard limits on performance that can earn a bonus, creating unlimited upside opportunities. Other plans have thresholds and maximums, creating an incentive zone that represents all possible performance levels between the floor and the maximum or cap.

The *bonus payout range* describes the actual dollar amount that can be earned at each level in the performance incentive zone. Like performance incentive zones, payout ranges can be uncapped if there is no maximum. *Exhibit 8* shows an example of an 80% to 120% performance incentive zone, tied to a bonus payout range of 50% to 200% of target bonus. As this example illustrates, an employee in this plan would receive no bonus for performance up to 80% of target and could not earn more than 200% of his or her target bonus even if performance exceeded 120% of target performance.

The size of performance incentive zones and bonus payout ranges varies considerably among survey participants. The median performance incentive zone for most measures is 40%. In other words, the difference between threshold performance as a percentage of target and maximum performance as a percentage of target is 40%. For example, if the performance threshold is 80% of target, the maximum would be 120% of target.

The median bonus payout range is 150% for most performance measures, indicating a payout range, for example, of 50% at the threshold level of performance and 200% at the maximum level of performance.

The 2010 findings regarding performance incentive zones and bonus payout ranges are consistent with our 2005 and 2001 results. This suggests that companies are comfortable with the leverage inherent in their existing plans.

In previous years, performance incentive zones and bonus payout ranges varied slightly according to the performance measure evaluated. In 2010, the median incentive zones and payout ranges were generally the same for all of the most prevalent performance measures. *Exhibit 9* shows slight differences in the median ranges reported for sales/revenue, EPS, cash flow, operating income/operating profit, EBIT or EBITDA, and net income/earnings/profit.

Exhibit 08. Sample Performance Incentive Zone

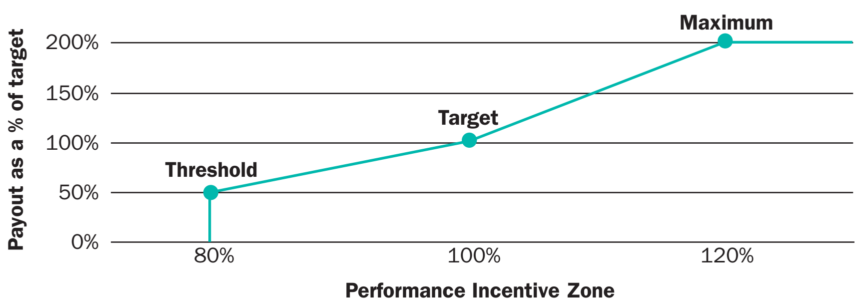


Exhibit 09. Performance Payout Zones

Median responses

	Performance as % of Target			Payout as % of Target		
Measure	**Threshold**	**Target**	**Maximum**	**Threshold**	**Target**	**Maximum**
Sales/revenue	**80%**	**100%**	**120%**	**50%**	**100%**	**200%**
EPS	**80%**	**100%**	**120%**	**50%**	**100%**	**200%**
Cash flow	**80%**	**100%**	**130%**	**50%**	**100%**	**200%**
Operating income/operating profit	**80%**	**100%**	**120%**	**35%**	**100%**	**200%**
EBIT or EBITDA	**80%**	**100%**	**120%**	**50%**	**100%**	**150%**
Net income/earnings/profit	**80%**	**100%**	**120%**	**50%**	**100%**	**200%**

Performance Expectations

“In 2010, the most common approach to establish a performance standard is expected business conditions.”

Companies must manage performance expectations by establishing standards to identify what constitutes target performance and to assess the extent to which the target has been achieved. In prior years, budgeted performance was the most widely used approach. In 2010, however, the most common approach to establish a performance standard was based on expected business conditions. As many companies use more than one method to set performance expectations, other common approaches include budgeted performance, year-over-year growth or improvement, investor expectations and performance relative to a peer group.

The approach used to establish performance standards usually varies, based on the performance measure. *Exhibit 10* shows the frequency with which various performance measures are used to set standards. As might be expected, the standards for financial measures are more likely to be based on budgeted performance or year-to-year growth than nonfinancial measures (e.g., customer satisfaction and employee satisfaction), which are often determined by a peer group comparison, or set by management or the board.

Exhibit 10. Factors That Determine Performance Expectations — by Performance Measure

	2010 Survey	2005 Survey
Determined by management/board based on business conditions	**58%**	**25%**
Based on budgeted performance	**49%**	**37%**
Year-to-year growth or improvement	**30%**	**27%**
Peer group performance or some other external standard	**15%**	**1%**
Achievement of strategic milestones	**11%**	**1%**
Based on expectations of investors	**10%**	**3%**
Timeless/absolute standard	**5%**	**1%**
Company’s cost of capital	**4%**	**—**

Payout Levels

We asked survey participants to report the level of bonus payouts made over the past five years, generally covering the period between 2004 and 2008. The pattern of payout levels follows the general economic environment *(Exhibit 11)*. The prevalence of payments in the target-to-maximum range was consistent during the 2004-2007 time frame. In 2008, there was a sizable increase in the prevalence of payments between minimum and target.

Overriding Plan Design

To address unforeseen shifts in the business climate, many companies maintain a degree of flexibility in the administration of annual incentive awards. Companies also want the flexibility to retain key people and keep high performers motivated in difficult times. Generally, for those positions not subject to IRC Section 162(m), companies have the right to adjust individual awards under the established plan formula — either paying an extra reward as a portion of a bonus not warranted by the level of performance or declining to pay a portion of the bonus that was earned based on the level of achievement.

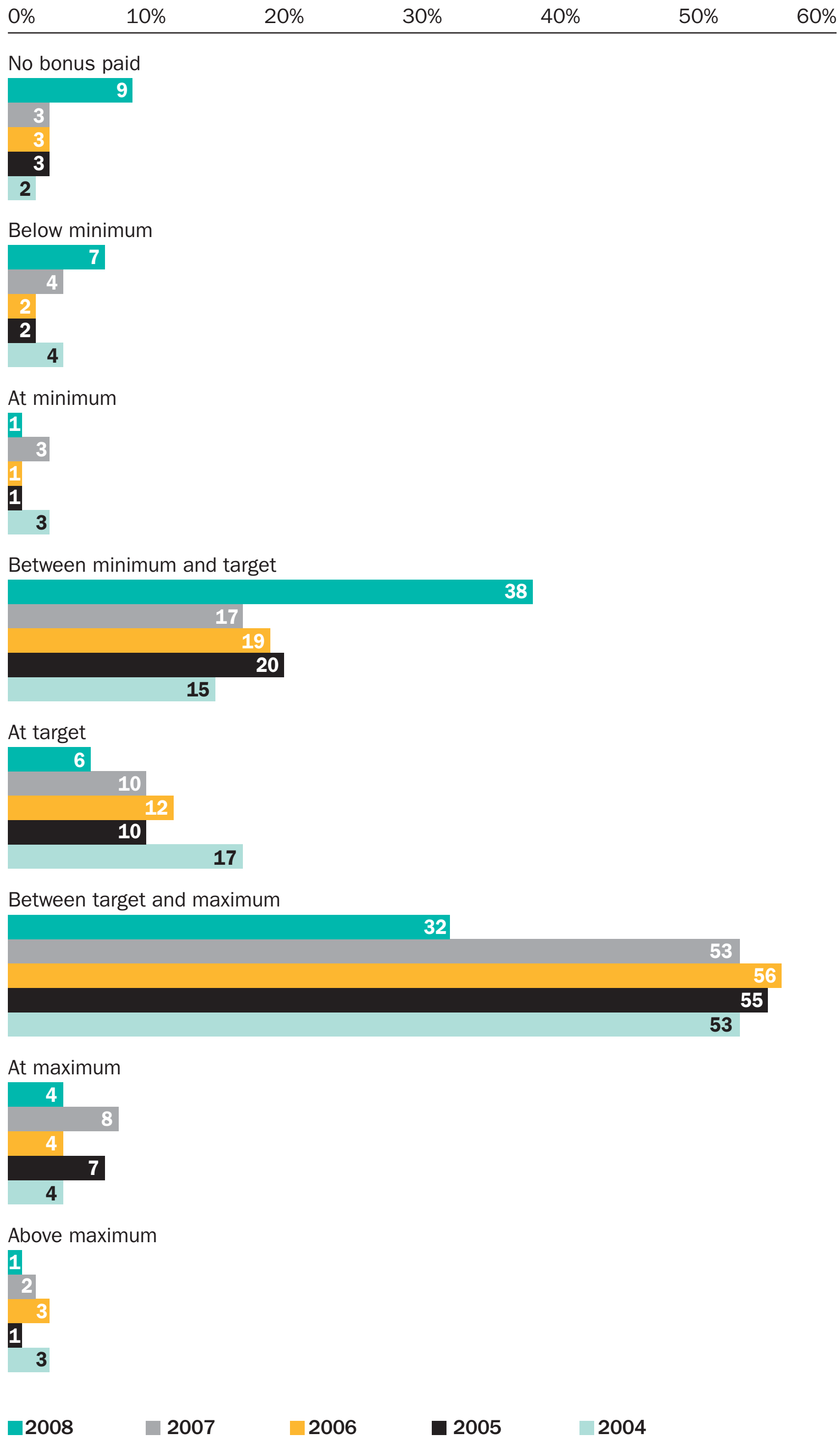
In this survey, we wanted to examine companies' experience with paying awards when performance thresholds were not reached. We learned that about 40% of survey participants had not been faced with such decisions in the previous five years because their organizations had met their thresholds each year.

Another 38% of participants reported they have not overridden the plan when threshold performance was not achieved. This finding suggests that more companies are deciding against overriding plan design. About 20% of survey respondents indicated they have overridden plan formulas and paid a portion of an award either to individuals or groups that did not meet the threshold level of performance. We found that this exception was usually made for a select few individuals rather than for the entire group.

Consistent with our findings in previous surveys, a much smaller percentage of companies (15%) have overridden their plans in the opposite direction, withholding a portion of an award that was earned under their formula. Again, if such an override does occur, it is usually done selectively for some participants.

Exhibit 11. Payout Levels Over Past Five Fiscal Years

% of companies paying out at each level



Award Payment

Size of Awards

The external market exerts considerable influence over incentive practices at individual companies as employers seek to balance their costs with their desire to attract and retain key talent. Of the companies using target bonuses, nearly all (91%) set target opportunities based on external market levels.

External Guidelines

Companies also often look at the bigger picture when trying to calculate the role bonuses will play in an overall compensation package. Again, this helps keep costs in line with objectives while ensuring the organization continues to attract, motivate and retain key talent.

We asked our survey respondents to tell us how competitive they would like to be in both base salary and total cash compensation (base salary plus annual bonus). *Exhibit 12* shows that most companies have targeted pay at the median for base salary and for total cash compensation. However, 26% of companies indicated that they target the 75th percentile for total cash compensation. (Note that target pay is different from actual pay levels.)

Exhibit 12. Desired Competitive Level of Each Compensation Component

	Base Salary	Target Total Cash
Below median	**2%**	**0%**
Median	**89%**	**51%**
60th percentile	**2%**	**5%**
75th percentile	**3%**	**26%**
90th percentile	**0%**	**4%**
Not specified	**2%**	**12%**
Other	**2%**	**1%**

Use of Discretion

The use of discretion in awarding incentive payments has become a common practice. Discretion is most likely to come into play with individual performance assessments, but payments can also be adjusted at the discretion of management or the board, or based on business circumstances. A few companies (5%) reported maintaining a special discretionary bonus fund outside the surveyed plans. Thirteen percent of companies reported that awards are not subject to discretion.

Payments in Cash

Most companies reported that their incentive payments are entirely or mostly in cash. About 5% of companies require an alternative, usually some combination of cash and stock. Thirteen percent of companies surveyed have a plan provision that allows bonuses to be paid totally or partially in stock. Among these organizations, it is slightly more common for the company to decide whether the bonus will be paid in stock, in lieu of cash. In some companies, however, participants are allowed to make that decision.

Deferred Payment Arrangements

One-third of the survey group offers plan participants the opportunity to defer payment for individual tax planning or other purposes. However, this practice has decreased significantly since 2001, when over two-thirds of companies reported offering deferral opportunities. This is most likely due to changes in U.S. tax rules, which impose additional restrictions on nonqualified deferred compensation.

"Most companies have targeted pay at the median for base salary and for total cash compensation."

Provisions for Employees Who Leave

Most companies have policies in place for employees who leave during the plan year or after the plan year has ended, but before bonus payments have been made.

If an employee leaves *during the plan year* due to disability, death or retirement, most companies pay a prorated portion of the award *(Exhibit 13).* If, however, the employee is terminated (for cause) or resigns during the plan year, more than nine out of 10 companies will not pay any bonus. If a person is laid off without cause (e.g., due to a downsizing), companies are divided among paying a partial award, no award or making decisions on a case-by-case basis, with the most common choice being no award.

If an employee leaves *after plan year-end* (but before bonus payments are made) due to disability, death or retirement, most companies will pay the full award *(Exhibit 14).* If the employee is terminated or resigns after plan year-end, companies are more likely to pay than if the termination occurred midyear. If the individual is laid off without cause after the end of the year, companies are again divided among partial award, no award or making decisions on a case-by-case basis, with the most common choice being to pay the full award.

For the most part, these practices are similar to those reported in the 2005 and 2001 surveys.

Exhibit 13. Bonus Treatment for Status Changes Occurring During Plan Year

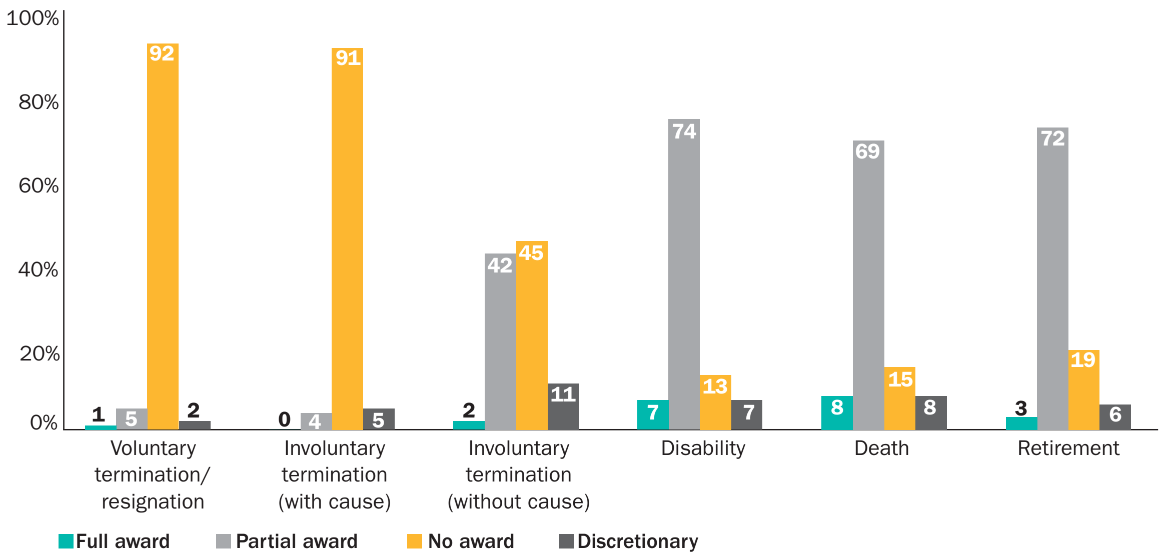
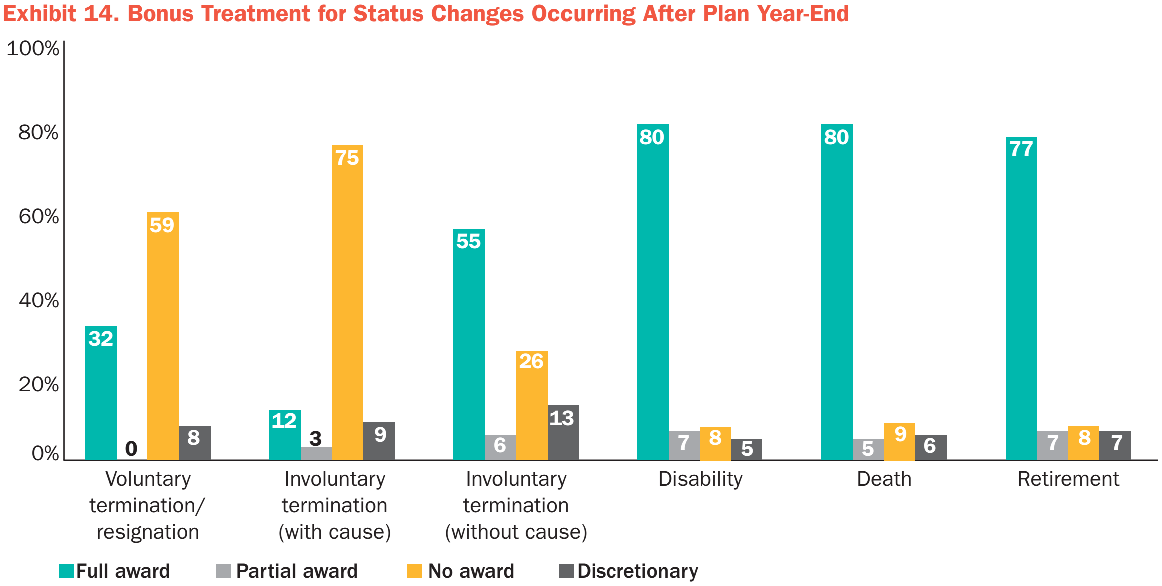
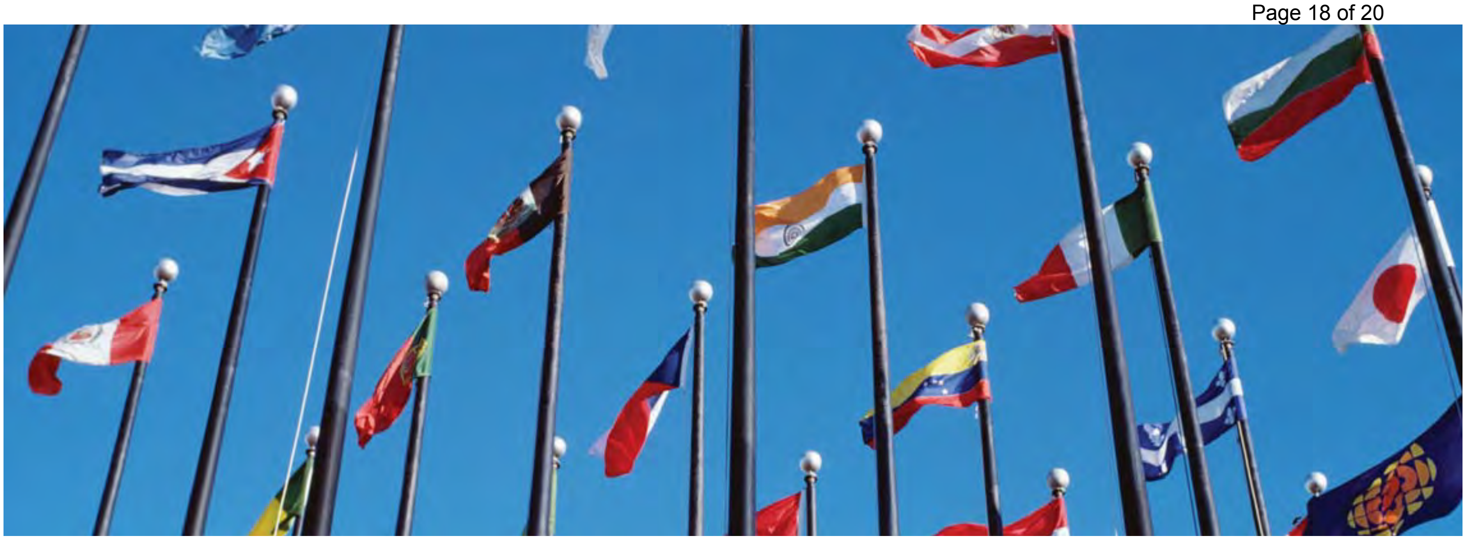


Exhibit 14. Bonus Treatment for Status Changes Occurring After Plan Year-End



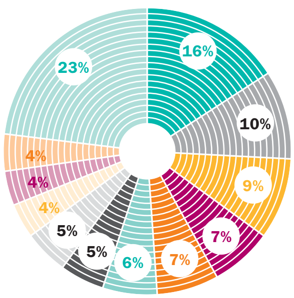


International Issues

About 60% of the companies surveyed include employees outside the home country (either the U.S. or Canada) in their surveyed incentive plan. Almost all of these companies (95%) use a similar plan design to deliver annual incentives to local and third-country national employees on a worldwide basis. Statutory restrictions and market practices are reasons cited by those companies that do not use a similar plan design in other countries.

Appendix

Exhibit A. Participants by Industry



- **16%** Energy services
- **10%** Insurance
- **9%** Food and beverage
- **7%** Financial services
- **7%** Oil and gas
- **6%** High tech
- **5%** Chemicals and gases
- **5%** Industrial manufacturing
- **4%** Pharmaceuticals and biotechnology
- **4%** Retail
- **4%** Telecommunications
- **23%** Other

Exhibit B. Participant List

Number of Participants: 212

Advanced Micro Devices
Agilent Technologies
AGL Resources
Agrium
AIG
Alberta Electric System Operator
Alberta Investment Management
Alliant Energy
Allstate
AMC Entertainment
American Airlines
American Commercial Lines
American Crystal Sugar
American Electric Power
American Family Insurance
American United Life
American Water Works
AMETEK
Anheuser-Busch
A.O. Smith
A&P
ARC Resources
A.T. Cross
Atomic Energy of Canada
AT&T
Automatic Data Processing
Avaya
Avista

BB&T
BC Transmission
Black Hills Power and Light
Blockbuster
Boeing
BOK Financial
BP
Bremer Financial
Brown-Forman

Campbell Soup
Canadian Broadcasting
Canadian Oil Sands
Canadian Pacific Railway
Capital Power
Carlson Companies
Carpenter Technology
CBS
CDI
Century Aluminum
CF Industries
Chevron
Chicago Mercantile Exchange
Chrysler
Chubb
CIGNA
Clearwire
Cobank
Comerica
ConocoPhillips
Constellation Brands
CPP Investment Board
Crown Castle

Dana
Del Monte Foods
Dick's Sporting Goods
Dominion Resources
Domino's Pizza
Dow Chemical
Dow Corning
DPL
Duke Energy
DuPont
Duquesne Light

Eaton
EMC
Energy Future Holdings
Entergy
EQT
Equity Residential Properties
Expedia
Exterran
ExxonMobil

First American
FirstEnergy
First Solar

Genzyme
GNC
Great Canadian Gaming
Greene Tweed

Hanesbrands
Harris
Hayes Lemmerz
H.B. Fuller
Henry Schein
Herman Miller
Hertz
Hewlett-Packard
Hexion Specialty Chemicals
Hoffmann-La Roche
Horizon Blue Cross Blue Shield of New Jersey
Hormel Foods
Hospira
Houghton Mifflin
Humana

IAMGOLD
IDACORP
IKON Office Solutions
IMS Health
Independent Electricity System Operator
Independent Order of Foresters
Insurance Corporation of British Columbia
International Flavors & Fragrances

J.M. Smucker

Kellogg
Kendle International
Kennametal
Koppers
Kroger

Land O'Lakes
Lenovo
Leprino Foods
Level 3 Communications
Liberty Property Trust
Life Technologies
Loto-Québec

Manulife Financial
Maple Leaf Foods
Marathon Oil
Massachusetts Mutual
McCormick
McDermott
McGraw-Hill
MDS
MDU Resources
Medicines
Methanex
M/I Homes
Milacron
Mine Safety Appliances
Molson Coors Brewing
M&T Bank
MTS Allstream
MTS Systems

National Bank of Canada
NAV Canada
New York Life
Nexen
Nicor
Nordstrom
Northeast Utilities
NRG Energy

Ontario Power Generation
Oshkosh Truck
Owens-Illinois

Pacific Gas & Electric
Pacific Life
Papa John's
Pennsylvania Real Estate Investment Trust
People's Bank
Petro-Canada
Plexus
PolyOne
Portland General Electric
Principal Financial
Prudential Financial

QUALCOMM

RGA Reinsurance Group of America
Royal & SunAlliance Canada

Schreiber Foods
Schwan's
S.C. Johnson
Securian Financial Group
Security Benefit Group
Shaw Group
Spirit AeroSystems
SPX
SRA International
Starbucks
Starwood Hotels & Resorts
Sunoco
Syncrude Canada

Takeda Pharmaceutical
Tarion
Teradata
Time Warner Cable
T-Mobile USA
Toro
Toronto Hydro Electric Systems
TransCanada
Trinity Industries
Tupperware

UniSource Energy
United States Steel
United Technologies
Unum Group

Valero Energy
Valmont
Vectren
Vermilion Energy Trust
Viacom
Viad
Vulcan Materials
VWR International

Warner Chilcott
Waste Management
Wells' Dairy
Western Digital
Western Union
Whirlpool
Williams Companies
Wm. Wrigley Jr.
World Color Press

Xcel Energy

Zale

About Towers Watson

Towers Watson is a leading global professional services company that helps organizations improve performance through effective people, risk and financial management. With 14,000 associates around the world, we offer solutions in the areas of employee benefits, talent management, rewards, and risk and capital management.

towerswatson.com

TOWERS WATSON

Compensation Strategy Recommendations
2013 Performance Measures and Weights

- **A balanced scorecard of earnings, safety and strategic measures**

Performance Category	2013	2012	2011	2010
Funding Measures	**75% EPS** **10% Safety** **15% Strategic Initiatives**	100% EPS	100% EPS	100% EPS
Funding Adjustments	**Zero Fatality Adj. (+7.5%)** **Culture (5%)**	Fatality Adj. (+/- 10%)	Fatality Adj. (+/- 10%)	Fatality Deduction
Allocation Measures				
Safety & Health	**N/A**	25%	30%	25%
Operations	**N/A**	25%	30%	25%
Regulatory	**N/A**	-	20%	25%
Strategic Initiatives	**N/A**	50%	20%	25%
The funding measures above would apply to all annual incentive groups				

Compensation Strategy Recommendations
2013 Company-Wide Annual Incentive Compensation
Zero Fatality Adjustment (+7.5%)

- **Zero Fatality Adjustment:**
  - **In the event AEP does not experience a fatal work related employee incident, the overall net composite score would increase by 7.5% of target for all employees**
    - **This changes the Fatality Adjustment used for the past two years to eliminate the potential negative impact of a fatality in favor of a positive adjustment for zero fatality years only**
    - **It changes the potential impact from a percentage of the actual score, to a percentage of target**
    - **It also changes the magnitude of the potential impact:**
      - **From +/- 10% of the actual score for officers to +7.5% of target,**
      - **From +/- 5% of the actual score for other employees to +7.5% of target, and**
      - **From - 10% of the actual score for employees in any business unit that experiences a fatality to no impact**

Culture Goal (Up to 5% Addition to Overall Score)

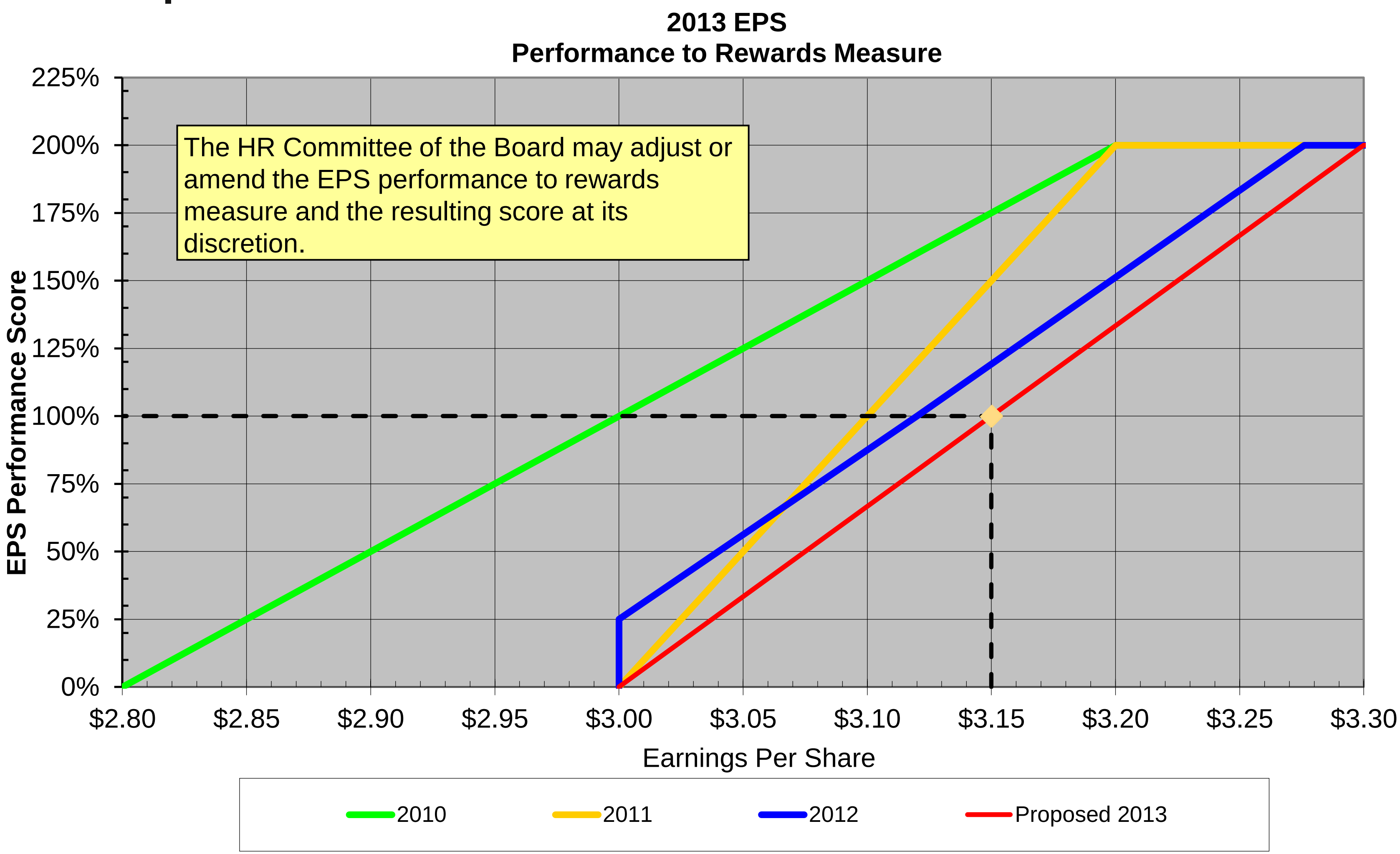
- **The linkage between a healthy organization culture and business performance is clear**
- **AEP will launch the cultural transformation by the end of Q1 to meet the following milestones:**
  - **Conduct 50 plus focus groups across business units and levels of employees by end of February**
  - **Analyze data to develop roadmap for Cultural Transformation with 2013 actions and communication campaign**
  - **Engage leaders at the February Leadership Summit and obtain personal commitments to action plans for ICP goals and 360 degree reviews**
    - Action plans for all participants (200% maximum score)
    - Action plans for 95% of participants (100% of target score)
    - Action plans for 90% or less of participants (0% score)
  - **Launch 2013 Roadmap in March to all employees outlining short-term and long-term actions in 4 focus areas:**
    - Strategic Direction
    - Leadership
    - Rewards and Recognition
    - Employee Engagement
- **Hold offsite meeting for Executive Council to gain commitment, ensure alignment, and create actions to support and drive the transformation of the culture**
- **Conduct focus groups in the last quarter to gauge progress and areas of focus for 2014**
  - **A progress assessment will be provided to the HRC**

Compensation Strategy Recommendations
2013 EPS Measure (75% weight)

- **Maximum Score:** EPS at or above $3.30 results in a 200% of target award pool
- **Target Score:** EPS of $3.15 results in a target award pool
- **Threshold Score:** EPS at or below $3.00 results in no award payout

	EPS Requirement	Award Score
Maximum Award	≥ $3.30	200%
Target	= $3.15	100%
Threshold	≤ $3.00	0%

Compensation Strategy Recommendations
2013 EPS Performance Requirement (75% Weight)



Compensation Strategy Recommendations
2013 Strategic, Operating and Safety Goals (25% Weight)

- **Repositioning Implementation Savings – 10% Weight**
  - **Maximum 200% score: achieve ≥ $225 million in O&M savings for 2013 and projected savings for future years**
  - **Target 100% score: achieve $200 million in O&M savings for 2013 and projected savings for future years**
  - **Threshold 0% score: achieve ≤$150 million in O&M savings for 2013 and projected savings for future years**
  - **In addition this measure includes a subjective component to reflect further repositioning of the growth businesses; the manner in which the repositioning was implemented, including open, honest and clear employee communications; and maintaining an appropriate balance of shareholder, employee and customer interests**
- **Safety Matrix – 10% Weight**
  - **This measure will have severity rate (50%), incident rate (40%) and contractor incident rate (10%) components**
  - **Maintaining AEP's safety culture remains a primary priority**

Compensation Strategy Recommendations
Strategic, Operating and Safety Goals (continued)

- **Competitive Business Development – 5% Weight**
  - **Grow, evolve the competitive business including trading, retail energy sales and services, and prepare to receive unregulated generation**
    - **AEP Energy EBITDA of $37 million with +/- 15% of target threshold (0% score) and maximum (200% score) points**
  - **Continued progress on Ohio corporate separation and pool termination**
    - **Obtain authorizations from FERC, KY, VA, WV and OH (on rehearing) that are sufficient to**
      1. **Complete the corporate separation of AEP Ohio,**
      2. **Transfer Amos 3 and the two Mitchell units to Kentucky Power and Appalachian Power, and**
      3. **Terminate the AEP Interconnection (Pool) Agreement, as of Jan 2014**
    - **Prepare and/or file all documentation required to execute corporate separation, including real estate transfer documents, assignments of contracts, applications for the reissuance of environmental or other governmental permits, and obtain a private letter ruling from the IRS confirming the tax-free nature of the transfer of assets**
  - **The effect of material uncontrollable events shall be considered for removal to avoid score impact.**
- **150% maximum <u>aggregate score</u> for all Strategic, Operating and Safety Goals**
- **No payout if EPS is less than threshold ($3.00 for 2013)**

Center for Advanced Human Resource Studies (CAHRS)

CAHRS Working Paper Series

Cornell University ILR School *Year* 2003

Is It Worth It To Win The Talent War? Evaluating the Utility of Performance-Based Pay

Michael C. Sturman
Cornell University

Charlie O. Trevor
University of Wisconsin-Madison

John W. Boudreau
Cornell University

Barry A. Gerhart
University of Wisconsin-Madison

CAHRS
Center for Advanced Human Resource Studies

CAHRS / Cornell University
187 Ives Hall
Ithaca, NY 14853-3901 USA
Tel. 607 255-9358
www.ilr.cornell.edu/CAHRS/

WORKING PAPER SERIES

Is It Worth It To Win The Talent War? Evaluating the Utility of Performance-Based Pay

Michael C. Sturman
Charlie O. Trevor
John W. Boudreau
Barry Gerhart

Working Paper 03 - 12

CORNELL ilr School of Industrial and Labor Relations

Is It Worth It To Win The Talent War? Evaluating the Utility of Performance-Based Pay

Michael C. Sturman
Management: Operations, Human Resources, and Law
School of Hotel Administration
Cornell University

Charlie O. Trevor
Department of Management and Human Resources
University of Wisconsin-Madison

John W. Boudreau
Center for Advanced Human Resources Studies (CAHRS)
ILR School
Cornell University
393 Ives Hall
Ithaca, New York 14853-3901
(607) 255-7785
jwb6@cornell.edu

Barry Gerhart
Department of Management and Human Resources
University of Wisconsin-Madison

September 2003

Abstract

While the business press suggests that "winning the talent war," the attraction and retention of key talent, is increasingly pivotal to organization success, executives often report that their organizations do not fare well on this dimension. We demonstrate how, through integrating turnover and compensation research, the Boudreau and Berger (1985) staffing utility framework can be used by industrial/organizational (I/O) psychologists and other human resource (HR) professionals to address this issue. Employing a step-by-step process that combines organization-specific information about pay and performance with research on the pay-turnover linkage, we estimate the effects of incentive pay on employee separation patterns at various performance levels. We then use the utility framework to evaluate the financial consequences of incentive pay as an employee retention vehicle. The demonstration illustrates the limitations of standard accounting and behavioral cost-based approaches and the importance of considering both the costs and benefits associated with pay-for-performance plans. Our results suggest that traditional accounting or behavioral cost-based approaches, used alone, would have supported rejecting a potentially lucrative pay-for-performance investment. Additionally, our approach should enable HR professionals to use research findings and their own data to estimate the retention patterns and subsequent financial consequences of their existing, and potential, company-specific performance-based pay policies.

Is it Worth it to Win the Talent War?
Evaluating the Utility of Performance-Based Pay

The ability to achieve competitive advantage through people depends in large part on the composition of the work force. This, in turn, is a function of who is hired, how they are developed, and who is retained—the latter of which is the focus of this study. Voluntary employee turnover can be either dysfunctional or functional for the organization, depending on who leaves (Boudreau, 1991; Boudreau & Berger, 1985; Hollenbeck & Williams, 1986; Trevor, 2001). Both low and high performers are generally more likely to leave an organization than are average performers (Jackofsky, 1984; Trevor, Gerhart, & Boudreau, 1997; Williams & Livingstone, 1994). Thus, organizations often will shed poor employees (functional turnover), but will also fail to retain star employees (dysfunctional turnover). It appears, however, that organizational practices can influence the performance distribution of leavers. Specifically, though high performers typically may leave the organization more often than do average performers, they do not necessarily do so. While research consistently reports that an organization's pay system affects the probability of voluntary turnover (Dreher, 1982; Gerhart & Milkovich, 1992; Griffeth, Hom, & Gaertner, 2000; Harrison, Virick, & William, 1996; Porter & Lawler, 1968; Schwab, 1991; Steers & Mowday, 1981; Trevor et al., 1997), the probability of high-performer turnover is particularly sensitive to the strength of the pay-for-performance link (Trevor et al., 1997). Consequently, organizations may be able to design compensation systems to enhance organizational value by targeting retention efforts at the dysfunctional high performer turnover.

This may in fact be increasingly happening as organizations in the United States and abroad are progressing toward linking pay more strongly to performance (Milkovich & Newman, 2002). Although many organizations have expanded their use of plans that reward team, business unit, and corporate performance (Milkovich & Newman, 2002), the predominant basis for pay-for-performance continues to be individual performance (IOMA, 2002; Hewitt Associates, 2002), and survey data indicate that companies believe individual pay-for-performance programs are effective (IOMA, 2002). While there are concerns about the wisdom of pay-for-performance (e.g., Kohn, 1993; Pfeffer, 1998), particularly for individual performance, research reviews find ample evidence that pay-for-performance is associated with higher performance at both the individual (Jenkins, Mitra, Gupta, & Shaw, 1998) and organizational levels of analysis (Gerhart, 2000). Such research, however, has not explicitly examined the mechanisms through which pay-for-performance plans affect individual behaviors to influence the organizational bottom line. One such mechanism involves pay-for-performance's effects on performance-specific turnover, and the associated costs and benefits that contribute to organizational financial performance.

The professional HR literature suggests that influencing the retention of high performers in particular is a crucial matter. Many articles cite the increasing difficulty in obtaining and keeping top talent (e.g., Bartlett & Ghoshal, 2002; Branch, 1998; Chambers, 1998; Rich, 1999). A report based on interviews of over 5,000 executives and managers (McKinsey & Company, 1998), for example, found that 65% of executives believed that they had insufficient talent in the ranks of their top 300 leaders and only 10% strongly believed that their companies retained most of their high performers. Even with the recent economic slowdown, organizations face increased pressures to attract and retain top talent in their most pivotal talent areas. The Bureau of Labor Statistics projects that, by 2010, the labor supply will grow by 17 million (Fullerton & Toosi, 2001) while labor demand will increase by 22.2 million (Berman, 2001), indicating that labor shortages will play increasing roles in the future. Moreover, even if a company is reducing employee headcount, voluntary attrition is often the first and most attractive option (Sherwyn & Sturman, 2002). Each of these circumstances highlights the potential benefits of managerial investments that particularly facilitate top-performer retention.

Few would debate the merits of a performance-based pay practice that, all else equal, resulted in greater retention of high performers. Unfortunately, all else is far from equal when changing an organization's pay systems. Because such changes will affect total labor costs, individual employee pay levels, and subsequent employee behaviors, the critical question becomes one of whether the benefits of such a practice outweigh the costs. We propose that while the potential retention benefits of incentive pay have been recognized, they have yet to be quantified in dollar terms. Moreover, researchers have failed to adequately address actual costs of performance-based bay. Our goal here is to provide the first empirical cost-benefit assessment of the viability of performance-based pay. Our approach should contribute to the pay-for-performance literature by specifying the circumstances that affect the success of pay-for-performance plans.

Our results should also contribute to practice, as the likelihood that HR professionals would apply the research findings to their own organizations should increase if these professionals are provided with a viable technique for doing so. In this paper we demonstrate such a technique. The employee movement utility model of Boudreau and Berger (1985) provides the means to evaluate the dollar value implications of various pay-for-performance strategies, which we illustrate with a step-by-step application to a published turnover and pay-for-performance article. In doing so, we (a) demonstrate how organizational representatives can use research findings, publicly available compensation and turnover data, or their own data to diagnose, inform, and evaluate their own company-specific incentive pay decisions; and (b), demonstrate that this technique will often provide different conclusions from typical decision models that use only traditional cost or accounting analysis.

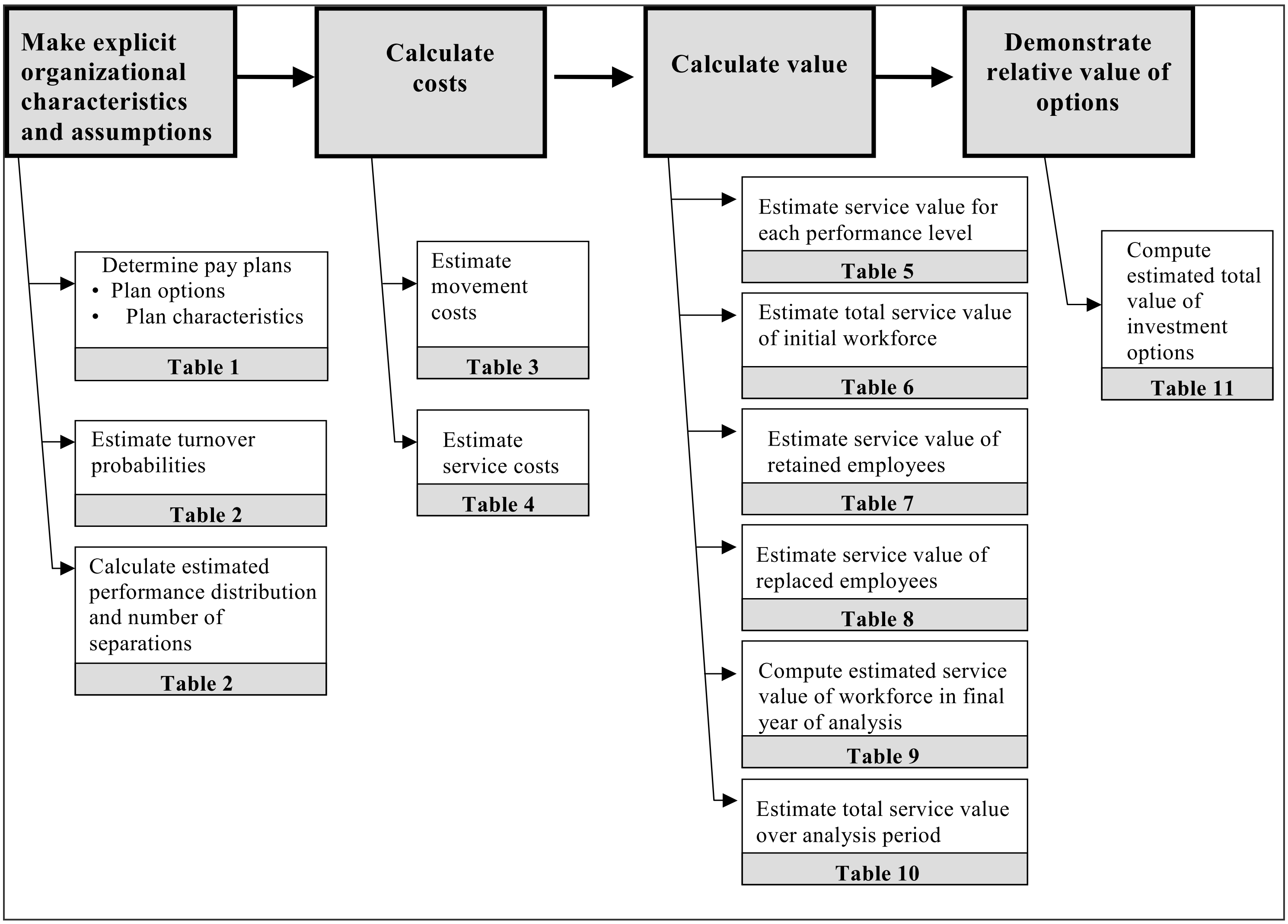
Utility Analysis Applied to Pay Decisions

Utility analysis is a tool for cost-benefit analysis that helps quantify the impact of human resource interventions (Cascio, 2000). While utility analysis has been applied to numerous human resource program areas, most applications have concentrated in the areas of employee selection and training (Boudreau & Ramstad, 2003b; 1999; Boudreau, 1991). The Boudreau and Berger (1985) framework represents one of the few applications to employee retention. Klass and McClendon (1996) used that framework to examine the pay policy decision of whether to lead, lag or match the market. They gathered parameter information from published studies and simulated effects on employee separation and offer acceptance patterns. Results for bank tellers suggested that a lag policy produced higher payoffs, although "leading the market" (paying higher than the average) did enhance retention and attraction of top candidates. The authors noted that these results did not necessarily suggest using a particular pay policy, and showed how simulated reductions in citizenship behavior due to low pay might change the results. This was an important initial application of employee movement utility principles to decisions about pay.

In this paper, we focus on a different type of pay decision – how to allocate pay increases across employees at different performance levels. Trevor et al. (1997) found that pay policies providing greater pay growth for high performers (and less for low performers) substantially increased retention among high performers, encouraged separation among low performers, and thus increased the value of the work force. This is an appealing prospect, but it is unclear whether the enhanced workforce value would offset the cost associated with such a reward system. Such costs are quite apparent using traditional accounting or behavioral costing models, but such models have limited ability to reflect effects on workforce value; furthermore, little data exists on the actual implications of these limitations (Boudreau & Ramstad, 2003a; 2003b). It is also unclear to what extent the enhanced workforce value would depend on such factors as the pay policy specifics, the retention pattern, and the variability in performance. The Boudreau-Berger utility framework provides a method to address these questions.

Using the Boudreau and Berger (1985) separation/acquisition utility model, our paper presents a model that captures the value associated with employee separations (turnover) and acquisitions (hires) over time. The model estimates three components in each time period: (a) movement costs—the costs associated with employee separations and acquisitions; (b) service costs—the pay, benefits, and associated expenses required to support the work force; and (c) service value—the value of the goods and services produced by the work force. The dollar-valued implications of a given pay plan, and of the subsequent separation and acquisition patterns over time, are estimated by subtracting the movement costs and service costs from the service value (i.e., subtracting the pay plan's costs from its benefits). Figure 1 shows the steps necessary to compute this estimate and the tables we employ here to illustrate these steps.

Figure 1
Flow Chart of Utility Analysis Procedure



The Illustrative Case Study

We illustrate our approach using a scenario in which a hypothetical company is considering implementing a pay-for-performance plan at the end of the year 2003. We assume that the company does not currently relate pay to performance, so under the current strategy all employees would receive the same pay increases over time. We compare the effects of this strategy with those of two alternative strategies that place different emphases on pay-for-performance. We choose to evaluate the implications of the three possible approaches over a four-year period (2004 to 2007). Thus, because pay-for-performance affects turnover differently at different levels of performance (Trevor et al., 1997), the 2007 workforce would reflect a different performance distribution under each of the three pay strategies. By calculating the movement costs, service costs, and service values from 2004 to 2007, we can estimate the cumulative effects of the pay strategies over the four-year period.[1]

We used a number of spreadsheets to make the necessary calculations, with each spreadsheet corresponding to a table in this paper. The spreadsheets are available from the lead author upon request, although the descriptions we provide here should be sufficient for many readers to create their own. We also make a number of assumptions to perform the necessary calculations. These assumptions are all based on published research (e.g., Trevor et al., 1997) or publicly available data (e.g., BLS, 2002). First, we draw directly from the Trevor et al. (1997) study to estimate (a) the relationship between pay growth, performance, and turnover that is captured in their survival analysis (see Appendix) and is used to calculate the turnover probabilities at each performance level under each pay strategy; (b) the baseline turnover probability necessary to compute those turnover probabilities that are specific to each performance level-pay strategy combination; and (c) the performance distribution at the beginning of our utility analysis timeframe.

It should be noted that the Trevor et al. (1997) data are from all 5,143 exempt employees hired by a large petrochemical organization between 1983 and 1988. Furthermore, Trevor et al. (1997) examined the effects of various strengths of pay-for-performance relationships based on archival data on individuals' performance and pay levels; they did not specifically manipulate the pay-for-performance link as part of either an experimental or quasi-experimental design. Nonetheless, these data represent a wide variety of exempt jobs over several years, and the results provide valuable insight into the relationships between turnover, pay, and performance. Thus, the results of the Trevor et al. (1997) study are useful for our purpose of illustrating our technique.

Second, we use published surveys (WorldatWork, 2002; BLS, 2002) to help generate realistic pay strategies, determine starting average pay levels, and estimate benefit costs. Finally, we employ the results of published research studies to help provide realistic estimates of the cost of turnover (e.g., Solomon, 1988; Johnson, 1995) and the value of different levels of employee performance (Becker and Huselid, 1992; Boudreau, 1991; Cascio, 2000; Schmidt and Hunter, 1983). We describe the rationale for our assumptions and suggest how professionals might apply each rationale or gather their own data to customize the application for their organizations. Thus, our demonstration is intended (a) to provide information on the value of pay-for-performance plans and the extent that they should ultimately lead to improved organizational financial success; and (b) to enable others to use the method with their own company's data, new research findings, and/or their own estimates to create company-specific evaluations to facilitate their own decision-making regarding the implementation of pay-for-performance policies.

Pay-For-Performance Plans and Performance-Specific Turnover

Step 1: Specify the Pay-for-Performance Options

As is evident in Figure 1, the first major phase in estimating the costs and benefits of performance-based pay is to make explicit the relevant organizational characteristics and assumptions. The initial step within this phase is to specify the pay policy scenarios to be considered. The two key parameters needed are: (a) the current pay level in each performance category for the employees to be considered; and (b) the relationship between pay growth and performance levels (usually expressed in terms of the percentage increase awarded for each performance level). For this second parameter, we constructed three hypothetical, but realistic, performance-based pay strategies. Because we intend to provide a broad range of potential outcomes, within which most particular organizational results should fall, the strategies were chosen to range from conservative to aggressive in terms of the pay-for-performance link. In terms of performance categories, we adopted the nine performance-rating categories used by Trevor et al. (1997), which range from 1.0 (lowest performance) to 5.0 (highest performance) in 0.5 increments, because this will facilitate using other aspects of the Trevor et al. situation as an illustration. Trevor et al. (1997) created the nine categories by computing average performance over time from a rating system in which "The performance scale ranged from 1 = lowest to 5 = highest, with the five categories representing levels of consistency in meeting and exceeding the basic requirements of the job" (p. 49). Professionals adopting our utility analysis framework should change the performance categories to reflect their own performance assessment approach.

Table 1
Pay Strategies and Estimated Four-Year Pay Levels for Each Strategy

Performance Ratings:	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Pay Increase for Pay Strategy 1	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**	**4%**
Pay Increase for Pay Strategy 2	**4%**	**4%**	**4%**	**4%**	**4%**	**5%**	**6%**	**7%**	**8%**
Pay Increase for Pay Strategy 3	**0%**	**1%**	**2%**	**3%**	**4%**	**5%**	**6%**	**7%**	**8%**
2003 Average Pay	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**	**$47,983**
Pay Strategy 1: No pay/performance link									
2007 Average Pay	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133	$56,133
Pay Strategy 2: Pay for performance e link for above average performer									
2007 Average Pay	$56,133	$56,133	$56,133	$56,133	$56,133	$58,324	$60,577	$62,896	$65,280
Pay Strategy 3: Pay for performance link for all performers									
2007 Average Pay	$47,983	$49,931	$51,938	$54,005	$56,133	$58,324	$60,577	$62,896	$65,280

Note: Data provided by the user **are in bold.**

The details of our three illustrative pay-for-performance plans are shown in Table 1. Pay strategy 1 gives all employees the same average pay increase, regardless of performance level. Data suggest that current pay increases average 4% (WorldatWork, 2002; BLS, 2002; Peck, 2002), so we used this value for all performance categories in pay strategy 1. Pay strategy 2 creates a pay-performance link (i.e., larger pay increases as performance improves) for performers above the middle "3.0" rating, and average pay increases (i.e., 4%) to those rated

3.0 and below. Pay strategy 3 maintains the positive reinforcement of pay strategy 2, and extends the pay-for-performance link to those below the middle rating (i.e., smaller pay increases as performance worsens). Thus, pay strategy 1 provides no performance link, pay strategy 2 is more aggressive, and pay strategy 3 is the most aggressive.

As noted above, in addition to the pay raise strategy, step one requires the setting of an initial pay level upon which the pay strategies will be applied. Because our example involves evaluating the pay-for-performance strategies for white-collar employees, we used the Bureau of Labor Statistics (BLS, 2002) estimate of average 2001 white collar (non-sales) pay, adjusted for the average salary increases of exempt workers for 2002 and 2003 (WorldatWork, 2002). This ultimately yielded a pay level of $47,983 for the year 2003.[2] For illustration, we simply assigned this same initial pay level to every performance category. Then, applying the percentage increase associated with each pay strategy and extrapolating for four future years, we projected the resulting performance-specific pay levels for the year 2007, as reported in Table 1.

In actual organizations, of course, the current pay levels would be available from company records. The same forward-projection method can be used based on these initial values. With observations of real data, it seems likely that initial pay levels will vary across performance categories, reflecting past pay policies, demographics, and performance distributions. While quite easy to observe in practice, pay-performance distributions are likely quite variable, so no obvious method exists to simulate them for our example. Our decision to begin with a uniform pay distribution across categories simplifies the presentation but does not otherwise reduce the generalizability of our approach.

Step 2: Determine Turnover Probabilities

The second step in the making explicit of organizational characteristics and assumptions (i.e., the first major phase in Figure 1) is to estimate the probability of separation at each performance level for each pay strategy. This step defines the key link between performance-based pay and workforce composition. For practitioners, this may represent the most novel element of the model, yet we believe it is quite feasible. We describe several methods for estimating these probabilities.

Estimation using existing research literature

Perhaps the most straightforward approach is to refer to existing empirical findings. For our hypothetical example, we use the performance level/pay strategy specific separation results generated by Trevor et al. (1997). Professionals employing utility analysis likely would prefer to access separation probabilities from a study of an employee population that resembled their own employees in terms of occupations, industry, and demographics. To date, however, the Trevor et al. (1997) study is the only published work from which the performance level/pay strategy specific separation probabilities can be estimated. While future research providing such information for different employee populations would be helpful, in their absence, the Trevor et al. (1997) results offer a useful starting point.

Estimation using organizational data

A second option for generating the performance level/pay strategy specific separation probabilities that are necessary for the cost-benefit analysis would be for professionals to estimate them using their own organization's data. In most companies, separation rates are customarily calculated for entire job categories and are seldom broken down by performance levels. Even when separation rates are reported by performance levels, they are rarely further broken down to reflect pay growth. Yet, if yearly individual-level information on performance, pay level, and separation is available, it can rather easily be converted into the required separation probabilities estimates.

First, professionals can compute each employee's average pay growth and average employee performance over a specified time period (e.g., over the last three years). These relatively continuous data can then be used to slot employees into performance level/pay strategy categories, such as Table 1's 27 categories that were created from all combinations of three pay strategies and nine performance levels. This approach would be repeated for all appropriate performance level and pay growth combinations, thus yielding counts of employees that fit each category. After compiling these counts, the second step would be simply to divide each category's number of voluntary separations by the number of employees in that category. This would yield the estimates of the separation probabilities specific to each performance level/pay strategy combination that are necessary for conducting the cost-benefit analysis of performance-based pay.

While relatively simple to describe, estimating category-specific separation probabilities from one's own organization involves two potentially difficult hurdles. First, to estimate the separation probabilities with any degree of reliability, there must be an adequate number of employees in the categories of interest. If the number of employees in a given category is low, then the resultant average rate of turnover may be strongly influenced by sampling error rather than reflecting an accurate estimate of that category's true turnover likelihood (e.g., a category with one employee mandates an unrealistic separation probability estimate of either one or zero). Thus, the HR professional or I/O psychologist must be working with relatively few categories and/or with large employee populations. A second serious problem with the approach described above is that it will produce separation probabilities that are likely to be confounded by other factors that are related to turnover, performance, and pay growth, such as pay level, age, gender, and tenure with the organization. Hence, though computing performance level/pay strategy specific separation probabilities for one's own organization is relatively simple, its value may be limited.

Fortunately, two statistical methods are available for dealing with the confounding and employee-per-category problems. While both of these methods require a statistical package and reasonable statistical sophistication, I/O psychologists may well have been exposed to one or both of the methods. If not, their training still may well have provided them with a methodological foundation sufficient to allow them to learn the techniques, particularly with the advances in user-friendly statistical software. Alternatively, HR professionals or I/O psychologists could simply hire a consultant to assist with the analyses.

Logistic regression and survival analysis can be used to estimate separation probabilities. Both explicitly account for the potential confound described above by statistically controlling for the effects of these other variables. The analyses yield partial coefficients that are net of the effects of the potentially confounding variables. The partial coefficients are then used to compute separation probabilities needed to conduct the cost-benefit analysis. Both methods also exploit the full range of the relatively continuous salary growth and performance data, rather than requiring pre-established categories that necessarily result in a loss of information. Logistic regression estimates the probability of separation over a specified time period. Survival analysis (Kalbfleisch & Prentice, 1980) computes the probability of survival (i.e., not separating) over a specified time span, and accounts for the length of time an individual stays before leaving the organization. In other words, survival analysis specifically models how long an individual remains with an employer before leaving, whereas logistic regression models whether a person leaves or not. While both methods are appropriate for estimating the separation probabilities specific to the performance level/pay strategy combinations of interest, each offers advantages under certain circumstances (for a complete discussion of this issue, see Morita, Lee, & Mowday, 1993). Our Appendix describes the use of survival analysis to calculate the required separation probabilities that are specific to each of our performance level/pay strategy combinations.

<u>Estimated separation probabilities for the example.</u>

For our example, we used the survival analysis results reported in Trevor et al. (1997), which estimated a survival model from data on a sample of exempt employees in one organization. The analysis produced a mathematical function describing survival probabilities as a function of salary growth and performance, which we present in the Appendix. Substituting a specific salary growth amount and performance level into the equation produces an estimated survival probability that is appropriate for that performance level and salary growth combination. Thus, we used the equation reported in Trevor et al.'s (1997) Table 4 (p. 54) to compute the separation probability (1.0 minus the survival probability), for each performance category under each pay strategy, at the end of our example's 4-year period. The estimated separation probabilities are presented in the top part of Table 2.

Table 2

Turnover Probabilities, and Estimate Number of Retained and Replaced Employees

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Number of employees	**60**	**97**	**1171**	**1090**	**1667**	**672**	**317**	**46**	**23**	5143
Turnover Probabilities[1] (Probability of leaving the organization by 2007)										
Pay Strategy 1	**0.96**	**0.65**	**0.38**	**0.25**	**0.21**	**0.22**	**0.27**	**0.41**	**0.66**	
Pay Strategy 2	**0.96**	**0.65**	**0.38**	**0.25**	**0.21**	**0.14**	**0.11**	**0.11**	**0.14**	
Pay Strategy 3	**0.99**	**0.88**	**0.60**	**0.35**	**0.21**	**0.14**	**0.11**	**0.11**	**0.14**	
Retained Employees (2007)										
Pay Strategy 1	2	34	726	818	1317	524	231	27	8	3687
Pay Strategy 2	2	34	726	818	1317	578	282	41	20	3818
Pay Strategy 3	1	12	468	709	1317	578	282	41	20	3428
Replaced Employees (2004 - 2007)[2]										
Pay Strategy 1	58	63	445	273	350	148	86	19	15	1457
Pay Strategy 2	58	63	445	273	350	94	35	5	3	1326
Pay Strategy 3	59	85	703	382	350	94	35	5	3	1716

Notes: 1. These values were based on analyses from the Trevor et al. (1997) study. Those performing their own analyses would need to complete the table with their own company-specific data, or use approximations from the Trevor et al. results. See the Appendix for how we used the Trevor et al. results to obtain our values above.
2. Recall that we are evaluating the effects of the different pay policies going into effect at the end of 2004. Thus, while our data are based on the state of the workforce at the end of 2003, we are evaluating the effects of the programs in 2004-2007.
3. Data provided by the user **are in bold.**

We caution that our use of the Trevor et al. (1997) survival analysis provides reasonable separation probability estimates, rather than definitive ones. It is certainly probable that other factors could also influence the probability of turnover. For example, equity theory suggests that even when high performers receive the same pay increase (such as under Pay Strategy 2 and Pay Strategy 3), their turnover likelihoods may differ as a function of how referent others (e.g., low performers) are compensated. Our approach does not take this into consideration. Thus, the reader should keep in mind the imperfections associated with relying on any single study, model of turnover, or data set to estimate turnover probabilities.

Step 3: Determine Performance Distribution and Number of Separations

So far, we have established the pay increase that individuals in each performance level will receive under the different pay policies, and we have subsequently established the separation probabilities for each performance level/pay strategy category. Next, we need to project the number of separations in each performance level/pay strategy category over time. We specified our initial hypothetical employee group (those at the end of year 2003) to mirror in size and performance distribution the 5,143 employees analyzed by Trevor et al. (1997), which is shown in Table 2 (in actual organizations, the initial number of employees in each performance category would be identified through a straightforward count). We then multiplied the initial number of employees in each performance level/pay strategy category by the appropriate separation probability. Table 2 presents the resultant category-specific numbers of employees that separated (and will need to be replaced) and employees retained.

At this point, a traditional analysis of total separations would likely lead to a decision to adopt pay strategy 2, the moderately-aggressive policy through which performers above the midpoint receive higher pay increases. As Table 2 indicates, the number of separations over the four-year analysis period is 1,326 for pay strategy 2, while it is 1,457 for pay strategy 1 and 1,716 for pay strategy 3. Based only on separation rates, pay strategy 3 seems the least attractive policy. However, such conclusions are simplistic and superficial from a cost/benefits perspective; a more sophisticated and meaningful inference regarding the implications of the three pay strategies requires an analysis incorporating critical financial data.

Estimating the Cost of Pay-For-Performance Plans

Step 4: Determine Movement Costs

In steps one through three, we specified the pay-for-performance options, the estimated separation probabilities, and the subsequent numbers of separations and necessary replacements from each performance level/pay strategy combination. Hence, one key financial outcome to be considered is the projected cost of employee movements into and out of the workforce under each pay policy. As we see in Table 2, relative to the retention effects of simply providing everyone with the same salary increase (pay strategy 1), pay strategy 2 reduces overall separations, while pay strategy 3 increases them. We next translate these projected separations and replacements into financial costs.

We refer to the combined costs of employee separations and replacement acquisitions as movement costs. These costs include direct expenses, such as separation costs (e.g., exit interview, separation pay), replacement costs (e.g., advertising, travel expenses, interviewing and testing candidates), and training costs (e.g., informational literature costs, paying trainers). Movement costs also include indirect expenses, such as the lower productivity of new employees as they learn the job, time spent by managers having to supervise new employees more directly, and diminished productivity of veteran employees as they mentor and help new employees (Cascio, 2000). While such costs are not standard elements of traditional accounting systems, organizations increasingly employ software and reporting algorithms that calculate such metrics as turnover costs, costs per hire, etc. If these are available, one can simply multiply the relevant cost by the number of separations and/or replacements that emerge under each pay strategy.

Data available to calculate movement costs varies widely across companies. When movement costs are not readily available from the organization, one can turn to research. For example, Solomon (1988) suggested that movement costs range from 1.5 to 2.5 times the annual salary paid for a job (Solomon, 1988), while Johnson (1995) suggested that movement costs range from 93% to 200% of the position's salary. In our example, we estimated the movement cost associated with each separation as two times the average salary of all employees in the year of the separation (note that average salary will vary according to pay strategy). We also assumed that each separation is replaced, and thus we combined all separation and acquisition costs into a single estimate labeled movement costs. Should replacement not be expected, such as during a downsizing, separation cost estimates should be applied to the number of separations, and replacement acquisition costs should be applied to the number of replacements (Boudreau & Berger, 1985).

Table 3 provides the necessary information to estimate movement costs for our example. At the top of the table is the workforce's average salary in 2003 and in 2007 under each of the three pay strategies. As noted above, we multiplied this salary by 2.0 to estimate the average movement costs for each separation, which is shown for years 2003 and 2007. We then subtracted the 2003 average movement cost from the 2007 average movement cost and divided by four to get yearly movement cost increase, which we added to the 2003 average movement cost to get the 2004 average movement cost. This was added to the 2007 average movement cost and the sum was divided by two to compute the average (2004-2007) movement cost per separation. Table 3 also provides the total projected number of separations/replacements from Years 2004 to 2007, which were calculated in Table 2. Total movement costs for each pay strategy over the four-year period were then calculated by multiplying each pay strategy's total number of projected separations/replacements by each pay strategy's average movement cost per separation/replacement.

Table 3

Estimated Four-Year Movement Costs Under Different Pay Strategies

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Salary			
2003	$47,983	$47,983	$47,983
2007	$56,133	$56,914	$55,966
Movement Cost Multiplier (cost of separation as multiple of salary; same for all three Pay Strategies)	**2.0**		
Average Movement Costs (per separation)			
2003	$95,966	$95,966	$95,966
2007	$112,266	$113,828	$111,932
Yearly Increase in Average Movement Cost	$4,075	$4,466	$3,992
2004 Average Movement Cost	$100,041	$100,432	$99,958
Average Movement Cost (2004 - 2007)	$106,154	$107,130	$105,945
Number of Separations	1,457	1,326	1,716
Total Movement Costs[1]	$154,666,378	$142,054,380	$181,801,620

Notes: 1. Total Movement Costs were calculated assuming a linear growth in movement costs and an equal number of separations in each year. Thus, Total Movement Costs could be calculated as the number of separations times the average 2004 - 2007 movement costs. For simplicity, we assumed a constant rate of movement cost increase over time. This could easily be modified if an organization projected very significant increases or decreases in costs per movement in a given year, but such large discontinuities seem unlikely.
2. Data provided by the user **are in bold**.

Table 3's total estimated movement costs were $154.67 million, $142.05 million, and $181.80 million for pay strategies 1, 2, and 3, respectively. Compared to pay strategy 1 (giving equal pay increases to everyone), the turnover reduction associated with the policy of linking pay and performance for high performers (pay strategy 2) saves $12.61 million in movement costs over four years. Linking pay and performance for both high and low performers (pay strategy 3), however, creates additional separations among low performers and thus incurs four-year movement costs of $27.13 million and $39.75 million more than those incurred through pay strategies 1 and 2, respectively.

Some of these costs would be evident with standard accounting tools, to the extent that they represent "out-of-pocket" costs such as fees to search firms or consultants providing exit interviews. However, as mentioned above, many of these costs (e.g., staff time spent in processing separations and acquisitions) are "opportunity costs," and only a portion of these savings (costs) would be recorded by the accounting system. Thus, our analytical approach offers the advantage of a more complete cost analysis for incentive pay strategies. Still, movement costs represent only one of the crucial financial implications of using pay-for-performance to manage performance and turnover. Hence, we next address the pay strategies' substantial implications for differences in costs associated with pay levels, benefits, and other service costs.

Step 5: Estimate Future Service Costs

Service costs are the total costs required to retain and support the work force, and thus include pay and benefits (Boudreau & Berger, 1985), the latter of which is typically the largest service cost component other than pay. In some cases, service costs may vary with employee performance. For example, there may be significant bonuses or stock options, or higher performers may use significantly more materials or resources than lower performers. In these cases, which would tend to be of more relevance in executive populations, such variability in service costs should also be taken into account. Absent such factors, estimating service costs simply involves adjusting projected salary levels upward to reflect additional service costs (i.e., benefits), multiplying the resulting values by the number of employees in each year, and summing the products across years. Because we define total service costs as salary plus benefits in our example, we estimate each year's service costs by estimating the ratio of total remuneration (employee benefits plus salary) to salary, and then multiplying this ratio by projected salary levels under each pay policy.

In Table 3 we had established, for each pay strategy, the average salary levels for the full work force in 2003 and 2007. Because we assumed that benefits were 37% of salary (U.S. Department of Labor, 2001), we multiplied Table 3's average salary levels by 1.37 to reflect the

2003 and 2007 average service costs for each pay strategy (see Table 4). Using the assumption that service costs increased linearly from 2003 to 2007, we then computed, for each of the three pay strategies, (a) the average service cost increase (2007 service cost minus 2003 service cost, divided by four), (b) 2004 service cost (2003 service cost plus the average service cost increase), (c) the average 2004-2007 service cost (2004 service cost plus 2007 service cost, divided by two), and (d) the total 2004-2007 service cost (average 2004-2007 service cost times four, the number of years in our simulation, times 5143, the total number of employees in each year).

Table 4
Estimated Four-Year Service Costs Under Different Pay Strategies

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Service Cost Multiplier (per employee)	**1.37**	**1.37**	**1.37**
Average Service Cost			
2003	$65,737	$65,737	$65,737
2007	$76,902	$77,972	$76,673
Yearly Increase in Service Costs	$2,791	$3,059	$2,734
2004 Average Service Cost	$68,528	$68,796	$68,471
Average Service Cost (2004 - 2007)	$72,715	$73,384	$72,572
Total Service Costs (2004 - 2007)	$1,495,892,980	$1,509,655,648	$1,492,951,184

Notes: 1. Average service cost per employee is assumed to equal 1.37 times Table 3's average salary under each pay strategy. Total costs were calculated assuming a linear growth in service costs. Thus, it was estimated to equal the number of employees times the number of years times the average service costs (2004-2007).
2. Data provided by the user **are in bold**.

An implication of our decision to use the workforce average service costs to estimate total service costs is that it implicitly assumes that replacement employees will be paid at the average level of the workforce they enter. The framework of this model can certainly accommodate other assumptions (e.g., stronger pay-performance links will attract better performers who will be paid more), and would allow practitioners to incorporate such data when appropriate. We adopted the workforce-average assumption for simplicity.

Pay strategy 2 yielded the highest service costs; it is projected to cost $13.76 million more than pay strategy 1 (no performance-pay relationship). Under pay strategy 2, pay is always equal (for performers at or below the performance midpoint) or higher (for performers above the midpoint) than pay in strategy 1. Pay strategy 3 raises the pay for higher performers, but also lowers pay for lower performers, resulting in costs of $2.94 million less over four years than pay strategy 1, and $16.70 million less than pay strategy 2.

Service costs (i.e., pay and benefits) are highly visible to standard accounting systems. In fact, one could argue that they are the most visible elements of human capital in standard accounting. Thus, if standard accounting were used to evaluate these pay policies, the costs shown in Table 4 would likely be quite evident, and would perhaps suggest an argument for pay strategy 3 to organizational constituents who rely on accounting information for their decisions. Given that the movement costs analysis suggested pay strategy 3 as the least economical approach, however, it is clear that relying on only a single type of cost information may well provide an inaccurate basis for a decision. When we do aggregate the total movement and total service cost data from Tables 3 and 4, we see that pay strategy 3 is the most expensive, costing over $23 million more than pay strategy 2 and over $24 million more than pay strategy 1.

Consequently, from a cost-based perspective, we might conclude that undertaking an aggressive pay-for-performance system to "win the talent war" is not worth the investment. We instead caution that such an inference (and any decisions based on it) is at the least premature and is potentially detrimental to the organization. High performers provide greater value than do low performers, and any assessment of an HR program that differentially affects the performance distribution of the workforce must account for this. HR investments must be examined for both their "efficiency" and "effectiveness" (Boudreau & Ramstad, 2003b). Hence, having addressed the movement and service costs implications of the three pay strategies' effects on turnover, we next turn to the strategies' implications for workforce's value, an often overlooked but absolutely essential consideration when assessing the financial practicality of human resource interventions.

Estimating the Value of Pay-For-Performance Plans

Step 6: Determine Service Value

Although our analyses have focused on the cost implications of the pay-for-performance strategies, such strategies also can produce value through the elimination of poor performers (and their subsequent replacement by average performers), and, in particular, the retention of high performers, whose retention is especially sensitive to pay-for-performance effects (Trevor et al., 1997). Moreover, when differences in individual performance are high (i.e., when a high performer is worth much more to the organization than an average performer), retaining top employees and eliminating poor employees may yield value that far outweighs the associated costs (Boudreau & Berger, 1985; Boudreau, 1991; Boudreau & Ramstad, 1999; 2003a; 2003b).

To examine the potential effects of performance-based pay on workforce value, we need to estimate the dollar value of individual performance variation. This will allow us to estimate the effect that changes in the workforce's performance distribution will have on workforce value. Our data provide estimates of changes in the performance ratings, so we must convert ratings to dollar values. This conversion method requires two components (Boudreau & Berger, 1985): (a) the dollar value of the average performance level; and (b) the incremental value of deviations from that average performance level.[3]

We employed the Schmidt and Hunter (1983) approach, which assumes that the value of the average performance level would equal 1.754 times the average wage at that level. For the 2003 work force, we multiplied Table 3's average salary of $47,983 by 1.754 to obtain a service value of $84,162 per person. For the 2007 work force, consistent with the estimate of average service costs above, we estimated average salary as that which would have been produced by four years of average salary increases, beginning in 2004. As noted in Table 3, the average 2007 salary under pay strategy 1, which allocates average salary increases across the performance distribution, is estimated to be $56,133. Multiplying this salary by 1.754 produces an average work force value estimate of $98,457 per person. These 2003 and 2007 average service value estimates are shown in "average service value" section of Table 5.

Table 5
Computations for Estimating Individual Service Value at Each Performance Level

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5
Number of employees	60	97	1171	1090	1667	672	317	46	23
Mean Performance		2.764							
Standard Dev. of Performance		0.668							
Z-Score of Performance Ratings	-2.641	-1.892	-1.144	-0.395	0.353	1.102	1.850	2.599	3.347
Average Service Value (assumed to equal 1.754 * average salary)									
2003	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162	$84,162
2007	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457	$98,457
Incremental Service Value **SDy =0.30**									
2003	-$38,017	-$27,235	-$16,468	-$5,686	$5,081	$15,863	$26,631	$37,412	$48,180
2007	-$44,474	-$31,861	-$19,265	-$6,652	$5,944	$18,558	$31,154	$43,767	$56,363
Incremental Service Value **SDy =0.60**									
2003	-$76,034	-$54,470	-$32,936	-$11,372	$10,163	$31,726	$53,261	$74,825	$96,359
2007	-$88,948	-$63,722	-$38,530	-$13,304	$11,889	$37,115	$62,308	$87,534	$112,726
Incremental Service Value **SDy =0.90**									
2003	-$114,051	-$81,705	-$49,403	-$17,058	$15,244	$47,590	$79,892	$112,237	$144,539
2007	-$133,423	-$95,583	-$57,795	-$19,955	$17,833	$55,673	$93,461	$131,301	$169,089
Total Individual Service Value (SDy = 30%)[1]									
2003	$46,145	$56,927	$67,694	$78,476	$89,243	$100,025	$110,793	$121,574	$132,342
2007	$53,983	$66,596	$79,192	$91,805	$104,401	$117,015	$129,611	$142,224	$154,820
Total Individual Service Value (SDy = 60%)									
2003	$8,128	$29,692	$51,226	$72,790	$94,325	$115,888	$137,423	$158,987	$180,521
2007	$9,509	$34,735	$59,927	$85,153	$110,346	$135,572	$160,765	$185,991	$211,183
Total Individual Service Value (SDy = 90%)									
2003	-$29,889	$2,457	$34,759	$67,104	$99,406	$131,752	$164,054	$196,399	$228,701
2007	-$34,966	$2,874	$40,662	$78,502	$116,290	$154,130	$191,918	$229,758	$267,546

Notes: 1. Total Individual Service Value is computed as the Average Service Value plus the Incremental Service Value, shown in the top portion of this table.
2. Data provided by the user **are in bold**.

For the second component necessary to estimate the value associated with each employee, we needed an estimate for the value of each performance level above and below the average. Combined with the estimate for the average value of individuals' performance, this will allow us to calculate the value of each of the nine performance levels, in both 2003 and 2007. In this study, and probably characteristic of most organizations, we had no direct estimates of the dollar value of particular performance levels. Hence, we used an estimation approach typical of utility analysis studies (e.g., Boudreau, 1991; Boudreau & Ramstad, 2003b). Utility analysis typically employs an estimate of the value of a one-standard-deviation difference in employee value, referred to as SDy, with SDy often approximated as equal to a given percentage of salary (Boudreau, 1991; Cascio, 2000). Thus, someone who performs one standard deviation above average (i.e., someone who is in the 84th percentile of performance) is estimated to be worth more than an average performer by a value equal to SDy. Using the SDy term, we can compute the value of each performance category relative to the average.

A recurring problem with using SDy is that it is unlikely to be estimated precisely (Boudreau, 1991; Cascio, 2000). Furthermore, its impact on final estimates of the value of a utility estimate is often quite significant (Boudreau, 1991). Thus, we investigated three potential values. As a very conservative approach, we assumed that SDy would equal 30% of average salary. This is substantially less than Schmidt and Hunter's (1983) 40% recommendation, which has been characterized as a conventional benchmark (Becker & Huselid, 1992), a safe estimate (Schmidt, Hunter, Outerbridge, & Trattner, 1986), and a conservative estimate (Judiesch, Schmidt, & Mount, 1992). We also used 60% of average salary as a somewhat conservative estimate, and we used 90% of average salary as what we believe to be a more realistic estimate.[4] In other words, our three estimates suggest that an employee performing better than 84 percent of the employee population is worth 30% of salary, 60% of salary, or 90% of salary more to the organization than an average performer (i.e., someone performing at the 50th percentile) in the same job.

In order to move from these SDy estimates to estimates of each employee's service value, we first used the observed distribution of employee performance to compute the standardized z-score corresponding to each of the nine performance ratings. This transformation, accomplished through subtracting the mean performance score from each performance category rating and then dividing by the performance standard deviation, produces a performance distribution with a mean of zero and a standard deviation of one. For example, performance category 1.5 received a z-score of -1.89 through subtracting the average performance rating of 2.764 from 1.5 and dividing by the standard deviation of 0.668. The z-scores, which represent the number of standard deviations that each performance category rating deviates from the performance mean, are listed in the fifth row of data in Table 5.

We assumed that the z-scores associated with each raw performance score would remain constant from 2003 to 2007. That is, although the actual distribution of workers across performance categories changes from 2003 to 2007, we assumed that the value of performance at each performance level did not change. For example, a performance rating of 4 in 2003, which was 1.850 standard deviations above the mean in 2003, provided value to the employer equal to mean performance's value plus the product of 1.850 and SDy. We assumed, regardless of the actual number of employees who received a score of 4 in 2007, the financial value of an individual with a performance rating of 4 in that year would be equal to 2007 mean performance's value plus the product of 1.850 and SDy.

For 2003, we estimated average salary as $47,983 (from Table 1), producing SDy estimates of $14,395 (i.e., 0.3 * $47,983), $28,790 (i.e., 0.6 * $47,983) and $43,185 (i.e., 0.9 * $47,983) for the 30%, 60% and 90% SDy scenarios, respectively. For 2007, estimated average salary was $56,133 (from Table 1), producing, at the 30%, 60%, and 90% SDy scenarios, estimated SDy levels of $16,840 (i.e., 0.3 * $56,133), $33,680 (i.e., 0.6 * $56,133), and $50,520 (i.e., 0.9 * $56,133). Multiplying these SDy estimates (i.e., the appropriate dollar value of a one standard deviation performance difference) by the z-scores (i.e., the number of standard deviations the performance category is from the mean) produced the "incremental" (beyond the average) dollar values corresponding to each performance rating level for each SDy assumption (see Table 5). Thus, under the 60% assumption in 2007, an employee at performance level 5.0 is worth $112,726 more than an average employee (i.e., $56,133 * 0.60 * 3.347). The sums of the average service values for the workforce, and the incremental service values for each performance category, produced the individual service values for each performance category that are reported in the bottom section of Table 5. Thus, the last six lines of data in Table 5 represent, for each unique combination of performance level (1.0 – 5.0 at half point intervals), year (2003 and 2007), and SDy scenario (30%, 60%, and 90%), the individual service value for each employee.

With individual service values determined for both 2003 and 2007, we can now compute the total service value for the workforce under each of the three pay strategies. For 2003 (for all three pay strategies), we calculated the total service value of the workforce by multiplying each performance category's individual service value by the corresponding quantity of employees in the performance category, and adding the products. Thus, for example, Table 5's individual service value of $115,888 for SDy = 60% and performance = 3.5 in 2003 is multiplied by 672 (the number of employees in that performance category) to yield the $77,876,736 figure in Table 6 (under SDy = 60% and performance = 3.5). This $77,876,736 is then added to the similarly computed values for the other eight performance categories to produce, when SDy = 60%, Table 6's total 2003 service value of $432,351,857. This is our estimate of what the workforce is worth to the employer in 2003 under the assumption that being one standard deviation above average in performance is worth 60% of an average performer's salary. We note that the total service values are the same in 2003 regardless of pay strategy (although they do differ across SDy assumptions) because the three pay strategies had yet to result in the different performance-specific turnover patterns that begin in 2004.

Table 6

Computing Total Service Value (2003 Employees)

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Number of employees	60	97	1171	1090	1667	672	317	46	23	5143
2003 Total Service Value										
SDy = 30%	$2,768,700	$5,521,919	$79,269,674	$85,538,840	$148,768,081	$67,216,800	$35,121,381	$5,592,404	$3,043,866	$430,072,965
SDy = 60%	$487,680	$2,880,124	$59,985,646	$79,341,100	$157,239,775	$77,876,736	$43,563,091	$7,313,402	$4,151,983	$432,351,857
SDy = 90%	-$1,793,340	$238,329	$40,702,789	$73,143,360	$165,709,802	$88,537,344	$52,005,118	$9,034,354	$5,260,123	$434,631,219

Note: The total service values are the same in 2003 regardless of pay strategy (although they do differ across SDy assumptions) because the three pay strategies had yet to result in the different performance-specific turnover patterns that begin in 2004.

For 2007, calculation of the total service value of the workforce is slightly more complex, as the computations for those employees retained over the four-year analysis differ from the computations required for those hired as replacements during the four-year period. For the retained employees, 2007 total service value calculation closely resembles the approach to 2003, where Table 5's 2003 individual service values for each SDy level and performance category combination were multiplied by the quantity of retained employees for each performance category, and these products were summed. In 2007, however, the three pay strategies' different effects on performance-specific turnover result in pay strategy-specific numbers of retained employees in each performance category. Consequently, we need to conduct the individual service value by employee quantity multiplications separately for each pay strategy to get the 2007 estimates. Thus, Table 5's 2007 individual service values for each SDy level and performance category combination were multiplied by the quantity of retained employees for each performance category under each pay strategy, and these products were summed. For example, Table 5's individual service value of $129,611 for SDy = 30% and performance = 4.0 in 2007 is multiplied by 231, 282, and 282 (the number of retained employees in that performance category under the three pay strategies, as listed in Table 7) to yield the $29,940,141, $36,550,302, and $36,550,302 figures in Table 7 (under SDy = 30%, performance = 4.0, and pay strategies 1, 2, and 3, respectively). Thus, the final nine rows of data in Table 7 chronicle, for each SDy and pay strategy combination, the combined service value of all retained employees in 2007 at each performance level. The final column for each of these nine rows provides total service values across performance categories.

Table 7

Total Service Value of Retained Employees (2007)

Performance Ratings:	1	1.5	2	2.5	3	3.5	4	4.5	5	Total
Retained Employees										
Pay Strategy 1	2	34	726	818	1317	524	231	27	8	3687
Pay Strategy 2	2	34	726	818	1317	578	282	41	20	3818
Pay Strategy 3	1	12	468	709	1317	578	282	41	20	3428
Total Service Value (2007)										
SDy = 30%										
Pay Strategy 1	$107,966	$2,264,264	$57,493,392	$75,096,490	$137,496,117	$61,315,860	$29,940,141	$3,840,048	$1,238,560	$368,792,838
Pay Strategy 2	$107,966	$2,264,264	$57,493,392	$75,096,490	$137,496,117	$67,634,670	$36,550,302	$5,831,184	$3,096,400	$385,570,785
Pay Strategy 3	$53,983	$799,152	$37,061,856	$65,089,745	$137,496,117	$67,634,670	$36,550,302	$5,831,184	$3,096,400	$353,613,409
SDy = 60%										
Pay Strategy 1	$19,018	$1,180,990	$43,507,002	$69,655,154	$145,325,682	$71,039,728	$37,136,715	$5,021,757	$1,689,464	$374,575,510
Pay Strategy 2	$19,018	$1,180,990	$43,507,002	$69,655,154	$145,325,682	$78,360,616	$45,335,730	$7,625,631	$4,223,660	$395,233,483
Pay Strategy 3	$9,509	$416,820	$28,045,836	$60,373,477	$145,325,682	$78,360,616	$45,335,730	$7,625,631	$4,223,660	$369,716,961
SDy = 90%										
Pay Strategy 1	-$69,932	$97,716	$29,520,612	$64,214,636	$153,153,930	$80,764,120	$44,333,058	$6,203,466	$2,140,368	$380,357,974
Pay Strategy 2	-$69,932	$97,716	$29,520,612	$64,214,636	$153,153,930	$89,087,140	$54,120,876	$9,420,078	$5,350,920	$404,895,976
Pay Strategy 3	-$34,966	$34,488	$19,029,816	$55,657,918	$153,153,930	$89,087,140	$54,120,876	$9,420,078	$5,350,920	$385,820,200

Having computed 2007 service value for retained employees, we next address the 2007 value of those employees hired to replace the employees that separated during the 2004-2007 window. These replacement employees were assumed to have an individual service value equal to the average individual service value of retained employees under pay strategy 1 for each of the SDy assumptions. Thus, for example, Table 8's average individual replacement employee service value of $101,594 when SDy = 60% was computed by dividing Table 7's total retainee service value of $374,575,510, which is under pay strategy 1 with SDy = 60%, by 3687, which is Table 7's total retainees under pay strategy 1. We note that using pay strategy 1's retainee service value for all replacements assumes that the recruiting effectiveness and job performance of replacement employees are not affected by the compensation system. Because the average service value of retained employees under pay strategies 2 and 3 is greater than the average service value of employees retained under pay strategy 1, this provides a conservative estimate of replacement service value under the two pay strategies with pay-for-performance links. The total service value of replacement employees for each pay strategy and SDy combination is equal to the pay strategy-specific number of replacements times the SDy-specific average service value. These totals are reported in the bottom three rows of data in Table 8.

Table 8
Service Value of Replacement Employees (2007)

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
Average Service Value			
SDy = 30%	$100,025	$100,025	$100,025
SDy = 60%	$101,594	$101,594	$101,594
SDy = 90%	$103,162	$103,162	$103,162
Number of Separations (2004-2007)	1457	1326	1716
Total Service Value of Replacements (2007)			
SDy = 30%	$145,736,425	$132,633,150	$171,642,900
SDy = 60%	$148,022,458	$134,713,644	$174,335,304
SDy = 90%	$150,307,034	$136,792,812	$177,025,992

Note: We are using the conservative assumption that replacement employees will have the service value of employees under the first pay strategy. Our approach implicitly assumes that the pay strategy has no effect on recruitment or job performance of new employees. If we assumed that new employees had service values equal to the average service values of employees under the new pay strategies, then the total service value of replacements would be higher under pay strategies 2 and 3.

Finally, Table 8's service values of the replacements and Table 7's service values of retained employees were added to produce the estimated 2007 total service value for each pay strategy and SDy level combination, as shown in Table 9. We used these 2007 total service values, as well as the 2003 total service values from Table 6, to compute total service value across all years in Table 10. As we had done with total service costs computations, we calculated the four-year stream of service value levels by assuming that service value rose linearly in each performance category between 2003 and 2007. Thus, for each pay strategy and SDy combination, we computed (a) the average service value increase (2007 service value minus 2003 service value, divided by four); (b) 2004 service value (2003 service value plus the average service value increase); (c) the average 2004-2007 service value (2004 service value plus 2007 service value, divided by 2); and (d), the total 2003-2007 service value (average 2003-2007 service value, times four, the number of years in our simulation).

Table 9
Total Service Value of the 2007 Workforce

	Value of Retained Employees	+	Value of Replaced Employees	=	Total Value (2007)
SDy = 30%					
Pay Strategy 1	$368,792,838	+	$145,736,425	=	$514,529,263
Pay Strategy 2	$385,570,785	+	$132,633,150	=	$518,203,935
Pay Strategy 3	$353,613,409	+	$171,642,900	=	$525,256,309
SDy = 60%					
Pay Strategy 1	$374,575,510	+	$148,022,458	=	$522,597,968
Pay Strategy 2	$395,233,483	+	$134,713,644	=	$529,947,127
Pay Strategy 3	$369,716,961	+	$174,335,304	=	$544,052,265
SDy = 90%					
Pay Strategy 1	$380,357,974	+	$150,307,034	=	$530,665,008
Pay Strategy 2	$404,895,976	+	$136,792,812	=	$541,688,788
Pay Strategy 3	$385,820,200	+	$177,025,992	=	$562,846,192

Table 10
Computing Four Year Total Service Value

	Pay Strategy 1	Pay Strategy 2	Pay Strategy 3
SDy = 30%			
2003 Service Value	$430,072,965	$430,072,965	$430,072,965
2007 Service Value	$514,529,263	$518,203,935	$525,256,309
Average Service Value Increase	$21,114,075	$22,032,743	$23,795,836
2004 Service Value	$451,187,040	$452,105,708	$453,868,801
Avg. (2004 - 2007 Service Value)	$482,858,152	$485,154,822	$489,562,555
Total Service Value (2004-2007)	$1,931,432,608	$1,940,619,288	$1,958,250,220
SDy = 60%			
2003 Service Value	$432,351,857	$432,351,857	$432,351,857
2007 Service Value	$522,597,968	$529,947,127	$544,052,265
Average Service Value Increase	$22,561,528	$24,398,818	$27,925,102
2004 Service Value	$454,913,385	$456,750,675	$460,276,959
Avg. (2004 - 2007 Service Value)	$488,755,677	$493,348,901	$502,164,612
Total Service Value (2004-2007)	$1,955,022,708	$1,973,395,604	$2,008,658,448
SDy = 90%			
2003 Service Value	$434,631,219	$434,631,219	$434,631,219
2007 Service Value	$530,665,008	$541,688,788	$562,846,192
Average Service Value Increase	$24,008,447	$26,764,392	$32,053,743
2004 Service Value	$458,639,666	$461,395,611	$466,684,962
Avg. (2004 - 2007 Service Value)	$494,652,337	$501,542,200	$514,765,577
Total Service Value (2004-2007)	$1,978,609,348	$2,006,168,800	$2,059,062,308

Under all assumptions about SDy, the 2007 and total service values are lowest when giving all employees average pay increases (pay strategy 1), are higher when giving high performers high pay increases and all others average increases (pay strategy 2), and are highest when the pay-for-performance link was strongest (pay strategy 3). Compared to pay strategy 1, which gives all employees average pay increases, pay strategy 2 prompts more high-performing and highly-paid employees to stay, and their value enhances the work force. Pay strategy 3 augments this effect by encouraging the turnover of low performers, who subsequently are replaced with workers whose expected value is that of average workers under pay strategy 1.

Hence, whereas our cost analysis suggested that pay strategy 3 was the least effective and pay strategy 1 was the most effective, our analysis of workforce value indicates the exact opposite. Obviously, relying only on either cost or value estimates would be shortsighted. The critical question is whether the service value benefits of a strong pay-for-performance link outweigh the costs (Boudreau, 1991; Boudreau & Ramstad, 2003a; 2003b).

Step 7: Determining the Final Utility—Is Pay-for-Performance Worth it?

At this point, we return to the flow chart in Figure 1 and the question that motivated this research effort: Is it worth it to use pay-for-performance in an attempt to win the war for talent? To speak to this, we began by specifying three pay plan strategies and estimating the subsequent turnover probabilities and performance distributions we would expect under each. Using this turnover and performance information, we then addressed costs for each pay plan through the estimation of expenses associated with employee movement out of and into the workforce and with the pay and benefits for the workforce. Having estimated costs, we turned to the benefits dimension of the cost-benefit analysis and estimated the value of the retained workforce and of the replacement employees. Thus, we have estimated the three components for the decision of whether pay-for-performance makes sense in our example: (a) the four-year stream of movement costs; (b) the four-year stream of service costs; and (c), the four-year stream of service value. Now, we combine these components to estimate the relative value of the three pay strategies by taking the stream of service value and subtracting the stream of service costs and movement costs (Boudreau & Berger, 1985). The relevant amounts are summarized in Table 11 for each pay strategy and SDy assumption combination.

Table 11
Computation of Four Year Investment Value of Different Pay Strategies (in $millions)

	Service Value (in $millions)	-	Service Costs (in $millions)	-	Movement Costs (in $millions)	=	Four Year Value (in $millions)	Difference from Pay Strategy 1	% Change from Pay Strategy 1
SDy = 30%									
Pay Strategy 1	$1,931.43		$1,495.89		$154.67		$280.87	--	--
Pay Strategy 2	$1,940.62		$1,509.66		$142.05		$288.91	$8.04	2.86%
Pay Strategy 3	$1,958.25		$1,492.95		$181.80		$283.50	$2.62	0.91%
SDy = 60%									
Pay Strategy 1	$1,955.02		$1,495.89		$154.67		$304.46	--	--
Pay Strategy 2	$1,973.40		$1,509.66		$142.05		$321.69	$17.22	5.66%
Pay Strategy 3	$2,008.66		$1,492.95		$181.80		$333.91	$29.44	9.15%
SDy = 90%									
Pay Strategy 1	$1,978.61		$1,495.89		$154.67		$328.05	--	--
Pay Strategy 2	$2,006.17		$1,509.66		$142.05		$354.46	$26.41	8.05%
Pay Strategy 3	$2,059.06		$1,492.95		$181.80		$384.31	$56.26	15.87%

These results suggest a different conclusion from the cost analysis presented earlier. Recall that traditional compensation-cost analyses may have led decision makers to the conclusion that a strong link between pay and performance would be unwise given its extreme cost, and that although a moderate pay-for-performance link was not much more expensive than having no link, there were no cost-based data to strongly suggest it as a compelling alternative. When the potential benefits of workforce value are accounted for, however, it becomes clear that investments in performance-based pay may hold the potential for significant organizational improvement. Table 11 indicates that even under our most conservative SDy assumption, pay-for-performance plans yielded greater net values than did the non-contingent pay strategy. That is, by fully incorporating both costs and benefits into our assessment, we find that, under all of our conditions, pay-for-performance is indeed a valuable investment. Moreover, as SDy (i.e., the value associated with performance differences) became larger, the payoff to pay-for-performance increased dramatically, ultimately (i.e., at SDy = 90%) resulting in advantages, relative to the non-contingent pay from pay strategy 1, of over $26 and $56 million dollars for the partially contingent and highly contingent pay strategies, respectively.

Discussion

This analysis suggests that even under conservative assumptions about the value of performance variability among employees, the four-year financial benefit of linking pay to performance in this company would be substantial. When these SDy assumptions are closer to what we believe to be more realistic (i.e., if job performance differences have greater value to an organization), the present model reveals the potentially high payoff from investments in performance-based pay. Moreover, our analysis vividly illustrates the limitations of standard accounting and behavioral cost-based approaches for identifying the critical variables and, thus, the appropriate pay strategy.

Simplifying decisions

Because utility analysis can be rather complex, we used a number of simplifying decisions here. First, we assumed that replacement employees would be of average performance level (and, thus, average service value). This implicitly assumes that pay-for-performance would not influence applicant attraction, even though research suggests that the degree to which pay and performance are linked does in fact matter to applicants (Cable & Judge, 1994). Second, in focusing on the relationship between pay-for-performance and turnover, we made no provisions for whether the performance-based pay would actually improve workforce performance (net of retention effects). This implicit modeling of no effect of performance-based pay on performance is particularly noteworthy given that the contingent pay plan in the Trevor et al. (1997) study was sufficiently well designed to elicit a performance-specific retention pattern. Third, we were working with the relatively normally distributed performance distribution from the Trevor et al. sample. While using this distribution simplified matters by allowing us to make use of other aspects of the Trevor et al. study, we recognize that many performance distributions may be characterized by a greater proportion of employees being rated in the top two or three performance categories and by the subsequent negative skew. The Trevor et al. distribution arose because the organization, consistent with its individualistic and hierarchical culture, encouraged differentiation among employees during performance appraisal. Additionally, because Trevor et al. used averaged performance levels (with a mean of 3.05 performance ratings per employee), such factors as change in performance over time and random error in ratings combined to reduce the likelihood of having an average rating in the very top or bottom performance levels. To the extent that an organization with an aggressive pay-for-performance plan does encourage or mandate a normal performance distribution, however, the implications are noteworthy. For example, the system allocates large raises to the relatively few high performers, who should then be satisfied, motivated, and likely to remain; in contrast, the system also may frustrate, de-motivate, and ultimately result in increased turnover among employees that might be reasonably high performers but were not rated as such as a result of the forced distribution.

We emphasize that each of the three simplifying decisions was made to facilitate our presentation rather than strengthen our results. Indeed, each decision actually weakens the results' apparent support for performance-based pay. In unreported analyses, we incorporated into the utility analysis improved applicant quality under pay strategies 2 and 3, improved performance (net of retention effects) under pay strategies 2 and 3, and a more negative skew in the performance distribution. In each case, these alternative approaches to the decision in question resulted in a larger net advantage for pay strategy 2 and, to an even greater extent, for pay strategy 3. Thus, the analyses we presented here are a simplified and conservative approach. The spreadsheets available from the first author can be adapted to test such alternative assumptions.

On Overcoming the "Futility of Utility"

Our simplifying decisions notwithstanding, the analyses presented here entail much detail and speculation that, according to utility analysis criticism, might hinder their acceptance in managerial ranks. Indeed, we are quite aware of the "futility of utility" (Latham & Whyte, 1997; Whyte & Latham, 1994) findings in which utility analysis appeared to reduce managerial support for an HR intervention. To a large extent, the futility of utility problem likely resides within the presenter and recipients of utility analysis data, rather than with utility analysis itself.

In defense of utility analysis, Sturman (2000) concludes that managers need to understand utility analysis and be trained in the use of the technology. Citing the necessity of managers making decisions based on the Merton and Scholes options pricing formula to have experience in finance and economics, Sturman (2000) argued that “For a complex decision making tool to be useful, the users of the decision aid must desire the information it provides and be trained in its use” (p. 297). Hence, rather than being apologists for the complexity of utility analysis, we believe that in-house I/O psychologists should attempt to convey that it is important for key stakeholders to have some basic grounding in sophisticated human resource decision-making. Given that labor costs often comprise over half of all operating costs (Milkovich & Newman, 2002), training decision makers in a decision tool designed to inform as to the optimal way to allocate these costs would appear to be a valid undertaking. On the presenter side, Cronshaw (1997), after participating as the expert utility presenter in the Whyte and Latham (1997) “futility” study, contended that “it is not utility analysis per se that imperils I/O psychologists, but the intemperate way it is often used. In effect, the messenger kills the message” (p. 614). Cronshaw advocated that utility analysis should be presented as an informational tool rather than as a “persuasive tool in a one-sided (and often self-serving) attempt to ‘sell’ innovations to managers” (p. 614).

Boudreau and Ramstad (1999; 2002) noted that the powerful influence of disciplines such as Finance and Marketing evolved from their focus on enhancing decisions about the key resource (money or customers), rather than on selling accounting or sales programs, and suggested that the influence of HR and I/O professionals will increase with a similar focus on talent decisions. They suggested (Boudreau & Ramstad, 2002, 2003a; 2003b) the HC BRidge® decision model for “talent” resources that draws upon well-developed decision models to delineate three fundamental elements: efficiency, effectiveness and impact. The present analysis vividly shows the value of integrating “efficiency” (payroll and movement costs); “effectiveness” (changes in movement patterns); and “impact” (value of improvements in performance) into a decision support model, and the dangers of decision frameworks based solely on efficiency or effectiveness alone.

In addition to these emphases on decision maker training and on presenting utility analysis as an informative tool rather than marketing it as a panacea, we also offer a few additional suggestions that might assist the I-O psychologist in communicating utility analyses. First, expectations should be set at the outset by affirming that the evaluation will be somewhat complex, just as would be expected from manufacturing, finance, or accounting. Any simplistic attempt to estimate performance-based pay's effects on the bottom line would be superficial and incomplete. Second, communicating the utility analysis would probably benefit from an initially broad explanation. Perhaps using something similar to our Figure 1 as a guide, the practitioner should emphasize the simple cost-benefit concepts of movement costs, service costs, performance-specific retention, and the critical, but often overlooked, workforce value. We believe that it would be wise to continually hearken back to these big picture concepts, with emphasis on effects rather than on measures (Cascio, 2000) and technical details (Hoffman, 1996). Third, acceptance may be facilitated via emphasis on the conservative nature of the assumptions, decisions, and subsequent estimates (Hoffman, 1996). Finally, highlighting the rationale for these assumptions and decisions should demystify them, and using the spreadsheets to instantaneously show the effects of changing them may provide valuable "best case" and "worse case" scenarios. Together, these recommendations should assist in indicating that well-designed performance-based pay is worth considering, and that HR is able to quantitatively evaluate the relevant alternatives.

Limitations and Conclusions

Several limitations are noteworthy. Our results reflect one organization's characteristics, such as plan specifics, the individual job performance distribution, and the relationship between pay-for-performance and turnover. The extent to which this organization, its employees, and our conclusions are representative of other firms and employees with regard to these factors is unknown. What is critical, however, is that the approach we took to finding these results can be applied in a wide variety of situations, thus enabling the examination of external validity. A second limiting factor in our study is that there may be additional pay strategy-specific training costs or administrative costs that we did not include. We believe, however, that such costs could easily be incorporated into this framework. Third, as discussed throughout this study, we made a number of assumptions and decisions in order to conduct the analyses. Although we believe that we took the most logical and conservative approaches at these junctures, viable arguments could be made for approaches different from our own. Fourth, although we modeled employees' performance levels as stable over time, research has shown that employee performance levels change over time (e.g., Deadrick, Bennett, & Russell, 1997; Ployhart & Hakel, 1998; Sturman & Trevor, 2001). Furthermore, changes in performance levels are related to the likelihood of turnover, even after controlling for the effects of current performance levels (Harrison et al., 1996; Sturman & Trevor, 2001). Considering the movement of employees between different performance categories across years, and the implications of these movements for forecasting turnover, would certainly add complexity to the model we presented. It may be valuable for future research to explore the implications of these model refinements.

The method we describe involves a significant amount of calculation, but is relatively simple to replicate on a spreadsheet. Actual replication may require some customization to fit a specific company's profile, but the basic premise of the methods should be the same. We hope that this demonstration will inspire organizations to more fully tap available research findings to help them enhance their HR policy decision-making. We also hope that this paper helps demonstrate the value of research findings like those reported in Trevor et al. (1997) and will be complemented by future research on additional factors that may influence the pay-for-performance link with turnover. For example, satisfaction with different types of pay-for-performance plans (e.g., raises versus bonuses) can have different effects on outcomes of organizational interest, such as job satisfaction and organizational commitment (Sturman & Short, 2000). Ideally, the research presented here will encourage extensions of this work that can prove valuable for both understanding HR practices in general and for evaluating specific HR policies.

Organizations of all types will likely respond to increasing pressures to “win the talent war” by employing all available tools to enhance attraction, selection, and retention processes. A formidable tool in this endeavor is the accumulated knowledge available from industrial/organizational psychology and human resources research. The method described here illustrates how utility analysis can be used to demystify and integrate this research, making it a more practical decision-making tool, and thus a more potent influence on significant strategic organizational goals (Boudreau, 1991; Boudreau & Ramstad, 1997; 1999; 2002; 2003a; 2003b).

References

Bartlett, C. A., & Ghoshal, S. (2002). Building competitive advantage through people. MIT Sloan Management Review, 43 (2), 34-41.

Becker, B. E., & Huselid, M. A. (1992). Direct estimates of SDy and the implications for utility analysis. Journal of Applied Psychology, 77, 227-233.

Berman, J. M. (2001). Industry output and employment projections to 2010. Monthly Labor Review, 124 (11), 39-56.

Boudreau, J. W. (1991). Utility analysis for decisions in human resource management. In M. D. Dunnette & L. M. Hough (Eds.), Handbook of industrial and organizational psychology (2nd Edition., Vol. 2, pp. 621-745). Palo Alto, CA: Consulting Psychologists Press, Inc.

Boudreau, J. W., & Berger, C. J. (1985). Decision-theoretic utility analysis applied to employee separations and acquisitions [Monograph]. Journal of Applied Psychology, 70, 581-612.

Boudreau, J.W. & Ramstad, P.M. (2002). From “professional business partner” to “strategic talent leader”: “What’s next” for human resource management. Working Paper 02-10, Center for Advanced Human Resource Studies, Cornell University. Ithaca, New York.

Boudreau, J.W. & Ramstad, P.M. (2003a). Strategic HRM measurement in the 21st century: From justifying HR to strategic talent leadership. In M. Goldsmith, R.P. Gandossy and M.S. Efron (eds.) HRM in the 21st Century, 79-90. New York: John Wiley

Boudreau, J.W. & Ramstad, P.M. (2003b). Strategic I/O psychology and the role of utility analysis models. In W. Borman, D. Ilgen and R. Klimoski (eds.). Handbook of Psychology, (Vol. 12, “Industrial and Organizational Psychology”, Chapter 9, 193-221). New York: John Wiley.

Boudreau, J.W. & Ramstad, P.R. (1999). Human resource metrics: Can measures be strategic? In P. Wright, L. Dyer, J. Boudreau & G. Milkovich (eds.) Strategic human resources management in the twenty-first century. Supplement 4 to G.R. Ferris (ed.) Research in personnel and human resource management, 75-98. Stamford, CT: JAI Press.

Boudreau, J.W. & Ramstad, P.R. (1997). “Measuring Intellectual Capital: Learning from Financial History.” Human Resource Management, 36 (3), pp. 343-356.

Branch, S. (1998). You hired ‘em, but can you keep ‘em? Fortune, 138, November 9, 247-250.

Bureau of Labor Statistics (2002). National Compensation Survey: Occupational Wages in the United States, 2001. [On-line data source]. Washington, DC: US Department of Labor, Bureau of Labor Statistics.

Cable, D. M., & Judge, T. A. (1994). Pay preference and job search decisions: A person-organization fit perspective. Personnel Psychology, 47, 317-348.

Cascio, W. F. 2000. Costing human resources: The financial impact of behavior in organizations (4th edition). Boston, MA: Kent.

Chambers, E. G., Handfield-Jones, H., Hanking, S.M., & Michaels, E.G., III (1998). Win the war for top talent. Workforce, December, 50-56.

Cronshaw, S. F. (1997). Lo! The stimulus peaks: The insiders view on Whyte and Latham’s “The Futility of Utility Analysis.” Personnel Psychology, 50, 611-616.

Deadrick, D. L., Bennett, N., & Russell, C. J. (1997). Using hierarchical linear modeling to examine dynamic performance criteria over time. Journal of Management, 23, 745-757.

Dreher, G. F. (1982). The role of performance in the turnover process. Academy of Management Journal, 25, 137-147.

Fullerton, H. N. Jr., & Toosi, M. (2001). Labor force projections to 2010: Steady growth and changing composition. Monthly Labor Review, 124 (11), 21-38.

Gerhart, B. (2000). Compensation strategy and organizational performance. In S.L.Rynes & B. Gerhart (eds.), Compensation in organizations. San Francisco: Jossey-Bass.

Gerhart, B., & Milkovich, G. T. (1992). Employee compensation: Research and practice. In M. D. Dunnette & L. M.Hough (Eds.), Handbook of industrial and organizational psychology (2nd Edition, Vol. 3, pp. 481-569). Palo Alto, CA: Consulting Psychologists Press, Inc.
Griffeth, R. W., Hom, P. W., & Gaertner, S. (2000. A meta-analysis of antecedents and correlated of employee turnover: Update, moderator tests, and research implications for the next millennium. Journal of Management, 26, 463-488.
Harrison, D. A., Virick, M., & William, S. (1996). Working without a net: Time, performance, and turnover under maximally contingent rewards. Journal of Applied Psychology, 81, 331-345.
Hewitt Associates. (2002). Twenty-sixth annual U.S. salary increase survey. Lincolnshire, IL.
Hoffman, C. C. (1996). Applying utility analysis to guide decisions on selection system content. Journal of Human Resource Costing and Accounting, 1, 9-17.
Hollenbeck, J. R., & Williams, C. R. (1986). Turnover functionality versus turnover frequency: A note on work attitudes and organizational effectiveness. Journal of Applied Psychology, 71, 606-611.
IOMA. (2002, May). Pay for performance report. New York: Institute of Management and Administration.
Jackofsky, E. F. (1984). Turnover and job performance: An integrated process model. Academy of Management Review, 9, 74-83.
Jenkins, D.G. Jr., Mitra, A., Gupta, N., & Shaw, J.D. (1998). Are financial incentives related to performance? A meta-analytic review of empirical research. Journal of Applied Psychology, 83, 777-787.
Johnson, A. A. (1995). The business case for work-family programs. Journal of Accountancy, 180 (2), 53-57.
Judiesch, M. K., Schmidt, F. L., & Mount, M. K. (1992). Estimates of the dollar value of employee output in utility analyses: An empirical test of two theories. Journal of Applied Psychology, 77, 234-250.
Kalbfleisch, J. D., & Prentice, R. L. (1980). The statistical analysis of failure time data. New York: John Wiley and Sons, Inc.
Klass, B. S., & McClendon, J. A. (1996). To lead, lag, or match: Estimating the financial impact of pay level policies. Personnel Psychology, 49, 121-141.
Kohn, A. (1993, September-October). Why incentive plans cannot work. Harvard Business Review, 54-63.
Latham, G. P., & Whyte, G. (1994). The futility of utility analysis. Personnel Psychology, 47, 31-46.
McKinsey & Company (1998). The war for talent. New York: McKinsey & Company.
Milkovich, G. T., and Newman, J. M. (2002). Compensation (7th ed). Irwin: Boston, MA.
Morita, J. G., Lee, T. W., & Mowday, R. T. (1993). The regression-analog to survival analysis: A selected application to turnover research. Academy of Management Journal, 36, 1430-1464.
Peck, C. (2002). Salary increase budgets: 2002 increases fall in many industries, rebound projected for 2003. Executive Action, 24 (June), 1-5.
Pfeffer, J. (1998). Six dangerous myths about pay. Harvard Business Review, May/June, 76, 108-120.
Ployhart, R. E., & Hakel, M. D. (1998). The substantive nature of performance variability: Predicting interindividual differences in intraindividual performance. Personnel Psychology, 51, 859-901.
Porter, L. W., & Lawler, E. E. (1968). Attitudes and performance. Homewood, Ill.: Irwin-Dorsey.
Raju, N. S., Burke, M. J., & Normand, J. (1990). A new approach for utility analysis. Journal of Applied Psychology, 75, 3-12.

Retherford, R.D., & Choe, M.K. (1993). Statistical models for causal analysis. New York: John Wiley & Sons.
Rich, J. T. (1999). The growth imperative. The Journal of Business Strategy, March/April, 20, 27-31.
Schmidt, F. L., & Hunter, J. E. (1983). Individual differences in productivity: An empirical test of estimates derived from studies of selection procedure utility. Journal of Applied Psychology, 68, 407-414.
Schmidt, F. L., Hunter, J. E., Outerbridge, A. N., & Trattner, M. H. (1986). The economic impact of job selection methods on size, productivity, and payroll costs of the federal work force: An empirically based demonstration. Personnel Psychology, 39, 1-29.
Schwab, D. P. (1991). Contextual variables in employee performance-turnover relationships. Academy of Management Journal, 34, 966-975.
Sherwyn, D. S., & Sturman, M. C. (2002). Job-sharing in the hotel industry: A potential new human resource tool resulting from the events of September 11th. Cornell Hotel and Restaurant Administration, 43 (5), 84-91.
Solomon, J. (1988). Companies try measuring cost savings from new types of corporate benefits. The Wall Street Journal (Dec. 29), B1.
Steers, R. M. & Mowday, R. T. (1981). Employee turnover and the post decision accommodation process. In B. M. Staw & L. L. Cummings (Eds.), Research in Organizational Behavior (pp. 235-281). Greenwich, CT: JAI Press.
Sturman, M. C. (2000). Implications of utility analysis adjustments for estimates of human resource intervention value. Journal of Management, 26, 281-299.
Sturman, M. C., & Short, J. C. (2000). Lump-sum bonus satisfaction: Testing the construct validity of a new pay satisfaction dimension. Personnel Psychology, 53, 673-700
Sturman, M. C., & Trevor C. O. (2001). The implications of linking the dynamic performance and employee turnover literatures. Journal of Applied Psychology, 86, 684-696.
Trevor, C.O. (2001). Interactive effects among actual ease of movement determinants and job satisfaction in the prediction of voluntary turnover. Academy of Management Journal, 44, 621-638.
Trevor C. O., Gerhart, B., & Boudreau, J. W. (1997). Voluntary turnover and job performance: Curvilinearity and the moderating influences of salary growth and promotions. Journal of Applied Psychology, 82, 44-61.
U.S. Department of Labor. (2001). Employer Costs for Employee Compensation: March 2001, Washington, D.C.: U.S. Department of Labor.
Whyte, G., & Latham, G. P. (1997). The futility of utility analysis revisited: When even an expert fails. Personnel Psychology, 50, 601-610.
Williams, C. R., & Livingstone, L. P. (1994). Another look at the relationship between performance and voluntary turnover. Academy of Management Journal, 37, 269-298.
WorldatWork (2002). 29th Annual Report on the 2002-2003 Total Salary Increase Budget Survey. Scottsdale, AZ: WorldatWork.

Footnotes

1. The Boudreau and Berger (1985) model in its purest form would calculate the work force value in each intervening year and apply a discount factor to equalize the time value of the dollar amounts. While these economic corrections can yield substantial changes to the estimated value (Sturman, 2000), such embellishments do not have a significant effect in this case because the changes in dollar amounts are assumed to be linear, the time frame is relatively short, and our focus is on the relative (versus absolute) value of the different strategies. We also did not have information about the organizational tax rate, so we report our results in pre-tax dollars. After-tax effects could be easily calculated by multiplying the final results by an appropriate after-tax proportion, but the relative effects of the options would not be altered.

2. The Bureau of Labor Statistics provides a wealth of information on hourly earnings for diverse groups and occupations (see BLS, 2002). We used the average hourly earnings and weekly hours of all white collar occupations, excluding sales jobs. The most recent information shows that white collar, full-time employees (excluding sales) earned an average hourly wage of $21.65 and worked an average of 39.4 hours per week in 2001. Based on the 29th Annual Report on the 2002-2003 Total Salary Increase Budget Survey (WorldatWork, 2002), salary increases averaged 3.9% for exempt salaried employees in 2002, and is projected to increase 4.1% for 2003. This led us to use an estimated hourly wage of $23.42, for a total salary for 2003 of $47,983. Note again that anyone employing the methods described in this paper can simply enter the data from other sources, such as their own company's data. The value we chose was intended to capture a broad, generalizable sample. More importantly, it is intended to be a reasonable estimate to help illustrate our technique.

3. There is no single accepted method of estimating the dollar value of average performance among workers or applicants. Some research has suggested that average performance value can be estimated equal to the average compensation of the work group (Boudreau, 1991, p. 654; Raju, Burke & Normand, 1990, p. 9). However, it seems unlikely that average-performing employees produce only enough value to offset their direct wage costs. Considering the other service costs that are incurred, and the need for organizations to obtain a positive return on costs, a higher level of average service value seems likely. Based on an analysis of wage and productivity estimates in the national income accounts of the United States, Schmidt and Hunter (1983) proposed assuming that the ratio of average dollar value to average wage is approximately 1.754.

4. Support of the 90% approach is provided by Becker and Huselid (1992), who found direct observations of SDy fell in the 74% to 100% of mean salary range. Moreover, because researchers generally contend that SDy increases as job complexity increases (e.g., Judiesch et al., 1992), our 30% and 60% SDy values would appear to have additional support as conservative estimates, given our sample of all exempt hires in a large company.

Appendix

Computing Separation Probabilities Using Survival Analysis Results

Our estimation uses the survival analysis from Trevor et al.'s (1997) Table 4 (model 1).

Probability of survival = $S(0)^{e^{(ßX)}}$,
where S(0) = baseline probability of survival, which was 0.77,
ß = a vector of survival analysis regression coefficients,
X = a vector of independent variables,
(ßX) = 4.941 + 0.314 * Salary Growth - 2.541 * Performance + 0.553 * Performance^2 - 0.020 * Performance^3 + 0.007 * Salary Growth^3 - 0.663 * Salary Growth * Performance + 0.071 * Salary Growth * Performance^2

The salary growth data used to estimate the equation above was measured in thousands of dollars. Thus, to use the equation, our example's percentage increases had to be converted to a parallel salary growth measure for each pay strategy and performance level combination. To do so, we determined the average pay growth under each strategy by subtracting 2003 pay from 2007 pay, dividing by 4, and then dividing this amount by 1000.

For example, under strategy 3 and performance level 2.5, the average pay increase was [($54,005 - $47,983) / 4]/1000 = 1.5055. The table below lists the salary growth for each pay strategy and performance level.

Performance Category	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0
Strategy 1	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375	2.0375
Strategy 2	2.0375	2.0375	2.0375	2.0375	2.0375	2.5853	3.1485	3.7283	4.3243
Strategy 3	0.000	0.4870	0.9888	1.5055	2.0375	2.5853	3.1485	3.7283	4.3243

Next, we need to estimate separation probability (i.e., 1 - probability of survival): $1 - S(0)^{e^{(ßX)}}$. For example, for performers rated at 5.0 under Pay Strategy 2, the pay increase of 8% translates to an average dollar increase (in thousands) of 4.3243, which yields a separation probability = $1 - .77^{e^{(ßX)}} = 1 - .77^{e^{(4.941 - 5.467)}} = 1 - .77^{e^{(-0.526)}} = 1 - .77^{(0.5910)}$ = 1 - 0.86 = 0.14. See Table 2 for separation probabilities at each performance level/pay strategy combination.

The 4.941 constant in the (ßX) calculation resulted from adding the estimated model constant (6.810) from Trevor et al.'s equation to the sum of the model terms that included neither performance nor salary growth (e.g. age, promotions). These terms were evaluated at the means of the respective X variables. As an aside, we advocate centering variables prior to conducting hazard analyses, which causes the model constant and variables set at their means to drop out, thus simplifying the calculation of survival probabilities (Retherford & Choe, 1993; Trevor, 2001). See Trevor (2001) and Morita et al. (1993) for more on computing survival probabilities.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	**)**	
A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	
Environmental Compliance Plan; (3) An Order	**)**	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

DAVID A. DAVIS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, David A.Davis, being duly sworn, deposes and says he is the Manager, Property Accounting Policy and Research that he has personal knowledge of the matters set forth in the forgoing testimony for which he is identified as the witness contained therein is true and correct to the best of his information, knowledge and belief.

David A. Davis

David A. Davis

STATE OF OHIO)
) Case No. 2014-00396
County of FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by David A. Davis, this the 10th day of December, 2014.

Kathy L Messer

Notary Public

My Commission Expires: August 18, 2017

DIRECT TESTIMONY OF
DAVID A. DAVIS ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

EXHIBITS

DIRECT TESTIMONY OF
DAVID A. DAVIS ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David A. Davis. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am an employee of American Electric Power Service Corporation ("AEPSC") a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). My position is Manager – Property Accounting Policy and Research.

My responsibilities include providing the AEP electric operating subsidiaries with accounting support for regulatory filings, including the preparation of depreciation studies and testimony. I also monitor regulatory proceedings and legislation for accounting implications and assist in determining the appropriate regulatory accounting treatment.

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

A. I received a Masters Degree in Business Administration from the University of Dayton in 1988. I also have a Bachelors degree in Business Administration with a major in accounting from Ohio University that I received in 1976. I am a Certified Public Accountant (Inactive) in the state of Ohio. In 1980, I was employed by Columbus

Southern Power Company ("CSP"), one of the AEP operating companies, as an accountant. I have held various positions in the Accounting Department including Special Studies, Reports and Lease Accounting. From 1984 to 1985, I was employed by Columbia Gas System Service Corporation as a staff auditor, where my responsibilities included financial and procedural audits of the Columbia Gas Distribution Companies and other subsidiary companies. From 1986 to present, I have been employed by AEP at the Service Corporation, CSP or Ohio Power. At AEP, I have held several positions including Supervisor of Consolidation Accounting, Manager/Supervisor of Property Accounting (for 16 years) and my current position of Property Accounting Policy and Research Manager.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. See Exhibit DAD-1 which details my rate case experience.

Q. HAVE YOU HAD ANY FORMAL TRAINING RELATING TO DEPRECIATION AND UTILITY ACCOUNTING?

A. Yes. I am a former President of the Society of Depreciation Professionals (SDP) and have completed training offered by the SDP that included Depreciation Basics, Life Analysis for Valuations, Life and Net Salvage Analysis, and Preparing and Defending a Depreciation Study. These training classes included an introduction to Plant and Depreciation Accounting, Data Requirements and Collection, Depreciation Models, Life Cycle Analysis, Current Regulatory Issues, Actuarial Life Analysis, Net Salvage Analysis and Simulation Life Analysis. I am a member of the American Institute of

Certified Public Accountants and have attended and participated in numerous Edison Electric Institute Property Accounting and Valuation meetings.

In addition, I traveled to Tirana, Albania in 2010 with the USAID program to provide a presentation to Albanian utility personnel regarding "Depreciation for a Regulated Utility".

II. PURPOSE OF TESTIMONY

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

A. My testimony recommends revised depreciation accrual rates for Kentucky Power Company's ("Kentucky Power" or "Company") electric plant in service based on a depreciation study for electric utility plant in service at December 31, 2013. Schedules I and II in the Depreciation Study Report detail the results of the study. The depreciation rates determined by the study are intended to provide recovery of invested capital, cost of removal, and credit for salvage over the expected life of the property.

The revised depreciation rates are primarily required due to changes in investment and changes in the expected life and net salvage of Kentucky Power's property that takes into account the December 2013 transfer of a 50% undivided interest in the Mitchell generating station from AEP affiliate Ohio Power Company to Kentucky Power as approved by the Kentucky Public Service Commission ("Commission") in Case No. 2012-00578. In the Stipulation and Settlement Agreement attached to that case, the Commission ordered that Kentucky Power would use current Ohio Power Company depreciation rates for Mitchell Units 1 and 2 until such rates are changed in the Base Rate Case. Consistent with the Stipulation and Settlement Agreement, the

Company is proposing a change in the Mitchell Plant's depreciation rates. The depreciation rate changes are based on my depreciation study which uses 2040 as the plant's estimated retirement year.

The Company is not recommending any revision to Big Sandy Plant's depreciation rates in this filing since Unit 2 is planned for retirement at the end of May 2015 and the coal related portions of Unit 1 are planned for retirement in April 2016.

The order from the Mitchell transfer Case No. 2012-00578 allows Kentucky Power to recover the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site related retirement costs that will no longer be used. The costs are further detailed in the testimony of Company Witness Yoder. New depreciation rates will be required for Big Sandy Unit 1 after it is repowered to use natural gas in 2016.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring EXHIBIT DAD-1 which details my rate case experience, EXHIBIT DAD-2 which includes my depreciation study report and EXHIBIT DAD-3 which is a copy of the Sargent & Lundy dismantling study performed for Mitchell Plant to provide terminal removal costs for the Mitchell units.

Q. WERE THESE EXHIBITS PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

III. DEFINITION OF DEPRECIATION

Q. PLEASE EXPLAIN THE DEFINITION OF DEPRECIATION AS USED IN PREPARING YOUR DEPRECIATION STUDY.

A. The definition of depreciation that I used in preparing the study is the same that is used by the FERC and the National Association of Regulatory Utility Commissioners. That definition is:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.
>
> Service value means the difference between original cost and the net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant.

IV. DEPRECIATION STUDY OVERVIEW

Q. HOW DO THE DEPRECIATION RATES AND ANNUAL ACCRUALS CALCULATED IN YOUR 2013 DEPRECIATION STUDY COMPARE WITH KENTUCKY POWER'S CURRENT RATES AND ACCRUALS?

A. A comparison of Kentucky Power's current rates and accruals and the study rates and accruals is shown below based on total Company depreciable plant balances at December 31, 2013:

Table 1 - Depreciation Rates and Accruals
Based on Depreciable Plant In Service at December 31, 2013

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Steam Production (1)	3.80%	54,851,796	3.36%	48,418,617	(6,433,179)
Transmission	1.71%	8,478,288	2.66%	13,169,805	4,691,517
Distribution	3.52%	24,312,736	4.48%	30,971,933	6,659,197
General	2.54%	858,462	4.42%	1,492,241	633,779
Total Depreciable Plant	3.32%	88,501,282	3.50%	94,052,596	5,551,314

Note: (1) Includes Big Sandy and Mitchell plants. The Company is not recommending a change in depreciation rates for Big Sandy Plant due to the planned retirement of Unit 2 in 2015 and the coal related portions of Unit 1 in 2016.

Based on results of the depreciation study which includes a 50% share of the Mitchell Generating Station I recommend an increase in annual depreciation expense due to a change in depreciation rates of $5,551,314 using depreciable plant balances at December 31, 2013. The changes in depreciation rates are necessary because of changes in average service lives and the net salvage estimates used to calculate the Company's depreciation rates.

Kentucky Power's current depreciation rates (excluding Mitchell Plant) are based on a 1991 settlement agreement in Case No. 91-066 which were made effective on April 1, 1991. The Mitchell Plant's depreciation rates were set in Case No. 2012-00578 where the Commission ordered Kentucky Power to use Ohio Power Company depreciation rates for Mitchell Units 1 and 2 until such rates changed in a future Base Rate Case.

V. STUDY METHODS AND PROCEDURES

Q. PLEASE BRIEFLY DESCRIBE THE METHODS AND PROCEDURES USED IN THE STUDY.

A. The methods and procedures are fully described in my depreciation study report labeled Exhibit DAD-2. In summary, all of the property included in the depreciation report was considered on a group plan. Under the group plan, depreciation is accrued upon the basis of the original cost of all property included in each depreciable plant group instead of individual items of property. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accumulated provision for depreciation regardless of the age of the particular item retired. Also under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. In this study, the plant groups consisted of the individual primary plant accounts for Production, Transmission, Distribution and General Plant property. The depreciation rates were calculated by using the Average Remaining Life Method, which is the same method that was used to calculate Kentucky Power's current depreciation rates. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation over the average remaining life of the plant.

Mitchell Plant original cost, accumulated depreciation and terminal net salvage was included at Kentucky's 50% share at December 31, 2013. The Big Sandy amounts listed on Schedules I and II in the Depreciation Study Report are also at December 31, 2013 but due to the planned retirement of Big Sandy Unit 2 in 2015 and the coal related portions of Big Sandy Unit 1 in 2016, new depreciation rates are not recommended for Big Sandy Plant in this depreciation study.

A separate depreciation rate was calculated for Mitchell Plant's SCR catalyst since AEP Generation determined that the catalyst has a shorter life than other plant assets (8 years).

The average service lives for the Company's Transmission, Distribution and General Plant were determined using statistical procedures similar to those used in the insurance industry in studies of human mortality. The historical retirement experience of property groups was studied and retirement characteristics of the property were described using the Iowa-type retirement dispersion curves.

Net salvage for each property group was determined based on actual historical experience for Production, Transmission, Distribution and General Plant accounts. In addition the depreciation rate calculation for Mitchell Plant includes a terminal net salvage amount. To determine this amount, Kentucky Power commissioned the independent engineering firm, Sargent & Lundy ("S&L"), to prepare a conceptual dismantling cost estimate to be included in Kentucky Power's depreciation rates for Mitchell Plant.

Q. WHY DID KENTUCKY POWER RETAIN S&L TO PERFORM A DISMANTLING STUDY OF THE MITCHELL PLANT'S GENERATING UNITS?

A. The S&L dismantling study provides estimated removal cost and salvage amounts specific to Mitchell Plant and is therefore a reasonable method to arrive at future expected terminal net salvage amounts. A copy of the S&L dismantling study is included with my testimony as EXHIBIT DAD-3.

Q. WERE THERE ANY ADJUSTMENTS MADE TO THE RESULTS OF THE MITCHELL PLANT'S DISMANTLING STUDY WHEN ADDING THE S&L NET SALVAGE AMOUNTS TO THE DEPRECIATION STUDY?

A. Yes. S&L provided terminal net salvage amounts, excluding any asbestos, ash pond or landfill type removal costs, in 2012 dollars. I applied a 2.35% escalation rate factor to the net salvage amounts provided by the S&L study to determine the terminal net salvage amount at 2040 the estimated retirement date for the Mitchell Plant. The terminal net salvage amount after escalation was used in the calculation of net salvage percentages in the depreciation study.

Q. WHAT IS THE SOURCE OF THE 2.35% ESCALATION RATE USED FOR THIS PURPOSE?

A. The 2.35% escalation rate was taken from a publication titled "The Livingston Survey" dated December 12, 2013. The Livingston Survey is published by the research department of the Federal Reserve Bank of Philadelphia and provides a long term outlook projecting an escalation rate for a 10 year period.

Q. WHY DID S&L'S MITCHELL PLANT DISMANTLING STUDY ESTIMATE EXCLUDE THE COST TO REMOVE ASBESTOS AND TO COVER ASH PONDS AND LANDFILLS?

A. The cost to remove asbestos and to cover ash ponds and landfills are included in the Company's accounting for asset retirement obligations (ARO) and the depreciation and accretion on these ARO's are incorporated in the cost of service outside of the depreciation study.

Q. WOULD YOU PLEASE EXPLAIN WHY YOU CALCULATED A SEPARATE DEPRECIATION RATE FOR MITCHELL PLANT'S SELECTIVE CATALYTIC REDUCTION (SCR) CATALYST?

A. Yes. AEP Engineering determined that the depreciable life of the Mitchell Plant SCR catalyst was approximately 8 years. Since the life of the catalyst is much shorter than the remaining life of the plant, it is more appropriate to depreciate it over a shorter life than the remaining life of the plant.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE DEPRECIATION RATES CALCULATED BY THE DEPRECIATION STUDY?

A. Yes. Kentucky Power currently applies depreciation rates and maintains accumulated depreciation by functional plant classification (Production, Transmission, Distribution and General). I recommend that the Commission authorize Kentucky Power to adopt and apply the proposed depreciation accrual rates at the primary plant account level, and that the accumulated depreciation by primary plant account be established as of the date the revised depreciation rates become effective. Maintaining accumulated depreciation at the primary account level will facilitate monitoring depreciation accruals and actual salvage and removal activity for future depreciation study purposes.

VI. <u>STUDY RESULTS</u>

Q. WOULD YOU PLEASE EXPLAIN THE RESULTS OF YOUR STUDY FOR STEAM PRODUCTION PLANT?

A. Yes. The composite depreciation rate for Steam Production Plant decreased from 3.80% to 3.36% primarily due to the change in Mitchell Plant's estimated retirement year to 2040 from 2031. The current Mitchell Plant depreciation rates (those used by Ohio Power Company at the December 31, 2013 transfer date) are based on a 2031 retirement date.

Q. WOULD YOU PLEASE EXPLAIN THE RESULTS OF YOUR STUDY FOR TRANSMISSION PLANT?

A. Yes. The depreciation rate for Transmission Plant increased from 1.71% to 2.66% due to increases in the net salvage ratio for 5 accounts (accounts 352, 353, 354, 355, and 356) and decreases in the average service life for two accounts (354, and 355). These changes were partially offset by an increase in average service life for account 352.

Q. WOULD YOU PLEASE EXPLAIN THE RESULTS OF YOUR STUDY FOR DISTRIBUTION PLANT?

A. Yes. The depreciation rate for Distribution Plant increased from 3.52% to 4.48% due to increases in the net salvage ratio for nine accounts (accounts 361, 362, 364, 365, 367, 368, 369, 371 and 373) and a decrease in the average service life for one account (account 370). The increase was partially offset by an increase in average service life for five accounts (accounts 361, 362, 366, 369, and 373) and a decrease in the net salvage ratio for account 370.

Q. WOULD YOU PLEASE EXPLAIN THE RESULTS OF YOUR STUDY FOR GENERAL PLANT?

A. Yes. The depreciation rate for General Plant increased from 2.54% to 4.42% due to an increase in the net salvage ratio for three accounts (391, 394 and 398) and a reduction in the average service life for account 390. The increase was partially offset by a decrease in the net salvage ratio for account 397.

Q. DO YOU SPONSOR ANY ADJUSTMENTS IN THIS CASE?

A. Yes, I sponsor three adjustments in this case. Adjustment No. 37 annualizes depreciation expense at September 30, 2014 for Transmission, Distribution and General property using the depreciation rates recommended by the depreciation study and calculates an adjustment that reflects the difference between the actual twelve month ended September 30, 2014 book depreciation and the annualized amount. Adjustment No. 39 annualizes depreciation expense at September 30, 2014 for Mitchell Plant using depreciation rates recommended by the depreciation study and calculates an adjustment that reflects the difference between the actual twelve month ended September 30, 2014 book depreciation and the annualized September amount. Adjustment No. 40 annualizes depreciation expense at September 30, 2014 for Big Sandy Plant's remaining plant in service after the retirement of Big Sandy Unit 2 and the coal related portions of Unit 1 using current depreciation rates (which are the rates recommended by the depreciation study) and calculates an adjustment that reflects the difference between the actual twelve month ended September 30, 2014 book depreciation and the annualized amount. The support for these adjustments is provided in Section V, Exhibit 2.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

RATE CASE EXPERIENCE OF DAVID A. DAVIS					
No.	**Year**	**Company**	**Commission**	**Case, Cause or Docket No.**	**Items Provided/Filed**
1.	2006	Public Service of Oklahoma	Oklahoma Corporation Commission	Cause No. PUD 200600285	Oral and written Testimony and Depreciation Study
2.	2007	Southwestern Electric Power Company	Louisiana Public Service Commission	Docket No. U-23327, Subdocket A	Provided a Depreciation Study for Generation
3.	2008	Public Service of Oklahoma	Oklahoma Corporation Commission	Cause No. PUD 200800144	Oral and written Testimony and Depreciation Study
4.	2009	Southwestern Electric Power Company	Arkansas Public Service Commission	Docket No. 09-008-U	Filed written Testimony and Depreciation Study
5.	2009	Southwestern Electric Power Company	Public Utility Commission of Texas	Docket No. 37364	Filed written Testimony and Depreciation Study
6.	2010	Public Service of Oklahoma	Oklahoma Corporation Commission	Cause No. PUD 201000050	Filed written Testimony and Depreciation Study
7.	2011	Columbus Southern Power Company and Ohio Power Company	Public Utility Commission of Ohio	Case Nos. 11-351-EL-AIR and 11-352-EL-AIR	Filed written Testimony and Depreciation Study
8.	2011	Southwestern Electric Power Company	Louisiana Public Service Commission	Docket No. U-23327, Subdocket F	Provided a Depreciation Study for Generation
9.	2011	Indiana Michigan Power Company	Michigan Public Service Commission	Case No. U-16801	Oral and written Testimony and Depreciation Study

RATE CASE EXPERIENCE OF DAVID A. DAVIS					
No.	**Year**	**Company**	**Commission**	**Case, Cause or Docket No.**	**Items Provided/Filed**
10.	2011	Indiana Michigan Power Co.	Indiana Utility Regulatory Commission	Cause No. 44075	Testified and filed Testimony and Depreciation Study
11	2012	Southwestern Electric Power Company	Public Utility Commission of Texas	Docket No. 40443	Oral and written Testimony and Depreciation Study
12	2012	Transource Missouri, LLC	Federal Energy Regulatory Commission	Docket No. ER12-2554-000	Testimony and Depreciation Study
13	2012	Appalachian Power Company	Federal Energy Regulatory Commission	Docket No. ER13-0539-000	Testimony and Exhibits – to show how book depreciation is calculated in formula rates
14	2013	Appalachian Power Company	Virginia State Corporation Commission	Case No. PUE-2012-00141	Oral and written rebuttal Testimony in asset transfer case for Mitchell Plant and OPCo's share of Amos U3
15	2013	Indiana Michigan Power Company	Michigan Public Service Commission	Case No. U-17524	Filed a Depreciation Study for Steam Generation Plant
16	2014	Appalachian Power Company	Virginia State Corporation Commission	Case No. PUE-2014-00026	Filed written Testimony and Depreciation Study
17	2014	Appalachian Power Company	Public Service Commission of West Virginia	Case No. 14-0546-E-PC	Filed rebuttal Testimony in asset transfer case for

RATE CASE EXPERIENCE OF DAVID A. DAVIS					
No.	**Year**	**Company**	**Commission**	**Case, Cause or Docket No.**	**Items Provided/Filed**
					Mitchell Plant
18	2014	Transource Wisconsin, LLC	Federal Energy Regulatory Commission	Docket No. ER15-13-000	Testimony and Depreciation Study
19	2014	Indiana Michigan Power Company	Indiana Utility Regulatory Commission	Cause No. 44555	Filed a Depreciation Study for Steam Generation Plant

KENTUCKY POWER COMPANY

DEPRECIATION STUDY REPORT

OF

ELECTRIC PLANT IN SERVICE

AT

DECEMBER 31, 2013

DEPRECIATION STUDY REPORT

Table of Contents

I. INTRODUCTION

This report presents the results of a depreciation study of Kentucky Power Company's (KPCo) depreciable electric utility plant in service at December 31, 2013. The study was prepared by David A. Davis, Manager – Property Accounting Policy and Research at American Electric Power Service Corporation (AEPSC). The purpose of the depreciation study was to develop appropriate annual depreciation accrual rates for each of the primary plant accounts that comprise the functional groups for which KPCo computes its annual depreciation expense.

The recommended depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in Section II of this report.

The definition of depreciation used in my Study is the same as that used by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."
>
> "Service value means the difference between original cost and the

net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant." (FERC Accounting and Reporting Requirements for Public Utilities and Licensees, ¶15.001.)

Schedule I of this report shows the recommended depreciation accrual rates by primary plant accounts and composited to functional plant classifications. Schedule II compares depreciation expense using rates approved by the Commission and rates recommended by the depreciation study. Schedule III shows a comparison of the current mortality characteristics that were used to compute the recommended depreciation rates and the mortality characteristics used to determine the existing depreciation rates and accruals for Transmission, Distribution and General Plant Functions. A comparison of KPCo's current functional group composite depreciation rates and accruals to recommended functional group rates and accruals based on December 31, 2013 depreciable plant balances follows:

Table 1 - Depreciation Rates and Accruals
Based on Depreciable Plant In Service at December 31, 2013

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Steam Production (1)	3.80%	54,851,796	3.36%	48,418,617	(6,433,179)
Transmission	1.71%	8,478,288	2.66%	13,169,805	4,691,517
Distribution	3.52%	24,312,736	4.48%	30,971,933	6,659,197
General	2.54%	858,462	4.42%	1,492,241	633,779
Total Depreciable Plant	3.32%	88,501,282	3.50%	94,052,596	5,551,314

Note: (1) Includes Big Sandy and Mitchell plants. The Company is not recommending a change in depreciation rates for Big Sandy Plant due to the planned retirement of Unit 2 in 2015 and the coal related portions of Unit 1 in 2016.

Based on Total Company Depreciable Plant In-Service as of December 31, 2013, I am recommending an increase in depreciation rates that result in an increase in annual depreciation expense of $5,551,314. The depreciation rate changes are necessary because of changes in average service lives and net salvage estimates used to calculate KPCo's recommended depreciation rates that takes into account the December 31, 2013 transfer of a 50% undivided interest in the Mitchell generating station from AEP affiliate Ohio Power Company as approved by the Kentucky Public Service Commission (or Commission) in Case No. 2012-00578. KPCo's current approved depreciation rates with the exception of Mitchell Plant rates are based on a 1991 settlement agreement in Case No. 91-066 and were made effective on April 1, 1991. The Stipulation and Settlement Agreement in Case No. 2012-00578 ordered Kentucky Power to use the current Ohio Power Company depreciation rates for Mitchell Plant until such rates are changed in a base rate case.

II. DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

1. Group Method

All of the depreciable property included in this report was considered on a group plan. Under the group plan, depreciation expense is accrued upon the basis of the original cost of all property included in each depreciable plant account. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accrued depreciation reserve regardless of the age of the particular item retired. Also, under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The annual accruals by primary account were then summed, to arrive at the total accrual for each functional group. The total accrual divided by the original cost yields the functional group accrual rate.

2. Annual Depreciation Rates Using the Average Remaining Life Method

KPCo's current depreciation rates are based on the Average Remaining Life Method. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation, over the average remaining life of the plant. By this method, the annual depreciation rate for each account is determined on the following basis:

$$\text{Annual Depreciation Expense} = \frac{(\text{Orig. Cost})\ (\text{Net Salvage Ratio}) - \text{Accumulated Depreciation}}{\text{Average Remaining Life}}$$

$$\text{Annual Depreciation Rate} = \frac{\text{Annual Depreciation Expense}}{\text{Original Cost}}$$

3. Methods of Life Analysis

Depending upon the type of property and the nature of the data available from the property accounting records, one of three life analyses was used to arrive at the historically realized mortality characteristics and service lives of the depreciable plant investments. These methods are identified and described as follows:

Life Span Analysis

The life span analysis was employed for Mitchell Plant. The life-span method of analysis is particularly suited to specific location property, such as generating plants, where all of the surviving investments are likely to be retired in total at a future date. The key elements in the life span analysis are the age of the surviving investments, the projected retirement date of the facility and the expected interim retirements. Interim retirements are those retirements that are expected to occur between the date of the depreciation study and the expected final retirement date of the generating plant. Examples of interim retirements include fans, pumps, motors, a set of boiler tubes, a turbine rotor, etc. The interim retirement history for each primary production plant account was analyzed and the results of those analyses were used to project future interim retirements. The age of Mitchell Plant's surviving investments at December 31, 2013 was obtained from the accounting records of affiliate Ohio Power Company (OPCo). American Electric Power Service Corporation (AEPSC) provided the retirement date used in the life-span analysis for Mitchell Plant.

The Company is not recommending any revision to Big Sandy Plant's depreciation rates in this filing since Unit 2 is planned for retirement at the end of May 2015 and the coal related portions of Unit 1 are planned for retirement in April 2016. KPCo expects to repower Big Sandy Unit 1 to use natural gas in 2016.

The order in the Mitchell transfer Case No. 2012-00578 allows Kentucky Power to recover the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site related retirement costs that will not continue in use. New depreciation rates will be required for Big Sandy Unit 1 after it is repowered to use natural gas in 2016.

Steam Production Plant

At December 31st, 2013, KPCo's depreciable investment in Steam

Production Plant includes the Big Sandy Generating plant and a 50% undivided interest in Mitchell Generation Plant. The Big Sandy plant is located highway 23 near Louisa, Kentucky and includes two generating units. The Mitchell Plant is located on the Ohio River near Moundsville, West Virginia and also consists of two generating units. All generating units at the Big Sandy and Mitchell plants are currently coal fired.

The generating units and their capacities are as follows (also shown on Schedule IV – Estimated Generation Plant Retirement Dates):

Plant	Unit	Rating	Commercial Operating Date
Big Sandy	1	260 MW	1963
Big Sandy	2	800 MW	1969
Mitchell	1	770 MW	1971
Mitchell	2	790 MW	1971

AEPSC evaluated each of the generating units and determined the following retirement dates for the units:

Plant	Unit	Retirement Date
Big Sandy	2	2015
Big Sandy	1	2016 coal related portion
Big Sandy	1	2031 repowered to use natural gas
Mitchell Plant	1,2	2040

Since KPCo's last depreciation study (property investment dated December 31, 2008), AEP has reevaluated the expected retirement dates for its generation plant including Big Sandy Units 1-2. The reevaluation for these two Big Sandy units indicated that their current estimated retirement dates should be 2015 for Big Sandy Unit 2, 2016 for the coal related portion of Big Sandy Unit 1 and 2031 for Big Sandy Unit 1 after it is repowered to use natural gas. AEP previously estimated individual unit retirement dates of 2023 for Unit 1 and 2029 for Unit 2. According to AEP, the earlier Big Sandy Unit 2 and the coal related portion of Unit 1 retirement dates are because it is not economically feasible to equip the units with necessary environmental controls, not because they have reached the end of their service lives.

Current plans are for the Mitchell Plant to operate for a total life of 69 years or until 2040.

Actuarial Analysis – Transmission, Distribution and General Plant

This method of analyzing past experience represents the application to industrial property of statistical procedures developed in the life insurance field for investigating human mortality. It is distinguished from other methods of life estimation by the requirement that it is necessary to know the age of the property at the time of its retirement and the age of survivors, or plant remaining in service; that is, the installation date must be known for each particular retirement and for each particular survivor.

The application of this method involves the statistical procedure known as the "annual rate method" of analysis. This procedure relates the retirements during each age interval to the exposures at the beginning of that interval, the ratio of these being the annual retirement ratio. Subtracting each retirement ratio from unity yields a sequence of annual survival ratios from which a survivor curve can be determined. This is accomplished by the consecutive multiplication of the survivor ratios. The length of this curve depends primarily upon the age of the oldest property. Normally, if the period of years from the inception of the account to the time of the study is short in relation to the expected maximum life of the property, an incomplete or stub survivor curve results.

While there are a number of acceptable methods of smoothing and extending this stub survivor curve in order to compute the area under it from which the average life is determined, the well-known Iowa Type Curve Method was used in this study.

By this procedure, instead of mathematically smoothing and projecting the stub survivor curve to determine the average life of the group, it was assumed that the stub curve would have the same mortality characteristics as the type curve selected. The selection of the appropriate type curve and average life is accomplished by plotting the stub curve, superimposing on it Iowa curves of the various types and average lives drawn to the same scale, and then determining which Iowa type curve and average life best matches the stub.

The Actuarial Method of Life Analysis was used for the following accounts:

352.0 Transmission Structures & Improvements
353.0 Transmission Station Equipment
361.0 Distribution Structures & Improvements
362.0 Distribution Station Equipment
390.0 General Structures & Improvements

The result of the actuarial analysis for the above accounts is detailed in the depreciation study work papers.

Simulated Plant Record Analysis – Transmission and Distribution Plant

The "Simulated Plant Record" (SPR) method designates a class of statistical techniques that provide an estimate of the age distribution, mortality dispersion and average service life of property accounts whose recorded history provides no indication of the age of the property units when retired from service. For each such account, the available property records usually reveal only the annual gross additions, annual retirements and balances with no indication of the age of either plant retirements or annual plant balances. For this study, the "Balances method" of analysis was used.

The SPR Balances Method is a trial and error procedure that attempts to duplicate the annual balance of a plant account by distributing the actual annual gross additions over time according to an assumed mortality distribution. Specifically, the dollars remaining in service at any date are estimated by multiplying each year's additions by the successive proportion surviving at each age as given by the assumed survivor characteristics. For a given year, the balance indicated is the accumulation of survivors from all vintages and this is compared with the actual book balance. This process is repeated for a different survivor curves and average life combinations until a pattern is discovered which produces a series of "simulated balances" most nearly equaling the actual balances shown in a company's books.

This determination is based on the distribution producing the minimum sum of squared differences between the simulated balance and the actual balances over a test period of years.

The iterative nature of the simulated methods makes them ideally suited for computerized analysis. For each analysis of a given property account, the computer program provides a single page summary containing the results of each analysis indicating the “best fit” based on criteria selected by the user.

The results of my analysis using the Balance Method is shown in the depreciation study work papers. The analysis also shows the value of the Index of Variation of the difference that is calculated according to the the Balances Method where a lower value for the Index of Variation indicates better agreement with the actual data.

The SPR Method of Life Analysis was utilized for the following accounts:

354.0 Transmission Towers & Fixtures
355.0 Transmission Poles & Fixtures
356.0 Transmission Overhead Conductor & Devices
364.0 Distribution Poles, Towers & Fixtures
365.0 Distribution OH Conductor & Devices
366.0 Distribution Underground Conduit
367.0 Distribution Underground Conductor & Devices
368.0 Distribution Line Transformers
369.0 Distribution Services
370.0 Distribution Meters

371.0 Installation on Customers Premises

373.0 Street Lighting & Signal Systems

Vintage Year Accounting – General Equipment

In 1998, the Company began using a vintage year accounting method for general plant accounts 391 to 398 in accordance with Federal Energy Regulatory Commission Accounting Release Number 15 (AR-15). This accounting method requires the amortization of vintage groups of property over their useful lives. AR-15 also requires that property be retired when it meets its average service life.

As a result, my recommendation for these accounts is that the current useful life approved by the Commission be retained and used to continue amortization of the account balances.

4. Final Selection of Average Life and Curve Type

The final selection of average life and curve type for each depreciable plant account analyzed by the Actuarial and SPR Methods was primarily based on the results of the mortality analyses of past retirement history.

III. NET SALVAGE

1. Net Salvage - Steam Production Plant

The net salvage analysis for steam production plant included a review of the plant's experienced functional interim retirement, salvage and removal history for the period 2001-2013. No interim retirements were estimated for Big Sandy Plant in this depreciation study since Unit 2 is estimated to retire in 2015, the coal related portions of Unit 1 are estimated to retire in 2016 and the repowered Unit 1 (to use natural gas) is expected to retire in 2031.

While a standard type of analysis was used by the depreciation study to determine the net salvage characteristics applicable to interim retirements for the plants, the most significant net salvage amounts for generating plants occurs at the end of their life. Therefore, to assist in establishing total net salvage applicable to Big Sandy and Mitchell plants, the Company contracted with Sargent & Lundy (S&L) to prepare conceptual demolition cost estimates. The S&L cost estimates to demolish the plants are based on current (2013) price levels which were inflated to retirement dates in the depreciation study. These estimates were incorporated into the calculation of a net salvage ratio for Steam Production Plant. S&L's demolition costs do not include Asset Retirement Obligation (ARO) amounts associated with the removal of asbestos or any cost associated with the final disposition of Big Sandy or Mitchell Plant landfills and ash ponds. The costs to remove asbestos and cover ash ponds are included separately in the cost of service through the accounting for asset retirement obligations.

2. Net Salvage – Transmission, Distribution and General Plant

The net salvage percentages used in this report for Transmission, Distribution and General Plant are expressed as percent of original cost and are based on the Company's experience combined with the judgment of the analyst. KPCo maintains salvage and removal costs in its depreciation ledger at the functional plant level, rather than by primary plant accounts. To determine gross salvage, gross removal and net salvage percentages for individual plant accounts, original cost retirements, salvage and removal were taken from the Company's account history in its PowerPlant software which detailed these amounts by account for the period 2000 to 2013. Gross salvage and cost of removal percentages were calculated using the data from this fourteen year time period for each account. The salvage and removal percentages for each account were then netted to determine a net salvage percentage for each account.

The net salvage percents were converted to net salvage ratios (1 minus the net salvage percentage) and appear in Column IV on Schedule I and were used to determine the total amount to be recovered through depreciation. The same net salvage was also reflected in the determination of the calculated depreciation requirement, which was used to allocate accumulated depreciation at the functional group to the accounts comprising each group.

5. Net Salvage – Ratios

The net salvage ratios shown on Schedule I of this report may be explained as follows:

a. Where the ratio is shown as unity (1.00), it was assumed that the net salvage in that particular account would be zero.

b. Where the ratio is less than unity, it was assumed that the salvage exceeded the removal costs. For example, if the net salvage were 20%, the net salvage ratio would be expressed as .80.

c. Where the ratio is greater than unity, it was assumed that the salvage was less than the cost of removal. For example, if the net salvage were minus 5%, the net salvage ratio would be expressed as 1.05.

IV. CALCULATION OF DEPRECIATION REQUIREMENT AT DECEMBER 31, 2013

The accumulated depreciation by functional group was allocated to individual plant accounts based on the calculation of a depreciation requirement (theoretical reserve) for each plant account using the average service life, curve type and net salvage amount recommended in this study.

V. STUDY RESULTS

Production, Transmission, Distribution and General plant results are discussed below. In addition, Transmission, Distribution and General Plant average service life, retirement dispersion pattern and net salvage percentages used to calculate each primary plant account depreciation rate are shown on Schedule III where the mortality characteristics and net salvage values for the current rates are also shown. The changes to the mortality characteristics follow trends shown by historical retirement experience. Gross salvage and gross cost of removal percentages were largely based on the history of each account for the period 2000-2013.

Steam Production Plant

Depreciation rates for Mitchell Plant were calculated by plant account with the expectation that the total cost including net salvage would be recovered by 2040 which is the estimated retirement date for Mitchell Plant. New depreciation rates for Big Sandy Plant were not recommended by the depreciation study. The comparison of steam production depreciation accruals on Schedule II using the currently approved depreciation rates and the study depreciation rates includes

Mitchell Plant. The original cost and accumulated depreciation amounts used for Mitchell Plant are 50% of the plant's original cost and accumulated depreciation on KPCo's books at December 31, 2013.

The decrease in steam production depreciation expense due to a change in depreciation rates was primarily due to the longer life estimate for Mitchell Plant in this proceeding (2040 retirement date) versus a previously estimated 2031 retirement date. The depreciation study doesn't recommend any changes to the Big Sandy Plant's depreciation rates.

Terminal demolition costs are included in the steam production depreciation rates. The estimates of demolition costs were developed by Sargent & Lundy. S&L estimated demolition cost in 2013 dollars for Big Sandy Plant and Mitchell Plant (KPCo's 50% share) was $28,831,786 and $21,185,697, respectively.

Transmission Plant

The depreciation rates for Transmission plant increased from 1.71% to 2.66% due to increases in the net salvage ratio for five accounts (accounts 352, 353, 354, 355 and 356) and decreases in the average service life for two accounts (accounts 354, and 355). The increase was partially offset by an increase in the average service life for account 352.

Distribution Plant

The depreciation rates for Distribution plant increased from 3.52% to 4.48% due to increases in the net salvage ratio for nine accounts (accounts 361, 362, 364, 365, 367, 368, 369, 371 and 373) and a decrease in the average service life for one account (account 370). The increase was partially offset by a decrease in the net salvage ratio for account 370 and by increases in the average service life for five accounts (accounts 361, 362, 366, 369 and 373).

General Plant

The depreciation rates for General plant increased from 2.54% to 4.42% due to increases in the net salvage ratio for three accounts (accounts 391, 394 and 398) and a reduction in the average service life for account 390. The increase was partially offset by a decrease in the net salvage ratio for account 397.

SCHEDULE I – EXPLANATION OF COLUMN HEADINGS

Schedule I shows the determination of the recommended annual depreciation accrual rate by primary plant accounts by the straight line remaining life method. An explanation of the schedule follows:

Column I	-	Account number.
Column II	-	Account title.
Column III	-	Original Cost at December 31, 2013
Column IV	-	Net Salvage Ratio.
Column V	-	Total to be Recovered (Column III) * (Column IV).
Column VI	-	Calculated Depreciation Requirement.
Column VII	-	Allocated Accumulated Depreciation – accumulated depreciation (book reserve) spread to each account on the basis of the Calculated Depreciation Requirement shown in Column VI.
Column VIII	-	Remaining to be Recovered (Column V - Column VII).
Column IX	-	Average Remaining Life.
Column X	-	Recommended Annual Accrual Amount.
Column XI	-	Recommended Annual Accrual Percent or Depreciation Rate (Column X/Column III).

KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct. No.	Account Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Big Sandy Plant (1)										
311	Structures & Improvements	43,291,665	**(1)**	**(1)**	**(1)**	30,726,379	**(1)**	**(1)**	1,636,425	3.78%
312	Boiler Plant Equipment	362,456,070	**(1)**	**(1)**	**(1)**	177,325,748	**(1)**	**(1)**	13,700,839	3.78%
312	Boiler Plant Equip SCR Catalyst **(2)**	8,147,622	**(1)**	**(1)**	**(1)**	5,742,300	**(1)**	**(1)**	389,456	4.78%
314	Turbogenerator Units	109,522,949	**(1)**	**(1)**	**(1)**	61,149,688	**(1)**	**(1)**	4,139,967	3.78%
315	Accessory Electrical Equip.	16,513,202	**(1)**	**(1)**	**(1)**	12,896,303	**(1)**	**(1)**	624,199	3.78%
316	Misc. Power Plant Equip.	8,709,178	**(1)**	**(1)**	**(1)**	5,351,493	**(1)**	**(1)**	329,207	3.78%
	Total	548,640,686				293,191,911			20,820,093	3.79%
Mitchell Plant (3)										
311	Structures & Improvements	42,000,197	1.07	44,940,211	18,282,178	16,183,402	28,756,809	25.01	1,149,812	2.74%
312	Boiler Plant Equipment	765,644,984	1.07	819,240,133	245,324,500	238,518,432	580,721,701	24.25	23,947,287	3.13%
312	Boiler Plant Equip SCR Catalyst **(2)**	8,190,115	1.00	8,190,115	4,023,394	2,378,493	5,811,622	4.07	1,023,764	12.50%
314	Turbogenerator Units	53,295,697	1.07	57,026,396	29,106,660	33,613,523	23,412,873	23.84	982,084	1.84%
315	Accessory Electrical Equip.	17,080,672	1.07	18,276,319	9,466,086	11,043,285	7,233,034	25.81	280,242	1.64%
316	Misc. Power Plant Equip.	7,693,412	1.07	8,231,951	3,289,590	3,072,520	5,159,431	23.96	215,335	2.80%
	Total	893,905,077	1.07	955,905,125	309,492,408	304,809,655	651,095,470	23.59	27,598,524	3.09%
	Total Steam Prod. Plant	**1,442,545,763**	**0.66**	**955,905,125**	**309,492,408**	**598,001,566**	**651,095,470**	**13.45**	**48,418,617**	**3.36%**
TRANSMISSION PLANT										
350.1	Land Rights	26,456,147	1.00	26,456,147	8,498,622	7,016,166	19,439,981	50.91	381,850	1.44%
352	Structures & Improvements	6,636,668	1.10	7,300,335	3,172,075	2,618,754	4,681,581	33.93	137,978	2.08%
353	Station Equipment	170,843,671	1.03	175,968,981	34,476,675	28,462,741	147,506,240	40.20	3,669,309	2.15%
354	Towers & Fixtures	94,517,543	1.10	103,969,297	56,679,229	46,792,396	57,176,901	23.20	2,464,522	2.61%
355	Poles & Fixtures	74,696,720	1.61	120,261,719	28,658,583	23,659,527	96,602,192	32.75	2,949,685	3.95%
356	OH Conductor & Devices	122,537,908	1.27	155,623,143	70,585,347	58,272,803	97,350,340	27.32	3,563,336	2.91%
357	Undergrnd Conduit	11,590	1.00	11,590	4,345	3,587	8,003	23.13	346	2.99%
358	Undergrnd Conductor	106,066	1.00	106,066	49,568	40,922	65,144	23.44	2,779	2.62%
	Total Transmission Plant	495,806,313	**1.19**	589,697,279	202,124,444	166,866,896	422,830,383	32.11	13,169,805	2.66%
DISTRIBUTION PLANT										
360.1	Land Rights	5,343,520	1.00	5,343,520	1,411,791	1,371,633	3,971,887	55.18	71,981	1.35%
361	Structures & Improvements	4,372,006	1.12	4,896,647	1,354,850	1,316,312	3,580,335	50.63	70,716	1.62%
362	Station Equipment	83,664,562	1.07	89,521,081	18,549,279	18,021,648	71,499,433	26.16	2,733,159	3.27%
364	Poles, Towers, & Fixtures	180,551,331	1.30	234,716,730	68,606,654	66,655,150	168,061,580	19.82	8,479,394	4.70%
365	OH Conductor & Devices	179,538,721	0.94	168,766,398	33,083,601	32,142,543	136,623,855	20.90	6,537,027	3.64%
366	Underground Conduit	6,377,091	1.00	6,377,091	1,464,955	1,423,285	4,953,806	34.66	142,926	2.24%
367	Underground Conductor	9,812,956	1.13	11,088,640	1,655,544	1,608,452	9,480,188	37.43	253,278	2.58%
368	Line Transformers	119,012,919	1.01	120,203,048	28,150,578	27,349,840	92,853,208	19.15	4,848,731	4.07%
369	Services	53,900,363	1.38	74,382,501	17,054,558	16,569,444	57,813,057	15.41	3,751,658	6.96%
370	Meters	24,723,287	0.97	23,981,588	10,273,269	9,981,048	14,000,540	9.72	1,440,385	5.83%
371	Installations on Custs. Prem.	20,056,550	1.32	26,474,646	7,344,863	7,135,939	19,338,707	7.95	2,432,542	12.13%
373	Street Lighting & Signal Sys.	3,349,341	1.24	4,153,183	1,231,600	1,196,567	2,956,616	14.07	210,136	6.27%
	Total Distribution Plant	690,702,647	**1.11**	769,905,074	190,181,542	184,771,861	585,133,213	18.89	30,971,931	4.48%

KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

									Annual Accrual	
Acct. No.	Account Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Amount	Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
GENERAL PLANT										
389.1	Land Rights	37,384	1.00	37,384	11,898	6,909	30,475	51.13	596	1.59%
390	Structures & Improvements	19,811,669	1.00	19,811,669	9,535,669	5,537,254	14,274,415	18.15	786,469	3.97%
391	Office Furniture & Equipment	1,683,333	1.00	1,683,333	377,310	219,100	1,464,233	27.15	53,931	3.20%
392	Transportation Equipment	14,768	1.00	14,768	1,742	1,012	13,756	26.46	520	3.52%
393	Stores Equipment	164,548	1.00	164,548	60,496	35,129	129,419	18.97	6,822	4.15%
394	Tools Shop & Garage Equip.	3,553,696	1.09	3,873,529	1,042,908	605,604	3,267,925	21.92	149,084	4.20%
395	Laboratory Equipment	141,765	1.00	141,765	89,929	52,221	89,544	10.97	8,163	5.76%
396	Power Operated Equipment	5,931	1.00	5,931	2,728	1,584	4,347	13.50	322	5.43%
397	Communication Equipment	7,318,955	0.97	7,099,386	2,872,871	1,668,243	5,431,143	13.10	414,591	5.66%
398	Miscellaneous Equipment	1,065,616	1.03	1,097,584	464,407	269,676	827,908	11.54	71,743	6.73%
	Total General Plant	33,797,665	**1.00**	33,929,897	14,459,958	8,396,732	25,533,165	17.11	1,492,241	4.42%
	Total Depreciable Plant	2,662,852,388		2,349,437,375	716,258,352	958,037,055	1,684,592,231		94,052,594	3.53%

N/A = Not Applicable

Notes:

(1) The Company plans to retire Big Sandy Unit 2 at the end of May 2015 and the coal related portions of Unit 1 in 2016. Since the Commission authorized (Case No. 2012-00578) the Company to recover the coal-related portion of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and any other site related retirement costs, this depreciation recommends that the existing approved depreciation rates for Big Sandy Plant be retained until a future proceeding that includes the remaining portion of Big Sandy Unit 1 and the cost to re-power this unit to use natural gas.

(2) An annualized depreciation rate for Big Sandy Plant's SCR Catalyst was calculated using currently approved rates and included in the above analysis. A separate depreciation rate was calculated for Mitchell Plant's SCR Catalyst using AEP Air Emmissions Control estimated average life for the catalyst.

(3) Mitchell Plant cost at December 31, 2013. At December 31, 2013 the Mitchell Plant was jointly owned 50% by Kentucky Power Company and 50% by AEP Generating Resources and therefore the cost shown above is 50% of the total Mitchell Plant depreciable plant in service. The Mitchell Plant cost includes 50% of the investment in the gypsum plant underloader located at the Mountaineer Generating Station.

KENTUCKY POWER COMPANY
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013

ACCT. NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
STEAM PRODUCTION PLANT							
BIG SANDY PLANT (a)							
311	Structures & Improvements	43,291,665	3.78%	1,636,425	3.78%	1,636,425	0
312	Boiler Plant Equipment	362,456,070	3.78%	13,700,839	3.78%	13,700,839	0
312	Boiler Plant Equip SCR Catalyst	8,147,622	4.78%	389,456	4.78%	389,456	0
314	Turbogenerator Units	109,522,949	3.78%	4,139,967	3.78%	4,139,967	0
315	Accessory Electrical Equipment	16,513,202	3.78%	624,199	3.78%	624,199	0
316	Misc. Power Plant Equip.	8,709,178	3.78%	329,207	3.78%	329,207	0
	Total	548,640,686	3.79%	20,820,093	3.79%	20,820,093	0
MITCHELL PLANT - (b)							
311	Structures & Improvements	42,000,197	2.87%	1,205,406	2.74%	1,149,812	(55,594)
312	Boiler Plant Equipment	765,644,984	3.90%	29,860,154	3.13%	23,947,287	(5,912,867)
312	Boiler Plant Equip SCR Catalyst **(c)**	8,190,115	10.00%	819,012	12.50%	1,023,764	204,752
314	Turbogenerator Units	53,295,697	2.86%	1,524,257	1.84%	982,084	(542,173)
315	Accessory Electrical Equipment	17,080,672	2.39%	408,228	1.64%	280,242	(127,986)
316	Misc. Power Plant Equip.	7,693,412	2.79%	214,646	2.80%	215,335	689
	Total	893,905,077	3.81%	34,031,703	3.09%	27,598,524	(6,433,179)
	Total Steam Production Plant	**1,442,545,763**	**3.80%**	**54,851,796**	**3.36%**	**48,418,617**	**(6,433,179)**
TRANSMISSION PLANT							
350.1	Land Rights	26,456,147	1.71%	452,400	1.44%	381,850	(70,550)
352	Structures & Improvements	6,636,668	1.71%	113,487	2.08%	137,978	24,491
353	Station Equipment	170,843,671	1.71%	2,921,427	2.15%	3,669,309	747,882
354	Towers & Fixtures	94,517,543	1.71%	1,616,250	2.61%	2,464,522	848,272
355	Poles & Fixtures	74,696,720	1.71%	1,277,314	3.95%	2,949,685	1,672,371
356	OH Conductor & Devices	122,537,908	1.71%	2,095,398	2.91%	3,563,336	1,467,938
357	Underground Conduit	11,590	1.71%	198	2.99%	346	148
358	Underground Conductor & Devices	106,066	1.71%	1,814	2.62%	2,779	965
	Total Transmission Plant	**495,806,313**	**1.71%**	**8,478,288**	**2.66%**	**13,169,805**	**4,691,517**
DISTRIBUTION PLANT							
360.1	Land Rights	5,343,520	3.52%	188,092	1.35%	71,981	(116,111)
361	Structures & Improvements	4,372,006	3.52%	153,895	1.62%	70,716	(83,179)
362	Station Equipment	83,664,562	3.52%	2,944,993	3.27%	2,733,159	(211,834)
364	Poles, Towers, & Fixtures	180,551,331	3.52%	6,355,407	4.70%	8,479,394	2,123,987
365	Overhead Conductor & Devices	179,538,721	3.52%	6,319,763	3.64%	6,537,027	217,264
366	Underground Conduit	6,377,091	3.52%	224,474	2.24%	142,926	(81,548)
367	Underground Conductor	9,812,956	3.52%	345,416	2.58%	253,278	(92,138)
368	Line Transformers	119,012,919	3.52%	4,189,255	4.07%	4,848,731	659,476
369	Services	53,900,363	3.52%	1,897,293	6.96%	3,751,658	1,854,365
370	Meters	24,723,287	3.52%	870,260	5.83%	1,440,385	570,125
371	Installations on Custs. Prem.	20,056,550	3.52%	705,991	12.13%	2,432,542	1,726,551
373	Street Lighting & Signal Sys.	3,349,341	3.52%	117,897	6.27%	210,136	92,239
	Total Distribution Plant	**690,702,647**	**3.52%**	**24,312,736**	**4.48%**	**30,971,933**	**6,659,197**

KENTUCKY POWER COMPANY
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013

ACCT. NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
GENERAL PLANT							
389.1	Land Rights	37,384	2.54%	950	1.59%	596	(354)
390	Structures & Improvements	19,811,669	2.54%	503,216	3.97%	786,469	283,253
391	Office Furniture & Equipment	1,683,333	2.54%	42,757	3.20%	53,931	11,174
392	Transportation Equipment	14,768	2.54%	375	3.52%	520	145
393	Stores Equipment	164,548	2.54%	4,180	4.15%	6,822	2,642
394	Tools Shop & Garage Equipment	3,553,696	2.54%	90,264	4.20%	149,084	58,820
395	Laboratory Equipment	141,765	2.54%	3,601	5.76%	8,163	4,562
396	Power Operated Equipment	5,931	2.54%	151	5.43%	322	171
397	Communication Equipment	7,318,955	2.54%	185,901	5.66%	414,591	228,690
398	Miscellaneous Equipment	1,065,616	2.54%	27,067	6.73%	71,743	44,676
	Total General Plant	**33,797,665**	**2.54%**	**858,462**	**4.42%**	**1,492,241**	**633,779**
	Total Depreciable Plant	**2,662,852,388**	**3.32%**	**88,501,282**	**3.53%**	**94,052,596**	**5,551,314**

Notes:

(a) The depreciation study recommends that the current approved depreciation rates for Big Sandy Plant remain in effect until the next base case which will reflect the retirement of Big Sandy Unit 2 in 2015, the coal related portions of Unit 1 in 2016 and the cost to re-power Unit 1 to burn natural gas. Therefore there is no change in depreciation expense due to a change in depreciation rates for Big Sandy Plant.

(b) The current approved rates for Mitchell Generating Plant are from AEP affiliated company, Ohio Power Company as per the Order in Case No. 2012-00578.

(c) The depreciation rate was revised for the SCR catalyst at Mitchell Generating Station using AEP Generation's estimated average life for the catalyst of 8 years.

KENTUCKY POWER COMPANY
SCHEDULE III - COMPARISON OF MORTALITY CHARACTERISTICS
DEPRECIATION STUDY AS OF DECEMBER 31, 2013

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
		Existing Rates (See note, below)					Current Study Rates				
		Average Service Life (Years)	Iowa Curve	Salvage Factor	Cost of Removal Factor	Net Salvage Factor	Average Service Life (Years)	Iowa Curve	Salvage Factor	Cost of Removal Factor	Net Salvage Factor
TRANSMISSION PLANT											
350.1	Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
352.0	Structures & Improvements	55	S1.5	N/A	N/A	0%	60	S3.0	0%	10%	-10%
353.0	Station Equipment	50	R0.5	N/A	N/A	25%	50	L0.5	8%	11%	-3%
354.0	Towers & Fixtures	55	R4.0	N/A	N/A	0%	51	S6.0	3%	13%	-10%
355.0	Poles & Fixtures	45	R3.0	N/A	N/A	0%	43	L3.0	2%	63%	-61%
356.0	Overhead Conductor & Devices	50	R3.0	N/A	N/A	10%	50	S6.0	6%	33%	-27%
357.0	Underground Conduit	37	R2.0	N/A	N/A	0%	37	R2.0	0%	0%	0%
358.0	Underground Conductor and Devices	44	R1.0	N/A	N/A	0%	44	R1.0	0%	0%	0%
DISTRIBUTION PLANT											
360.1	Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
361.0	Structures & Improvements	65	L0.5	N/A	N/A	0%	70	R2.0	4%	16%	-12%
362.0	Station Equipment	25	L0.0	N/A	N/A	25%	33	R0.5	10%	17%	-7%
364.0	Poles, Towers, & Fixtures	28	L0.0	N/A	N/A	25%	28	R0.5	18%	48%	-30%
365.0	Overhead Conductor & Devices	26	R1.5	N/A	N/A	25%	26	L0.0	30%	24%	6%
366.0	Underground Conduit	37	R2.0	N/A	N/A	0%	45	R3.0	0%	0%	0%
367.0	Underground Conductor	44	R1.0	N/A	N/A	0%	44	R0.5	1%	14%	-13%
368.0	Line Transformers	25	R1.5	N/A	N/A	15%	25	L0.0	29%	30%	-1%
369.0	Services	18	R2.0	N/A	N/A	0%	20	L0.0	1%	39%	-38%
370.0	Meters	27	R0.5	N/A	N/A	0%	17	R4.0	22%	19%	3%
371.0	Installations on Custs. Prem.	11	L0.0	N/A	N/A	30%	11	L0.0	1%	33%	-32%
373.0	Street Lighting & Signal Sys.	15	L0.0	N/A	N/A	15%	20	L0.0	1%	25%	-24%
GENERAL PLANT											
389.1	Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
390.0	Structures & Improvements	45	L3.0	N/A	N/A	0%	35	L2.0	1%	1%	0%
391.0	Office Furniture & Equipment	35	R0.5	N/A	N/A	10%	35	SQ	0%	0%	0%
392.0	Transportation Equipment	30	R3.0	N/A	N/A	0%	30	SQ	0%	0%	0%
393.0	Stores Equipment	30	R1.0	N/A	N/A	0%	30	SQ	0%	0%	0%
394.0	Tools Shop & Garage Equipment	30	R0.5	N/A	N/A	0%	30	SQ	0%	9%	-9%
395.0	Laboratory Equipment	30	L5.0	N/A	N/A	0%	30	SQ	0%	0%	0%
396.0	Power Operated Equipment	N/A	N/A	N/A	N/A	N/A	25	SQ	0%	0%	0%
397.0	Communication Equipment	22	L3.0	N/A	N/A	0%	22	SQ	6%	3%	3%
398.0	Miscellaneous Equipment	20	S5.0	N/A	N/A	0%	20	SQ	0%	3%	-3%

Note: Kentucky Power Company's existing depreciation rates are from Case No. 91-066. No detail of Cost of Removal % and Salvage Factor % is available from the order from that Case.

Mitchell Plant Unit 1 & 2

CONCEPTUAL DEMOLITION COST ESTIMATE

Prepared for:
American Electric Power

Project No. 11488-066
March 20, 2013
Revision 0

55 East Monroe Street
Chicago, IL 60603-5780 USA

Issue Summary Page

Revision Number	Date	Purpose	Prepared By	Reviewed By	Approved By	Pages Affected
A	02/22/13	Comments	R. Kinsinger	J. A. Evanchik D. F. Franczak		All
0	03/20/13	Use	R. Kinsinger	J. A. Evanchik D. F. Franczak	S. R. Bertheau	All

TABLE OF CONTENTS

1.0 INTRODUCTION

The Mitchell Plant is located near Moundsville, West Virginia in Marshall County. The plant consists of two (2) generating units with a total generating capacity of 1,632 megawatts (816, MW per unit). Units 1 & 2 were placed in operation in 1971.

American Electric Power (AEP) recently contracted Sargent & Lundy, LLC. (S&L) to prepare a conceptual demolition cost estimate using 1st Quarter 2013 pricing levels. The objective of the conceptual demolition cost estimate is to determine the gross demolition costs for Mitchell Plant Units 1 and 2 (including gross salvage credits and any other benefits). The cost estimate considers the demolition/dismantlement methodology which complies with current OSHA rules and regulations.

2.0 COST ESTIMATE SUMMARY

Conceptual Demolition Cost Estimate No. 31982B, dated March 20, 2013, was prepared and is included as Exhibit 1. The cost estimate is structured into a code of accounts as identified in Table 2-1.

Table 2-1
Cost Estimate Code of Accounts

Account Number	Description
10	Demolition Costs (including steel, equipment & piping scrap value)
18	Scrap Value Costs
91	Other Direct & Construction Indirect Costs
93	Indirect Costs
94	Contingency Costs
96	Escalation Costs

The results of the cost estimate are provided in Table 2-2 below:

Table 2-2
Cost Estimate Results Summary

Description	Total Cost
Demolition Cost	$62,531,960
Scrap Value	$(38,063,765)
Direct Cost Subtotal	$24,468,195
Indirect Cost	$ 2,446,800
Contingency Cost	$15,456,400
Total Project Cost	$42,371,395

3.0 TECHNICAL BASIS

The scope of dismantlement includes the complete Mitchell Plant Units 1 & 2 generating facility and plant common services associated with both units. Common facilities include:

- 1,200 ft Chimney
- 1,000 ft Chimney
- Various Buildings
- FGD Common Equipment

The following are excluded from the scope of the conceptual demolition cost estimate.

- Bottom Ash Pond
- Asbestos Removal
- Switchyard

The scope of the demolition cost estimate is based on a review of the facility by two (2) S&L employees conducted in January 2013 for development of the demolition cost estimate.

4.0 COMMERCIAL BASIS

4.1 General Information

The Conceptual Demolition Cost Estimate prepared for the Mitchell Plant is a conceptual estimate of the cost to dismantle Mitchell Plant Units 1 and 2.

Costs were calculated for (1) demolition of existing plant structures and equipment and associated site restoration costs, (2) scrap value of steel and copper, (3) associated indirect costs, and (4) contingency. All units used in the cost estimate are U.S. Standard and all costs are in US Dollars (1st Quarter 2013 levels). A two (2) year demolition schedule is anticipated not including asbestos removal (to be performed prior to start of demolition work).

4.2 Quantities/Material Cost

Quantities of pieces of equipment and/or bulk material commodities used in this cost estimate were intended to be reasonable and representative of projects of this type. Material quantities were estimated from the site plot plan and other drawings and data provided by AEP and Plant Personnel.

4.3 Construction Labor Wages

Craft labor rates (Craft Hourly Rate) for the cost estimate were calculated as Non-Union West Virginia Craft Labor rates based on Personnel Administration Services (PAS) Inc. "2013 Merit Shop Wage and Benefit Survey". The craft rates were incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew hourly rates detailed in the cost estimate. A 1.00 regional labor productivity multiplier was included based on Compass International Global Construction Yearbook, 2013 Edition, for non-union work in West Virginia.

4.3.1 Labor Work Schedule and Incentives

The estimate assumed a 5x8 work week. No other labor incentives are included.

4.3.2 Construction Indirects

Allowances were included in the cost estimate as direct costs as noted for the following:

- Freight: Material and scrap freight included in the material and scrap costs.

- Additional Crane Allowance: None included. Cost of cranes and construction machinery are included in the labor wage rates.
- Mobilization and Demobilization: Included in labor wage rates.
- Scaffolding: Included in labor wage rates.
- Consumables: Included in material and labor costs.
- Per Diem Costs: Excluded from the estimate.
- Contractor's General and Administrative Costs and Profit: Included in the labor wage rates.

4.4 Scrap Value

The value of scrap was determined by a 12 month average (March 2012 through February of 2013) using Zone 4 (USA Midwest) of the "Scrap Metals Market Watch" (www.americanrecycler.com).
Since the values obtained are delivered pieces, 10% of the values obtained were deducted to pay for separation, preparation and shipping to the mills. This resulted in realized prices of:

- Mixed Steel Value @ $287/Ton
- Copper Value @ $6,091/Ton
- Stainless Steel @ $1,336/Ton

Note: 1 Ton = 2,000 Lbs

All steel is considered to be mixed steel unless otherwise noted.

4.5 Indirect Costs

Allowances were included in the cost estimate as indirect costs as noted for the following:

- Engineering, Procurement and Project Services: None included.
- Construction Management Support: None included.
- Owners Cost: Included as 10.0% of the total direct cost. Owners Costs include owner project engineering, administration and construction management, permits and fees, legal expenses, taxes, etc.

4.6 Escalation

No allowance for escalation was included in the cost estimate. All costs are determined in 1st Quarter 2013 levels.

4.7 Contingency

Allowances were included in the cost estimate as contingency as noted for the following:

- Scrap Value: Included as a 15.0% reduction in the salvage value resulting in a total net reduction in the salvage value. The contingency assumes a potential drop in salvage value thus increasing the project cost.
- Material: Included as 15.0% of the total material cost.
- Labor: Included as 15.0% of the total labor cost.
- Indirect: Included as 15.0% of the total indirect cost.

4.8 Assumptions

The following assumptions apply to the cost estimate.

- All chemicals will be removed by the Owner prior to demolition, from the facilities to be demolished.
- All coal and fuel oil will be consumed prior to demolition.
- Catalyst, if any, is assumed to be removed and returned to the OEM by others, prior to demolition.
- All electrical equipment and wiring is de-energized prior to start of dismantlement.
- No extraordinary environmental costs for demolition have been included. Removal of five (5) feet of fill inside the bermed areas around the oil tanks and metal cleaning waste tank is included.
- Asbestos and PCB's are removed from site by others prior to start of demolition.
- Bottom Ash Pond is not included. These costs will be determined by the Owner.
- Demolition of the two (2) chimneys will be subcontracted. One chimney is 1,200 ft high and the second is 1,000 ft high. The 1,200 ft chimney is approximately 200 ft from WV Route 2 and the 1,000 ft chimney is approximately 600 ft from the same road. Also, in the opposite direction the 1,200 ft chimney is approximately 1,500 ft from the Ohio River and the 1,000 ft chimney is approximately 1,250 ft from the river. Therefore Careful Demolition (top down demolition process) will be used to dismantle the chimneys as opposed to explosive demolition (which can scatter debris onto the road and into the river). Each chimney is demolished by breaking it up from the top and dropping the debris down the throat of the chimney and removing the debris periodically through the duct openings on the sides of the chimney (located 75 to 100 ft above grade). The remaining portion of the chimney below the duct openings is then demolished as any other structure.

- Switchyards within the plant boundaries are not part of the scope, neither are access roads to these facilities. Fences and gates needed to protect the switchyard will be left in place. The other site fences are removed.

- All items above grade and to a depth of 2 foot will be demolished. Any other items buried more than 2 foot will remain in place. All foundations are removed and buried on site with the exception of power block (turbine building, boiler building and service building), FGD building, limestone preparation building, gypsum dewatering building and the two (2) chimney thick mat foundations at grade. These foundations will have two (2) feet of soil spread over them and will be graded into the surrounding area.

- Underground piping, conduit and cable ducts will be abandoned in place.

- Underground piping larger than 4 feet diameter will be filled with sand or slurry and capped at the ends to prevent collapse. Non-metal pipe will be collapsed.

- All demolished materials are considered debris, except for organic combustibles and non-embedded metals which have scrap value.

- The basis for salvage estimating is for scrap value only. No resale of equipment or material is included.

- Handling, on-site and off-site disposal of hazardous materials would be performed in compliance with methods approved by Owner.

- Disturbed areas will be buried under 2 feet of topsoil mulched and seeded with grass – no other landscaping is included.

- All borrow material is assumed to be purchased from nearby (10 mile round trip) offsite sources.

- Debris not suitable for burial is to be disposed of off-site. Assumed distance to final disposal is within a 5 mile haul.

5.0 REFERENCES

Drawings utilized in the preparation of this demolition cost estimate are identified in Table 5-1.

Table 5-1

Reference Drawings

Unit	Document Number	Revision	Title
12	E-1000	1	34.5KV & Coal Handling-1000
12	E-1100	0	Fish Creek Station 69KV/34.5KV One Line Diagram & Protection
12	1200D	23	Coal Handling Barge Unloading Auxiliary One-Line Diagram
12	1200E	16	Coal Handling Auxiliary One-Line Diagram.
12	1200H	1	Coal Handling Auxiliary One-Line Diagram Car Thawing
12	121001	3	FGD One Line Diagram
12	121102	4	Electrical 138-13.8 KV Substation Line 2 Bus B One Line Diagram
12	121020	5	Dry Sorbent 13.8kv Auxiliary One Line Diagram
12	121101	4	Electrical 138-13.8 KV Substation Line 1 Bus A One Line Diagram
12	50008	8	General Arrangement Precipitator Install Comp Plan Below El. 676-0
12	50009	4	General Arrangement Precipitator Install Plan Above El 676-0
12	50012	3	General Arrangement Precipitator Access & Rectifier Removal
12	5028A	0	Arrangement And Details Feeder Down Spout Unit 1 And 2
12	5030	16	Plot Plan
12	5031	2	General Cross Sects
12	5032	1	General Cross Sects @ General
12	5034	2	Long Sects Thru Heater Bay
12	5035	1	Long Sects Thru Steam General
12	5036	1	Cross Sects Pulv Bay
12	5041	2	Plans Heater Bay & Steam General El. 58-0, 70-0, & 80-0
12	5042	2	Slag Blower Platforms - Heater Bay And Turbine Room Roof
12	5043	1	Plans Deaer & Upper Level Slag Blowers Platform
12	5044	1	Comp Main Floor
12	5044A	0	Property Plan & Ash Storage Area
12	5044B	2	Equipment Location - Conners Run Pump House
12	5070000A	1	Site Layout
12	5070000A	0	General Arrangement FGD Building El. 667'-0"
12	5070000B	0	General Arrangement FGD Building El. 705'-0"
12	5070000C	0	General Arrangement FGD Building El. 720'-0"
12	5070000D	0	General Arrangement FGD Building El. 743'-0"
12	5070000E	0	General Arrangement FGD Building El. 755'-2 1/2"
12	5070000F	0	General Arrangement FGD Building El. 776'-3"
12	5070000G	0	General Arrangement FGD Building El. 798'-0 1/2"
12	5070000H	0	General Arrangement FGD Building Elevation Looking East
12	5070000I	0	General Arrangement FGD Building Elevation Looking North
12	5070000J	0	General Arrangement FGD Building Laboratory
12	5070001A	0	General Arrangement Dewatering Area El. 667'-0"
12	5070001B	0	General Arrangement Dewatering Area El. 695'-0"
12	5070001C	0	General Arrangement Dewatering Area El. 729'-6"

Unit	Document Number	Revision	Title
12	5070001D	0	General Arrangement Dewatering Area El. 757'-4" & El. 781'-0"
12	5070001E	0	General Arrangement Dewatering Area Elevation Looking North
12	5070002A	0	General Arrangement Reagent Prep Area El. 667'-0"
12	5070002B	0	General Arrangement Reagent Prep Area El. 705'-1 1/4"
12	5070002C	0	General Arrangement Reagent Prep Area El. 729'-6" & El 784'-2"
12	5070003	0	General Arrangement Urea U2a Area
12	5070006	0	General Arrangement Service Water Area Plan View
12	5070007	0	General Arrangement Existing Aux Boiler Stack Relocation
12	5070007A	0	Elevation Auxilliary Boiler Stack Relocations
12	5070008A	1	General Arrangement Dry Solid Sorbent System Enlarged Plan
12	5070008B	0	General Arrangement Dry Solid Sorbent System Section A-A
12	5070008C	0	General Arrangement Dry Sorbent System Overall Plan
12	5070008D	0	General Arrangement Dry Solid Sorbent System Section B-B
12	5070009	0	General Arrangement Coal Blending System Plan
12	5070010	0	General Arrangement Gypsum Conveyors To Wallboard Plant
12	5078000B	2	Hydraulic Profile
12	5078000C	2	Key Plan
12	5078000J	2	Piperack Enlarged Lower Plan
12	5078000K	2	Piperack Enlarged Middle Plan
12	5078000L	2	Piperack Enlarged Upper Plan
12	12-5080022	1	General Arrangement FGD Reagent Prep Area Ground Floor El 667'-0"
12	12-5080023	1	General Arrangement FGD Reagent Prep Area Plan At El. 681'-6-1/4"
12	12-5080024	1	General Arrangement FGD Reagent Prep Area Plan At Platform El 705'-1 1/4"
12	12-5080025	1	General Arrangement FGD Reagent Prep Area Plan At Platform El 741'-1 1/4"
12	12-5080026	1	General Arrangement FGD Reagent Prep Area Front Section F1-F1
12	12-5080027	1	General Arrangement FGD Reagent Prep Area Front Section F2-F2
12	12-5080028	1	General Arrangement FGD Reagent Prep Area Front Section F3-F3
12	12-5080029	1	General Arrangement FGD Reagent Prep Area Front Section F4-F4
12	12-5080030	1	General Arrangement FGD Reagent Prep Area Side Section S1-S1
12	12-5080031	1	General Arrangement FGD Reagent Prep Area Side Section S2-S2
12	5080074	2	General Arrangement FGD Byproduct Dwt Area Side Section S3-S3
12	5080302	0	Design Arrangement Abs Area Pipe Ground Floor To El 692'-0"
12	548839E	1	General Arrangement FGD Maintenance Storage Area Ground Floor To El 667'-0"
12	549320E	2	Erection Arrangement Drb-4z Pc Fired Burner CW
12	549321E	2	Erection Arrangement Drb-4z Pc Fired Burner CW
12	549322E	2	Erection Arrangement Drb-4z Pc Fired Burner CW
12	549323E	2	Erection Arrangement Drb-4z Pc Fired Burner CW

Unit	Document Number	Revision	Title
12	71002-MA-0-5090100	0	SCR System Equipment Arrangement Plan
1	1200A1	20	Aux One Line Diagram Sheet 1 Of 2
1	1200A2	20	Aux One Line Diagram Sheet 2 Of 2
1	12001	5	Precipitator Auxiliary 0ne-Line
1	12002	5	Precipitator Equip Power Dist Aux One-Line Diagram
1	121002	2	Unit 1 FGD 13.8kv - 4.16kv Auxiliary One Line Diagram
1	50003	7	Fly Ash Removal Wet System Unit 1
1	50010	2	General Arrangement Precipitator Install Sections
1	5033	2	Long Sects Thru Turbine Room
1	5037	6	Basement Plan Elevation 1' -0' Unit 1
1	5038	3	Miscellaneous Fl & Platform Below Main Floor
1	5039	2	Main Fl Plan El 36-0
1	5040	2	Heater Bay & Steam Gen El 46'0" 48'0" & 52'6"
1	5090000	2	SCR General Arrangement Elevation A/10 Looking South
1	5090001	2	SCR General Arrangement Elevation B/11 Looking West
1	5090002	2	SCR General Arrangement Elevation C/12 Looking East
1	5090003	1	SCR General Arrangement Elevation D/13 Looking West
1	5090004	2	SCR General Arrangement Elevation H/14 & J/14 Center and Outbound Return Ducts
1	5090005	1	SCR General Arrangement Plan View E/20
1	5090006	2	SCR General Arrangement Plan View F/21
1	5090007	2	SCR General Arrangement Plan View G/22
1	5090008	1	SCR General Arrangement Plan View H/23
2	1200A2	19	Aux One Line Diagram Sheet 2 Of 2
2	1200A1	19	Aux One Line Diagram Sheet 1 Of 2
2	121003	3	Unit 2 FGD 13.8kv - 4.16kv Auxiliary One Line Diagram
2	50011	2	General Arrangement Precipitator Install Sections
2	50014	0	Arrangement FGD Fan Room New Motors & Rotors
2	5033	1	Long Sects Thru Turbine Room
2	5037	3	Basement Plan Elevation 1" - 0"
2	5038	2	Miscellaneous Floors & Platform Below Main Floor
2	5039	3	Main Floor Plan El 36-0
2	5040	2	Heater Bay & Steam Generator El 46-0; 48-0 & 52-6
2	5090000	1	SCR General Arrangement Elevation A/10 Looking South
2	5090001	1	SCR General Arrangement Elevation B/11 Looking West
2	5090002	1	SCR General Arrangement Elevation C/12 Looking East
2	5090003	1	SCR General Arrangement Elevation D/13 Looking West
2	5090005	1	SCR General Arrangement Plan View E/20
2	5090006	1	SCR General Arrangement Plan View F/21
2	5090007	1	SCR General Arrangement Plan View G/22
2	5090008	1	SCR General Arrangement Plan View H/23

12 = Common For Units 1 & 2

1 = Unit 1

2 = Unit 2

EXHIBIT 1
Mitchell Plant Units 1 & 2
Conceptual Demolition Cost Estimate No. 31982B

AMERICAN ELECTRIC POWER
Decommissioning Study Mitchell Plant
Units 1, 2 and Common Facilities

Project name	Mitchell Plant
Estimator	RCK
Labor rate table	13NUWV
Project No.	11488-066
Station Name	Mitchell Plant
Unit	1, 2 and Common
Location	West Virginia
Product Factor	1
Price Level	2013
Issue Date	3/20/2013
Estimate Date	3/14/2013
Reviewed By	JAE
Approved By	MNO
Status	*Comments*
Estimate No.	31982B
Estimate Class	Conceptual
Cost index	NUWV

Estimate Totals

Description	Amount	Totals	Hours		Percent of Total	
LABOR	46,995,884		589,630.602	hrs	110.91%	
MATERIAL	11,136,076				26.28%	
SUBCONTRACT	4,400,000				10.38%	
SCRAP RECOVERY	(38,063,765)				-89.83%	
	24,468,195	**24,468,195**			**57.75**	**57.75%**
91-1 SCAFFOLDING						
91-2 OT WORKING 5-10 HOUR DAYS						
91-3 OT Working 7-10 Hr Days						
91-2 PER DIEM						
91-5 CONSUMABLES						
91-6 FREIGHT ON EQUIPMENT						
91-7 FREIGHT ON SPECIAL EQUIP.						
91-8 FREIGHT ON MATERIAL						
91-9 FREIGHT ON SCRAP INCL						
91-10 SALES TAX						
91-11 CONTRACTOR'S G&A EXPENSE						
91-12 CONTRACTOR'S PROFIT						
		24,468,195				**57.75%**
93-1 EP&P SERVICES						
93-2 CM SUPPORT						
93-3 START-UP/COMMISSIONING						
93-4 START-UP/SPARE PARTS						
93-5 EXCESS LIABILITY INSUR.						
93-6 SALES TAX ON INDIRECTS						
93-7 OWNER'S COST	2,446,800				5.77%	
93-8 EPC FEE						
	2,446,800	**26,914,995**			**5.77**	**63.52%**
94-3 CONTINGENCY ON MATERIAL	1,670,400				3.94%	
94-4 CONTINGENCY ON LABOR	7,049,400				16.64%	
94-5 CONTINGENCY ON SUB.	660,000				1.56%	
94-6 CONTINGENCY ON SCRAP	5,709,600				13.48%	
94-7 CONTINGENCY ON INDIRECTS	367,000				0.87%	
	15,456,400	**42,371,395**			**36.48**	**100.00%**
96-3 ESCALATION ON MATERIAL						
96-4 ESCALATION ON LABOR						
96-5 ESCALATION ON SUB.						
96-6 ESCALATION ON SCRAP						
96-7 ESCALATION ON INDIRECTS						
		42,371,395				**100.00%**
98 INTEREST DURING CONSTR.						
		42,371,395				**100.00%**
Total		***42,371,395***				

Area	Group	DESCRIPTION	LABOR MAN HRS	LABOR AMOUNT	MATERIAL AMOUNT	SUB AMOUNT	PROCESS EQUIP AMOUNT	TOTAL AMOUNT
Common								
	10.00.00	WHOLE PLANT DEMOLITION	211,270	19,483,672	11,020,976	4,400,000		34,904,648
	18.00.00	SCRAP VALUE					(8,643,497)	(8,643,497)
		Common	**211,270**	**19,483,672**	**11,020,976**	**4,400,000**	**(8,643,497)**	**26,261,150**
Unit 1								
	10.00.00	WHOLE PLANT DEMOLITION	190,383	13,835,429	57,550			13,892,979
	18.00.00	SCRAP VALUE					(14,999,173)	(14,999,173)
		Unit 1	**190,383**	**13,835,429**	**57,550**		**(14,999,173)**	**(1,106,194)**
Unit 2								
	10.00.00	WHOLE PLANT DEMOLITION	187,978	13,676,784	57,550			13,734,334
	18.00.00	SCRAP VALUE					(14,421,095)	(14,421,095)
		Unit 2	**187,978**	**13,676,784**	**57,550**		**(14,421,095)**	**(686,761)**

Area	Group	Phase	Description	Notes	Quantity	Man Hours	Crew Rate	Labor Cost	Material Cost	Subcontract Cost	Process Equipment Cost	Total Cost
Common												
	10.00.00		**WHOLE PLANT DEMOLITION**									
		10.21.00	**CIVIL WORK**									
			COVERED DISTURBED AREAS OF SITE W/2 FT TOPSOIL	OFFSITE SUPPLY	438,827.00 CY	21,941	101.99 /MH	2,237,798	10,531,848	-	-	12,769,646
			SEED AND MULCH		136.00 AC	3,672	33.72 /MH	123,820	379,168	-	-	502,988
			PAVED SURFACES	LEAVE ROAD TO SWITCHYARD	8,900.00 SY	1,068	101.99 /MH	108,925		-	-	108,925
			DEMOLITION - 228000 TRACK FEET of 110# RAILROAD TRACK		228,000.00 TF	68,400	101.99 /MH	6,976,116		-	-	6,976,116
			DEMOLITION - PULL SHEET PILE & CAP FOR BARGE CELLS		654.00 TN	1,766	101.99 /MH	180,094		-	-	180,094
			DEMOLITION - PERIMETER FENCE	LEAVE SWITCHYARD FENCES	15,600.00 LF	624	101.99 /MH	63,642		-	-	63,642
			CIVIL WORK			**97,471**		**9,690,395**	**10,911,016**			**20,601,411**
		10.22.00	**CONCRETE**									
			BUILDING PAD FOUNDATION 110LB/CY, OUTBUILDINGS & MISC FDNS		6,600.00 CY	7,425	75.99 /MH	564,226		-	-	564,226
			EQUIPMENT FOUNDATION110 LB/CY, MISC EQUIPMENT		1,300.00 CY	1,321	75.99 /MH	100,368		-	-	100,368
			INTAKE CLOSURE	GROUT OR SAND FILL	800.00 CY	800	75.99 /MH	60,792	73,600	-	-	134,392
			DEMOLITION, CONCRETE - REMOVE BARGE CELL PILE CAPS		780.00 CY	1,404	75.99 /MH	106,690		-	-	106,690
			CONCRETE			**10,950**		**832,075**	**73,600**			**905,675**
		10.24.00	**ARCHITECTURAL**									
			BUILDING, FGD BLDG		2,100,000.00 CF	12,600	75.09 /MH	946,134		-	-	946,134
			BUILDING, DEWATERING AREA BLDG		800,000.00 CF	4,800	75.09 /MH	360,432		-	-	360,432
			BUILDING, REAGENT PREP AREA		830,000.00 CF	4,980	75.09 /MH	373,948		-	-	373,948
			BUILDING, SERVICE BLDG		1,040,400.00 CF	12,485	75.09 /MH	937,484		-	-	937,484
			BUILDING, CEMS BLDG		1,000.00 CF	6	75.09 /MH	451		-	-	451
			BUILDING, GYPSUM STORAGE BLDG		2,160,000.00 CF	12,960	75.09 /MH	973,166		-	-	973,166
			BUILDING, RELOCATED WAREHOUSE		39,600.00 CF	238	75.09 /MH	17,841		-	-	17,841
			BUILDING, MAINTENANCE SLURRY BLDG		10,032.00 CF	60	75.09 /MH	4,520		-	-	4,520
			BUILDING, CONSTRUCTION FACILITIES BLDG		184,800.00 CF	1,109	75.09 /MH	83,260		-	-	83,260
			BUILDING, ID FAN ELECTRICAL BLDG		19,600.00 CF	118	75.09 /MH	8,831		-	-	8,831
			BUILDING, RELOCATED ELECTRICAL BLDG		10,500.00 CF	63	75.09 /MH	4,731		-	-	4,731
			BUILDING, UREA UNLOADING BLDG		10,368.00 CF	62	75.09 /MH	4,671		-	-	4,671
			BUILDING, UREA HYDOLIZER & TANK BLDG		265,200.00 CF	1,591	75.09 /MH	119,483		-	-	119,483
			BUILDING, CPS TREATMENT BLDG		918,000.00 CF	5,508	75.09 /MH	413,596		-	-	413,596
			BUILDING, CPS WASTE TRANSFER HOUSE		20,000.00 CF	120	75.09 /MH	9,011		-	-	9,011
			BUILDING, RIVER WATER MAKEUP PUMP HOUSE		32,000.00 CF	192	75.09 /MH	14,417		-	-	14,417
			BUILDING, PRECIPITATOR PARTS WAREDHOUSE		266,000.00 CF	1,596	75.09 /MH	119,844		-	-	119,844
			BUILDING, TRACTOR SHED		72,000.00 CF	432	75.09 /MH	32,439		-	-	32,439
			BUILDING, HEAVY EQUIPMENT STORAGE BLDG		208,000.00 CF	1,248	75.09 /MH	93,712		-	-	93,712
			BUILDING, DELUGE VALVE BLDG		1,000.00 CF	6	75.09 /MH	451		-	-	451
			BUILDING, EXISTING CONSOL TRANSFER STATION #1		64,800.00 CF	389	75.09 /MH	29,195		-	-	29,195
			BUILDING, STATION HTS-3		31,200.00 CF	187	75.09 /MH	14,057		-	-	14,057
			BUILDING, STATION HTS-2B		56,000.00 CF	336	75.09 /MH	25,230		-	-	25,230
			BUILDING, STATION HTS-2A		96,000.00 CF	576	75.09 /MH	43,252		-	-	43,252
			BUILDING, COAL BLENDING SYSTEM ELECTRICAL ROOM		9,600.00 CF	58	75.09 /MH	4,325		-	-	4,325
			BUILDING, UTILITY SHOWER BLDG		65,450.00 CF	393	75.09 /MH	29,488		-	-	29,488
			BUILDING, TRAINING CENTER		50,400.00 CF	302	75.09 /MH	22,707		-	-	22,707
			BUILDING, MAIN GATE HOUSE		4,800.00 CF	29	75.09 /MH	2,163		-	-	2,163
			BUILDING, CONTROL ROOM SIMULATOR BLDG		73,500.00 CF	441	75.09 /MH	33,115		-	-	33,115
			BUILDING, SOUTH WARE HOUSE COMPLEX - 4 WAREHOUSES		414,050.00 CF	2,484	75.09 /MH	186,546		-	-	186,546
			ARCHITECTURAL			**65,368**		**4,908,498**				**4,908,498**
		10.25.00	**CONCRETE CHIMNEY & STACK**									
			1200' TALL CONCRETE CHIMNEY	PRICE SHOWN IS SUBCONTRACTED PRICE	1,200.00 VLF		75.99 /MH			2,400,000	-	2,400,000
			1000' TALL CONCRETE CHIMNEY	PRICE SHOWN IS SUBCONTRACTED PRICE	1,000.00 VLF		75.99 /MH			2,000,000	-	2,000,000
			CONCRETE CHIMNEY & STACK							**4,400,000**		**4,400,000**
		10.31.00	**MECHANICAL EQUIPMENT**									
			TANK, DEWATERING HYDOCLONE FEED TANK A, 850,800 GALLON	61'6' DIA X 63' HIGH	123.00 TN	329	65.69 /MH	21,589		-	-	21,589

Area	Group	Phase	Description	Notes	Quantity	Man Hours	Crew Rate	Labor Cost	Material Cost	Subcontract Cost	Process Equipment Cost	Total Cost
		10.31.00	MECHANICAL EQUIPMENT									
			TANK, DEWATERING HYDOCLONE FEED TANK B, 850,800 GALLON	61'6' DIA X 63' HIGH	123.00 TN	329	65.69 /MH	21,589		-	-	21,589
			TANK, RECLAIM WATER TANK A, 351,000 GALLONS	45' DIA X 58' HIGH	60.00 TN	160	65.69 /MH	10,531		-	-	10,531
			TANK, RECLAIM WATER TANK B, 351,000 GALLONS	45' DIA X 58' HIGH	60.00 TN	160	65.69 /MH	10,531		-	-	10,531
			TANK, REAGENT SLURRY STORAGE TANK A, 457,920 GALLONS	50' DIA. X 50' HIGH	64.00 TN	171	65.69 /MH	11,234		-	-	11,234
			TANK, REAGENT SLURRY STORAGE TANK B, 457,920 GALLONS	50' DIA. X 50' HIGH	64.00 TN	171	65.69 /MH	11,234		-	-	11,234
			TANK, MAINTENANCE STORAGE TANK, 1,417,000 GALLONS	61'6" DIA X 67' TALL	129.00 TN	345	65.69 /MH	22,643		-	-	22,643
			TANK, FGD SERVICE WATER TANK, 399,480 GALLONS	36'6" DIA X 58'6" HIGH	37.00 TN	99	65.69 /MH	6,494		-	-	6,494
			TANK, UREA FEED TANK, 200,000 GALLONS	35' DIA X 30' HIGH	25.00 TN	67	65.69 /MH	4,388		-	-	4,388
			TANK, FUEL OIL STORAGE TANK, 500,000 GALLONS	52' DIA X 32' HIGH	50.00 TN	134	65.69 /MH	8,776		-	-	8,776
			TANKS, FUEL OIL STORAGE TANK, 1,500,000 GALLONS	80' DIA X 42' HIGH	131.00 TN	350	65.69 /MH	22,994		-	-	22,994
			TANK, METAL CLEANING WASTE TREATMENT TANK, 1,000,000 GALLONS	70' DIA X 35' HIGH	83.00 TN	222	65.69 /MH	14,568		-	-	14,568
			MECHANICAL EQUIPMENT - FGD EQUIPMENT		646.00 TN	1,308	65.69 /MH	85,932		-	-	85,932
			MECHANICAL EQUIPMENT - DRY SORBENT SYSTEM		100.00 TN	203	65.69 /MH	13,302		-	-	13,302
			MECHANICAL EQUIPMENT			4,046		265,807				265,807
		10.33.00	MATERIAL HANDLING EQUIPMENT									
			MATERIAL HANDLING EQUIPMENT - LIMESTONE/GYPSUM GYPSUM CLAMSHELL UNLOADER		400.00 TN	810	65.69 /MH	53,209		-	-	53,209
			MATERIAL HANDLING EQUIPMENT - LIMESTONE//GYPSUM BUCKET BARGE UNLOADER		400.00 TN	810	65.69 /MH	53,209		-	-	53,209
			MATERIAL HANDLING EQUIPMENT - COAL BUCKET BARGE UNLOADER		400.00 TN	810	65.69 /MH	53,209		-	-	53,209
			MATERIAL HANDLING EQUIPMENT - GYPSUM HANDLING SYSTEM		2,152.00 TN	4,358	65.69 /MH	286,264		-	-	286,264
			MATERIAL HANDLING EQUIPMENT - LIMESTONE HANDLING SYSTEM		733.00 TN	1,484	65.69 /MH	97,505		-	-	97,505
			MATERIAL HANDLING EQUIPMENT - COAL HANDLING SYSTEM		2,300.00 TN	4,658	65.69 /MH	305,951		-	-	305,951
			MATERIAL HANDLING EQUIPMENT - COAL HANDLING SYSTEM - COAL BLENDING SYSTEM		944.00 TN	1,912	65.69 /MH	125,573		-	-	125,573
			MATERIAL HANDLING EQUIPMENT			14,841		974,920				974,920
		10.35.00	PIPING									
			PIPING - CIRC WATER PIPING AND TUNNELS		1.00 LS	1,020	75.99 /MH	77,510		-	-	77,510
			PIPING - DEMO BOP PIPING AND HANGERS		1.00 LS	509	65.69 /MH	33,436		-	-	33,436
			PIPING			1,529		110,946				110,946
		10.41.00	ELECTRICAL EQUIPMENT									
			MISCELLANEOUS ELECTRICAL EQUIPMENT		100.00 TN	267	65.69 /MH	17,552		-	-	17,552
			MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS		406.60 TN	1,086	65.69 /MH	71,368		-	-	71,368
			ELECTRICAL EQUIPMENT			1,354		88,920				88,920
		10.42.00	RACEWAY, CABLE TRAY, & CONDUIT									
			RACEWAY, CABLE TRAY, & CONDUIT -		396.00 TN	40	65.69 /MH	2,601		-	-	2,601
			RACEWAY, CABLE TRAY, & CONDUIT			40		2,601				2,601
		10.86.00	WASTE									
			WASTE - OIL CONTAMINATED FILL	ASSUMED 5 FEET DEEP IS CONTAMINATED	9,204.00 CY	10,916	168.91 /MH	1,843,812	0	-	-	1,843,812
			WASTE - METAL CLEANING TANK BERMED AREA CONTAMINATED FILL	ASSUMED 5 FEET DEEP IS CONTAMINATED	3,703.00 CY	4,392	168.91 /MH	741,812	0	-	-	741,812
			WASTE - BUILDING WASTE - COMMON BLDGS		3,636.00 CY	364	65.69 /MH	23,885	36,360	-	-	60,245
			WASTE			15,671		2,609,509	36,360			2,645,869
			WHOLE PLANT DEMOLITION			211,270		19,483,672	11,020,976	4,400,000		34,904,648
	18.00.00		SCRAP VALUE									
		18.10.00	MIXED STEEL									

Area	Group	Phase	Description	Notes	Quantity	Man Hours	Crew Rate	Labor Cost	Material Cost	Subcontract Cost	Process Equipment Cost	Total Cost
		18.10.00	**MIXED STEEL**									
			MIXED STEEL, DEWATERING HYDOCLONE FEED TANK A, 850,800 GALLON		-123.00 TN		65.97 /MH		-	-	(35,301)	(35,301)
			MIXED STEEL, DEWATERING HYDOCLONE FEED TANK B, 850,800 GALLON		-123.00 TN		65.97 /MH		-	-	(35,301)	(35,301)
			MIXED STEEL, RECLAIM WATER TANK A, 351,000 GALLONS		-60.00 TN		65.97 /MH		-	-	(17,220)	(17,220)
			MIXED STEEL, RECLAIM WATER TANK B, 351,000 GALLONS		-60.00 TN		65.97 /MH		-	-	(17,220)	(17,220)
			MIXED STEEL, REAGENT SLURRY STORAGE TANK A, 457,920 GALLONS		-64.00 TN		65.97 /MH		-	-	(18,368)	(18,368)
			MIXED STEEL, REAGENT SLURRY STORAGE TANK B, 457,920 GALLONS		-64.00 TN		65.97 /MH		-	-	(18,368)	(18,368)
			MIXED STEEL, MAINTENANCE STORAGE TANK, 1,417,000 GALLONS		-129.00 TN		65.97 /MH		-	-	(37,023)	(37,023)
			MIXED STEEL, FGD SERVICE WATER TANK, 399,480 GALLONS		-37.00 TN		65.97 /MH		-	-	(10,619)	(10,619)
			MIXED STEEL, UREA FEED TANK, 200,000 GALLONS		-25.00 TN		65.97 /MH		-	-	(7,175)	(7,175)
			MIXED STEEL, FUEL OIL STORAGE TANK, 500,000 GALLONS		-50.00 TN		65.97 /MH		-	-	(14,350)	(14,350)
			MIXED STEEL, FUEL OIL STORAGE TANK, 1,500,000 GALLONS		-131.00 TN		65.97 /MH		-	-	(37,597)	(37,597)
			MIXED STEEL, METAL CLEANING WASTE TREATMENT TANK, 1,000,000 GALLONS		-83.00 TN		65.97 /MH		-	-	(23,821)	(23,821)
			MIXED STEEL, FGD BLDG FRAMING & GIRTS		-1,050.00 TN		65.97 /MH		-	-	(301,350)	(301,350)
			MIXED STEEL, DEWATERING AREA BLDG FRAMING & GIRTS		-400.00 TN		65.97 /MH		-	-	(114,800)	(114,800)
			MIXED STEEL, REAGENT PREP AREA FRAMING & GIRTS		-414.00 TN		65.97 /MH		-	-	(118,818)	(118,818)
			MIXED STEEL, SERVICE BLDG FRAMING & GIRTS		-520.00 TN		65.97 /MH		-	-	(149,240)	(149,240)
			MIXED STEEL REBAR RECOVERY FROM OUTBUILDINGS FOUNDATIONS & MISC FDNS		-363.00 TN		65.97 /MH		-	-	(104,181)	(104,181)
			MIXED STEEL REBAR RECOVERY FROM 1200' CHIMNEY		-680.00 TN		65.97 /MH		-	-	(195,160)	(195,160)
			MIXED STEEL, STEEL LINER FROM 1200' CHIMNEY		-1,005.00 TN		65.97 /MH		-	-	(288,435)	(288,435)
			MIXED STEEL, EQUIPMENT FOUNDATION110 LB/CY, MISC EQUIPMENT, REINFORCING		-72.00 TN		65.97 /MH		-	-	(20,664)	(20,664)
			MIXED STEEL REBAR RECOVERY FROM 1000' CHIMNEY		-730.00 TN		65.97 /MH		-	-	(209,510)	(209,510)
			MIXED STEEL, MECHANICAL EQUIPMENT - FGD EQUIPMENT		-646.00 TN		65.97 /MH		-	-	(185,402)	(185,402)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - LIMESTONE/GYPSUM GYPSUM CLAMSHELL UNLOADER		-400.00 TN		65.97 /MH		-	-	(114,800)	(114,800)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - LIMESTONE//GYPSUM BUCKET BARGE UNLOADER		-400.00 TN		65.97 /MH		-	-	(114,800)	(114,800)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - COAL BUCKET BARGE UNLOADER		-400.00 TN		65.97 /MH		-	-	(114,800)	(114,800)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - GYPSUM HANDLING SYSTEM		-728.00 TN		65.97 /MH		-	-	(208,936)	(208,936)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - LIMESTONE HANDLING SYSTEM		-2,158.00 TN		65.97 /MH		-	-	(619,346)	(619,346)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - COAL HANDLING SYSTEM, COMMON		-3,244.00 TN		65.97 /MH		-	-	(931,028)	(931,028)
			MIXED STEEL, MECHANICAL EQUIPMENT - DRY SORBENT SYSTEM		-100.00 TN		65.97 /MH		-	-	(28,700)	(28,700)
			MIXED STEEL, 228000 TF OF RAILROAD TRACK		-8,388.00 TN		65.97 /MH		-	-	(2,407,356)	(2,407,356)
			MIXED STEEL, DEMOLITION - PULL SHEET PILE & CAP FOR BARGE CELLS		-654.00 TN		65.97 /MH		-	-	(187,698)	(187,698)
			MIXED STEEL, RACEWAY, CABLE TRAY, & CONDUIT -		-396.00 TN		65.97 /MH		-	-	(113,652)	(113,652)
			MIXED STEEL, MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS		-222.60 TN		65.97 /MH		-	-	(63,886)	(63,886)
			MIXED STEEL								**(6,864,925)**	**(6,864,925)**
		18.30.00	**COPPER**									
			COPPER SCRAP CABLE & COMMON		-200.00 TN		65.97 /MH		-	-	(1,218,200)	(1,218,200)
			COPPER, MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS		-92.00 TN		65.97 /MH		-	-	(560,372)	(560,372)
			COPPER								**(1,778,572)**	**(1,778,572)**

Area	Group	Phase	Description	Notes	Quantity	Man Hours	Crew Rate	Labor Cost	Material Cost	Subcontract Cost	Process Equipment Cost	Total Cost
			SCRAP VALUE								**(8,643,497)**	**(8,643,497)**
			Common			**211,270**		**19,483,672**	**11,020,976**	**4,400,000**	**(8,643,497)**	**26,261,150**
Unit 1												
	10.00.00		**WHOLE PLANT DEMOLITION**									
		10.22.00	**CONCRETE**									
			BUILDING PAD FOUNDATION 110 LB/CY, UNIT 1 COOLING TOWER BASIN		8,840.00 CY	9,945	75.99 /MH	755,721		-	-	755,721
			ELEVATED FOUNDATION 110/CY, UNIT 1 COOLING TOWER SHELL		9,200.00 CY	5,511	75.99 /MH	418,766		-	-	418,766
			ELEVATED FOUNDATION, UNIT 1 TURBINE AND BLR BLDGS		2,000.00 CY	1,198	75.99 /MH	91,036		-	-	91,036
			TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 1		7,778.00 CY	14,000	75.99 /MH	1,063,890		-	-	1,063,890
			CONCRETE			**30,654**		**2,329,413**				**2,329,413**
		10.23.00	**STEEL**									
			DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 1		1,922.00 TN	5,136	65.97 /MH	338,794		-	-	338,794
			STEEL			**5,136**		**338,794**				**338,794**
		10.24.00	**ARCHITECTURAL**									
			BUILDING, UNIT 1 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS		8,500,000.00 CF	85,000	75.09 /MH	6,382,650		-	-	6,382,650
			ARCHITECTURAL			**85,000**		**6,382,650**				**6,382,650**
		10.31.00	**MECHANICAL EQUIPMENT**									
			MAIN BOILER AND APPURTENANCES, UNIT 1		12,160.00 TN	24,624	71.44 /MH	1,759,139		-	-	1,759,139
			FD & ID FANS, UNIT 1		6,135.00 TN	12,423	71.44 /MH	887,526		-	-	887,526
			FEEDWATER DEARATING EQUIPMENT, UNIT 1		215.00 TN	435	65.69 /MH	28,600		-	-	28,600
			TANK, UNIT 1 CLEAN CONDENSATE TANK, 753,000 GALLONS	60' DIA X 40' HIGH	77.00 TN	206	65.69 /MH	13,515		-	-	13,515
			TANK, UNIT 1 CONTAMINATED CONDENSATE TANK, 500,000 GALLONS	50' DIA X 35' HIGH	50.00 TN	134	65.69 /MH	8,776		-	-	8,776
			TANK, UNIT 1 EQUALIZATION TANK. 220,600 GALLONS	38' DIA X 30' HIGH	30.00 TN	80	65.69 /MH	5,266		-	-	5,266
			TANK, UNIT 1 ABSORBER REACTION TANK		462.00 TN	1,234	65.69 /MH	81,092		-	-	81,092
			WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 1		269.00 TN	545	65.69 /MH	35,783		-	-	35,783
			TURBINE GENERATOR, UNIT 1		2,045.00 TN	4,141	65.69 /MH	272,031		-	-	272,031
			CONDENSER, UNIT 1		1,165.00 TN	2,359	65.69 /MH	154,971		-	-	154,971
			CIRCULATING WATER EQUIPMENT, UNIT 1		484.00 TN	980	65.69 /MH	64,383		-	-	64,383
			COOLING TOWER, UNIT 1 REMOVE FILL		690,000.00 CF	4,140	65.69 /MH	271,957		-	-	271,957
			MECHANICAL EQUIPMENT - UNIT 1 MISC. POWER PLANT EQUIPMENT		613.00 TN	1,241	65.69 /MH	81,543		-	-	81,543
			MECHANICAL EQUIPMENT - DEMOLISH UNIT 1 TURBINE ROOM OVERHEAD CRANE		1.00 LS	315	65.69 /MH	20,692		-	-	20,692
			MECHANICAL EQUIPMENT - UNIT 1 DUST COLLECTORS		269.00 TN	545	65.69 /MH	35,783		-	-	35,783
			MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 1		1,000.00 TN	2,025	65.69 /MH	133,022		-	-	133,022
			MECHANICAL EQUIPMENT - SCR UNIT 1		664.00 TN	1,345	65.69 /MH	88,327		-	-	88,327
			MECHANICAL EQUIPMENT			**56,772**		**3,942,404**				**3,942,404**
		10.33.00	**MATERIAL HANDLING EQUIPMENT**									
			MATERIAL HANDLING EQUIPMENT - UNIT 1 ASH HANDLING EQUIPMENT		377.00 TN	763	65.69 /MH	50,149		-	-	50,149
			MATERIAL HANDLING EQUIPMENT - UNIT 1 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS		1,432.00 TN	2,900	65.69 /MH	190,488		-	-	190,488
			MATERIAL HANDLING EQUIPMENT			**3,663**		**240,637**				**240,637**
		10.34.00	**HVAC**									
			HVAC - UNIT 1		1.00 LS	1,695	65.69 /MH	111,345		-	-	111,345
			HVAC			**1,695**		**111,345**				**111,345**
		10.35.00	**PIPING**									
			PIPING - UNIT 1 BOILER PLANT AND TURBINE PIPING		2,690.00 TN	5,719	65.69 /MH	375,677		-	-	375,677

Area	Group	Phase	Description	Notes	Quantity	Man Hours	Crew Rate	Labor Cost	Material Cost	Subcontract Cost	Process Equipment Cost	Total Cost
			PIPING			**5,719**		**375,677**				**375,677**
		10.41.00	**ELECTRICAL EQUIPMENT**									
			GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER		328.00 TN	876	65.69 /MH	57,572		-	-	57,572
			STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS		109.00 TN	291	65.69 /MH	19,132		-	-	19,132
			ELECTRICAL EQUIPMENT			**1,168**		**76,704**				**76,704**
		10.86.00	**WASTE**									
			WASTE - UNIT 1 COOLING TOWER FILL	FIBERGLASS AND WOOD	2,555.00 CY	256	65.69 /MH	16,784	25,550	-	-	42,334
			WASTE - USER DEFINED - UNIT 1 BLDG WASTE		3,200.00 CY	320	65.69 /MH	21,021	32,000	-	-	53,021
			WASTE			**576**		**37,805**	**57,550**			**95,355**
			WHOLE PLANT DEMOLITION			**190,383**		**13,835,429**	**57,550**			**13,892,979**
	18.00.00		**SCRAP VALUE**									
		18.10.00	**MIXED STEEL**									
			MIXED STEEL, UNIT 1 CLEAN CONDENSATE TANK, 753,000 GALLONS		-77.00 TN		65.97 /MH		-	-	(22,099)	(22,099)
			MIXED STEEL, UNIT 1 CONTAMINATED CONDENSATE TANK, 500,000 GALLONS		-50.00 TN		65.97 /MH		-	-	(14,350)	(14,350)
			MIXED STEEL, UNIT 1 EQUALIZATION TANK. 220,600 GALLONS		-30.00 TN		65.97 /MH		-	-	(8,610)	(8,610)
			MIXED STEEL, UNIT 1 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS		-4,250.00 TN		65.97 /MH		-	-	(1,219,750)	(1,219,750)
			MIXED STEEL, REBAR RECOVERED, TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 1		-467.00 TN		65.97 /MH		-	-	(134,029)	(134,029)
			MIXED STEEL, UNIT 1 COOLING TOWER REINFORCING RECOVERED		-440.00 TN		65.97 /MH		-	-	(126,280)	(126,280)
			MIXED STEEL, ELEVATED FOUNDATION, UNIT 1 TURBINE AND BLR BLDGS, REINFORCING		-110.00 TN		65.97 /MH		-	-	(31,570)	(31,570)
			MIXED STEEL, MAIN BOILER AND APPURTENANCES, UNIT 1		-12,160.00 TN		65.97 /MH		-	-	(3,489,920)	(3,489,920)
			MIXED STEEL, FD & ID FANS, UNIT 1		-6,135.00 TN		65.97 /MH		-	-	(1,760,745)	(1,760,745)
			MIXED STEEL, DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 1		-1,922.00 TN		65.97 /MH		-	-	(551,614)	(551,614)
			MIXED STEEL, FEEDWATER DEARATING EQUIPMENT, UNIT 1		-215.00 TN		65.97 /MH		-	-	(61,705)	(61,705)
			MIXED STEEL, WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 1		-269.00 TN		65.97 /MH		-	-	(77,203)	(77,203)
			MIXED STEEL, UNIT 1 CONDENSER		-792.00 TN		65.97 /MH		-	-	(227,304)	(227,304)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 1 ASH HANDLING EQUIPMENT		-377.00 TN		65.97 /MH		-	-	(108,199)	(108,199)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 1 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS		-1,432.00 TN		65.97 /MH		-	-	(410,984)	(410,984)
			MIXED STEEL, TURBINE GENERATOR, UNIT 1		-2,045.00 TN		65.97 /MH		-	-	(586,915)	(586,915)
			MIXED STEEL, CIRCULATING WATER EQUIPMENT, UNIT 1		-484.00 TN		65.97 /MH		-	-	(138,908)	(138,908)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 1 MISC. POWER PLANT EQUIPMENT		-613.00 TN		65.97 /MH		-	-	(175,931)	(175,931)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 1 DUST COLLECTORS		-269.00 TN		65.97 /MH		-	-	(77,203)	(77,203)
			MIXED STEEL, PIPING - UNIT 1 BOILER PLANT AND TURBINE PIPING		-2,690.00 TN		65.97 /MH		-	-	(772,030)	(772,030)
			MIXED STEEL, MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 1		-1,000.00 TN		65.97 /MH		-	-	(287,000)	(287,000)
			MIXED STEEL, GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER		-180.50 TN		65.97 /MH		-	-	(51,804)	(51,804)
			MIXED STEEL, STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS		-56.00 TN		65.97 /MH		-	-	(16,072)	(16,072)
			MIXED STEEL, MECHANICAL EQUIPMENT - SCR UNIT 1		-664.00 TN		65.97 /MH		-	-	(190,568)	(190,568)
			MIXED STEEL								**(10,540,793)**	**(10,540,793)**
		18.20.00	**STAINLESS STEEL**									

Area	Group	Phase	Description	Notes	Quantity	Man Hours	Crew Rate	Labor Cost	Material Cost	Subcontract Cost	Process Equipment Cost	Total Cost
		18.20.00	**STAINLESS STEEL**									
			STAINLESS STEEL, TANK, UNIT 1 ABSORBER REACTION TANK		-462.00 TN		65.97 /MH		-	-	(645,414)	(645,414)
			STAINLESS STEEL								**(645,414)**	**(645,414)**
		18.30.00	**COPPER**									
			COPPER, UNIT 1 CONDENSER CU / NI TUBES		-373.00 TN		65.97 /MH		-	-	(2,271,943)	(2,271,943)
			COPPER, GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER		-200.00 TN		65.97 /MH		-	-	(1,218,200)	(1,218,200)
			COPPER, STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS		-53.00 TN		65.97 /MH		-	-	(322,823)	(322,823)
			COPPER								**(3,812,966)**	**(3,812,966)**
			SCRAP VALUE								**(14,999,173)**	**(14,999,173)**
			Unit 1			**190,383**		**13,835,429**	**57,550**		**(14,999,173)**	**(1,106,194)**
Unit 2												
	10.00.00		**WHOLE PLANT DEMOLITION**									
		10.22.00	**CONCRETE**									
			BUILDING PAD FOUNDATION 110 LB/CY, UNIT 2 COOLING TOWER BASIN		8,840.00 CY	9,945	75.99 /MH	755,721		-	-	755,721
			ELEVATED FOUNDATION 110/CY, UNIT 2 COOLING TOWER SHELL		9,200.00 CY	5,511	75.99 /MH	418,766		-	-	418,766
			ELEVATED FOUNDATION , UNIT 2 TURBINE AND BLR BLDGS		2,000.00 CY	1,198	75.99 /MH	91,036		-	-	91,036
			TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 2		7,778.00 CY	14,000	75.99 /MH	1,063,890		-	-	1,063,890
			CONCRETE			**30,654**		**2,329,413**				**2,329,413**
		10.23.00	**STEEL**									
			DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 2		1,022.00 TN	2,731	65.97 /MH	180,150		-	-	180,150
			STEEL			**2,731**		**180,150**				**180,150**
		10.24.00	**ARCHITECTURAL**									
			BUILDING, UNIT 2 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS		8,500,000.00 CF	85,000	75.09 /MH	6,382,650		-	-	6,382,650
			ARCHITECTURAL			**85,000**		**6,382,650**				**6,382,650**
		10.31.00	**MECHANICAL EQUIPMENT**									
			MAIN BOILER AND APPURTENANCES, UNIT 2		12,160.00 TN	24,624	71.44 /MH	1,759,139		-	-	1,759,139
			FD & ID FANS, UNIT 2		6,135.00 TN	12,423	71.44 /MH	887,526		-	-	887,526
			FEEDWATER DEARATING EQUIPMENT, UNIT 2		215.00 TN	435	65.69 /MH	28,600		-	-	28,600
			TANK, UNIT 2 CLEAN CONDENSATE TANK, 753,000 GALLONS	60' DIA X 40' HIGH	77.00 TN	206	65.69 /MH	13,515		-	-	13,515
			TANK, UNIT 2 CONTAMINATED CONDENSATE TANK, 500,000 GALLONS	50' DIA X 35' HIGH	50.00 TN	134	65.69 /MH	8,776		-	-	8,776
			TANK, UNIT 2 EQUALIZATION TANK. 220,600 GALLONS	38' DIA X 30' HIGH	30.00 TN	80	65.69 /MH	5,266		-	-	5,266
			TANK, UNIT 2 ABSORBER REACTION TANK		462.00 TN	1,234	65.69 /MH	81,092		-	-	81,092
			WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 2		269.00 TN	545	65.69 /MH	35,783		-	-	35,783
			TURBINE GENERATOR, UNIT 2		2,045.00 TN	4,141	65.69 /MH	272,031		-	-	272,031
			CONDENSER, UNIT 2		1,165.00 TN	2,359	65.69 /MH	154,971		-	-	154,971
			CIRCULATING WATER EQUIPMENT, UNIT 2		484.00 TN	980	65.69 /MH	64,383		-	-	64,383
			COOLING TOWER, UNIT 2 REMOVE FILL		690,000.00 CF	4,140	65.69 /MH	271,957		-	-	271,957
			MECHANICAL EQUIPMENT - UNIT 2 MISC. POWER PLANT EQUIPMENT		613.00 TN	1,241	65.69 /MH	81,543		-	-	81,543
			MECHANICAL EQUIPMENT - DEMOLISH UNIT 2 TURBINE ROOM OVERHEAD CRANE		1.00 LS	315	65.69 /MH	20,692		-	-	20,692
			MECHANICAL EQUIPMENT - UNIT 2 DUST COLLECTORS		269.00 TN	545	65.69 /MH	35,783		-	-	35,783
			MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 2		1,000.00 TN	2,025	65.69 /MH	133,022		-	-	133,022
			MECHANICAL EQUIPMENT - SCR UNIT 2		664.00 TN	1,345	65.69 /MH	88,327		-	-	88,327
			MECHANICAL EQUIPMENT			**56,772**		**3,942,404**				**3,942,404**

Area	Group	Phase	Description	Notes	Quantity	Man Hours	Crew Rate	Labor Cost	Material Cost	Subcontract Cost	Process Equipment Cost	Total Cost
		10.33.00	**MATERIAL HANDLING EQUIPMENT**									
			MATERIAL HANDLING EQUIPMENT - UNIT 2 ASH HANDLING EQUIPMENT		377.00 TN	763	65.69 /MH	50,149		-	-	50,149
			MATERIAL HANDLING EQUIPMENT - UNIT 2 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS		1,432.00 TN	2,900	65.69 /MH	190,488		-	-	190,488
			MATERIAL HANDLING EQUIPMENT			**3,663**		**240,637**				**240,637**
		10.34.00	**HVAC**									
			HVAC - UNIT 2		1.00 LS	1,695	65.69 /MH	111,345		-	-	111,345
			HVAC			**1,695**		**111,345**				**111,345**
		10.35.00	**PIPING**									
			PIPING - UNIT 2 BOILER PLANT AND TURBINE PIPING		2,690.00 TN	5,719	65.69 /MH	375,677		-	-	375,677
			PIPING			**5,719**		**375,677**				**375,677**
		10.41.00	**ELECTRICAL EQUIPMENT**									
			GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMER		328.00 TN	876	65.69 /MH	57,572		-	-	57,572
			STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS		109.00 TN	291	65.69 /MH	19,132		-	-	19,132
			ELECTRICAL EQUIPMENT			**1,168**		**76,704**				**76,704**
		10.86.00	**WASTE**									
			WASTE - UNIT 2 COOLING TOWER FILL	FIBERGLASS AND WOOD	2,555.00 CY	256	65.69 /MH	16,784	25,550	-	-	42,334
			WASTE - USER DEFINED - UNIT 2 BLDG WASTE		3,200.00 CY	320	65.69 /MH	21,021	32,000	-	-	53,021
			WASTE			**576**		**37,805**	**57,550**			**95,355**
			WHOLE PLANT DEMOLITION			**187,978**		**13,676,784**	**57,550**			**13,734,334**
	18.00.00		**SCRAP VALUE**									
		18.10.00	**MIXED STEEL**									
			MIXED STEEL, UNIT 2 CLEAN CONDENSATE TANK, 753,000 GALLONS		-77.00 TN		65.97 /MH		-	-	(22,099)	(22,099)
			MIXED STEEL, UNIT 2 CONTAMINATED CONDENSATE TANK, 500,000 GALLONS		-50.00 TN		65.97 /MH		-	-	(14,350)	(14,350)
			MIXED STEEL, UNIT 2 EQUALIZATION TANK. 220,600 GALLONS		-30.00 TN		65.97 /MH		-	-	(8,610)	(8,610)
			MIXED STEEL, UNIT 2 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS		-4,250.00 TN		65.97 /MH		-	-	(1,219,750)	(1,219,750)
			MIXED STEEL, REBAR RECOVERED, TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 2		-467.00 TN		65.97 /MH		-	-	(134,029)	(134,029)
			MIXED STEEL, UNIT 2 COOLING TOWER REINFORCING RECOVERED		-440.00 TN		65.97 /MH		-	-	(126,280)	(126,280)
			MIXED STEEL, ELEVATED FOUNDATION , UNIT 2 TURBINE AND BLR BLDGS, REINFORCING		-110.00 TN		65.97 /MH		-	-	(31,570)	(31,570)
			MIXED STEEL, MAIN BOILER AND APPURTENANCES, UNIT 2		-12,160.00 TN		65.97 /MH		-	-	(3,489,920)	(3,489,920)
			MIXED STEEL, FD & ID FANS, UNIT 2		-6,135.00 TN		65.97 /MH		-	-	(1,760,745)	(1,760,745)
			MIXED STEEL, DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 2		-1,022.00 TN		65.97 /MH		-	-	(293,314)	(293,314)
			MIXED STEEL, FEEDWATER DEARATING EQUIPMENT, UNIT 2		-215.00 TN		65.97 /MH		-	-	(61,705)	(61,705)
			MIXED STEEL, WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 2		-269.00 TN		65.97 /MH		-	-	(77,203)	(77,203)
			MIXED STEEL, UNIT 2 CONDENSER		-792.00 TN		65.97 /MH		-	-	(227,304)	(227,304)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 2 ASH HANDLING EQUIPMENT		-377.00 TN		65.97 /MH		-	-	(108,199)	(108,199)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 2 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS		-1,432.00 TN		65.97 /MH		-	-	(410,984)	(410,984)
			MIXED STEEL, TURBINE GENERATOR, UNIT 2		-2,045.00 TN		65.97 /MH		-	-	(586,915)	(586,915)
			MIXED STEEL, CIRCULATING WATER EQUIPMENT, UNIT 2		-484.00 TN		65.97 /MH		-	-	(138,908)	(138,908)

Area	Group	Phase	Description	Notes	Quantity	Man Hours	Crew Rate	Labor Cost	Material Cost	Subcontract Cost	Process Equipment Cost	Total Cost
		18.10.00	**MIXED STEEL**									
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 2 MISC. POWER PLANT EQUIPMENT		-613.00 TN		65.97 /MH		-	-	(175,931)	(175,931)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 2 DUST COLLECTORS		-269.00 TN		65.97 /MH		-	-	(77,203)	(77,203)
			MIXED STEEL, PIPING - UNIT 2 BOILER PLANT AND TURBINE PIPING		-2,690.00 TN		65.97 /MH		-	-	(772,030)	(772,030)
			MIXED STEEL, MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 2		-1,000.00 TN		65.97 /MH		-	-	(287,000)	(287,000)
			MIXED STEEL, GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMERS		-180.50 TN		65.97 /MH		-	-	(51,804)	(51,804)
			MIXED STEEL, STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS		-56.00 TN		65.97 /MH		-	-	(16,072)	(16,072)
			MIXED STEEL, MECHANICAL EQUIPMENT - SCR UNIT 2		-664.00 TN		65.97 /MH		-	-	(190,568)	(190,568)
			MIXED STEEL								**(10,282,493)**	**(10,282,493)**
		18.20.00	**STAINLESS STEEL**									
			STAINLESS STEEL, TANK, UNIT 2 ABSORBER REACTION TANK		-462.00 TN		65.97 /MH		-	-	(645,414)	(645,414)
			STAINLESS STEEL								**(645,414)**	**(645,414)**
		18.30.00	**COPPER**									
			COPPER, UNIT 2 CONDENSER CU / NI TUBES		-373.00 TN		65.97 /MH		-	-	(2,271,943)	(2,271,943)
			COPPER, GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMER		-147.50 TN		65.97 /MH		-	-	(898,423)	(898,423)
			COPPER, STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS		-53.00 TN		65.97 /MH		-	-	(322,823)	(322,823)
			COPPER								**(3,493,189)**	**(3,493,189)**
			SCRAP VALUE								**(14,421,095)**	**(14,421,095)**
			Unit 2			**187,978**		**13,676,784**	**57,550**		**(14,421,095)**	**(686,761)**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)	**Case No. 2014-00396**

DIRECT TESTIMONY OF

AMY J. ELLIOTT

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

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

Amy J. Elliott

Amy J. Elliott

COMMONWEALTH OF KENTUCKY	)	
	)	Case No. 2014-00396
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Amy J. Elliott, this 16th day of December, 2014.

Tracy K Rasquist 481393

Notary Public

My Commission Expires: January 23, 2017

DIRECT TESTIMONY OF
AMY J. ELLIOTT, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
AMY J. ELLIOTT, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Amy J. Elliott. I am a Regulatory Consultant for Kentucky Power Company ("Kentucky Power" or the "Company") and my business address is 101 A Enterprise Drive, Frankfort, Kentucky 40601.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. In 2000, I received a Bachelor of Arts degree in Economics from Transylvania University in Lexington, Kentucky. I worked for the Tennessee Department of Commerce and Insurance as an Insurance Examiner from early 2002 through late 2005 before moving back to Kentucky and consulting with insurance companies in connection with field audits. I accepted my present position with Kentucky Power in 2008. In 2012, I received a Master of Business Administration degree from the University of Massachusetts at Amherst.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH KPCO?

A. In addition to general regulatory duties, I am responsible for compiling the monthly Environmental Surcharge and Fuel Adjustment Clause ("FAC") reports.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

Yes, I testified before the Kentucky Public Service Commission in two six-month reviews of the Company's FAC, Case No. 2013-00261 and Case No. 2013-00444. I also submitted pre-filed testimony in two six-month reviews of the Company's Environmental Surcharge, Case No. 2014-00052 and Case No. 2014-00322.

III. PURPOSE OF YOUR TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony in this proceeding is to support the Company's Application for Approval of its Fourth Amended Environmental Compliance Plan ("2014 Plan" or "Plan"). In particular, my testimony covers the following topics:

- Changes to the Company's Environmental Compliance Plan included in the proposed Fourth Amendment;
- The Calculation of the Company's monthly environmental base requirement;
- Changes to the Company's Tariff E.S.; and
- Recovery of costs associated with the Mitchell flue gas desulfurization ("FGD") system.

Q. **PLEASE IDENTIFY THE OTHER WITNESSES WHOSE TESTIMONY SUPPORTS KENTUCKY POWER'S ENVIRONMENTAL COMPLIANCE PLAN.**

A.

Witness	Title	Testimony Support
William E. Avera Adrien M. McKenzie	Financial Concepts and Applications Consultants	Cost of Equity
Jeffrey B. Bartsch	Director, Tax Accounting & Regulatory Support	Tax Consequences
David A. Davis	Manager, Property Accounting Policy and Research	Depreciation Calculation
Jeffrey D. LaFleur	Vice President, Generating Assets	Project Descriptions and Cost Estimates
John M. McManus	Vice President, Environmental Services	Environmental Laws and Regulations

Q. PLEASE LIST THE EXHIBITS TO YOUR TESTIMONY THAT YOU PREPARED:

A. I prepared the following exhibits to my testimony:

- AJE-1 - 2014 Environmental Compliance Plan
- AJE-2 - Environmental Surcharge Tariff (Tariff E.S.) showing changes from the current tariff
- AJE-3 - Total Base Revenue Requirement Summary
- AJE-4 - Estimated Mitchell FGD annual revenue requirement
- AJE-5 - Mitchell Gross Revenue Conversion Factor

IV. KENTUCKY POWER'S FOURTH AMENDED ENVIRONMENTAL COMPLIANCE PLAN

Q. PLEASE EXPLAIN WHY THE COMPANY IS UPDATING ITS ENVIRONMENTAL COMPLIANCE PLAN.

A. The Company's current Environmental Compliance Plan is the 2007 Plan. The Company is proposing to update its current Environmental Compliance Plan with the 2014 Plan to reflect changes in the Company's environmental projects. The Company's environmental projects are those necessary to comply with the Federal Clean Air Act as amended and or other federal, state, or local environmental requirements which apply to coal combustion wastes ("Environmental Requirements"). The proposed 2014 Plan, attached as Exhibit AJE-1, reflects changes since the filing of the 2007 Plan in the Company's generation portfolio. These changes include:

- The December 31, 2013 transfer to Kentucky Power of an undivided 50% interest in the Mitchell Plant, including environmental projects not included in the company's current Environmental Compliance Plan, located in Moundsville, West Virginia (the "Mitchell Transfer");
- The planned retirement of Big Sandy Unit 2 no later than June 1, 2015;

- The planned conversion of Big Sandy Unit 1 to natural gas by June 30, 2016;
- The January 1, 2014 termination of the AEP East-System Pool;
- The addition of environmental projects at the Mitchell and Rockport Plants; and
- Planned environmental projects at the Rockport Plant.

Q. HAS THE COMPANY REVISED ITS ENVIRONMENTAL SURCHARGE TARIFF TO REFLECT THE CHANGES PROPOSED IN THIS PLAN?

A. Yes. Please see Exhibit AJE-2. The changes to Tariff E.S. are described in more detail later in my testimony.

<u>Previously-Approved Projects Being Removed From 2014 Plan</u>

Q. IS THE COMPANY PROPOSING TO REMOVE ANY PREVIOUSLY-APPROVED ENVIRONMENTAL PROJECTS IN ITS 2014 PLAN?

A. Yes. The Company is proposing to remove the following categories of environmental projects from its Environmental Compliance Plan:

- Environmental Projects previously included as a result of Kentucky Power's participation in the AEP East-System Pool; and
- Environmental Projects at the Big Sandy Plant, with the exception of Big Sandy Title IV, CSAPR and NO_X allowances.

Q. WHY IS THE COMPANY REMOVING THE POOL-RELATED ENVIRONMENTAL PROJECTS?

A. As mentioned above, the AEP East-System Pool terminated effective January 1, 2014. With the termination, Kentucky Power no longer incurs costs for pool-related environmental projects and likewise does not include pool-related environmental costs in its environmental surcharge filings.

Q. WHY DID THE COMPANY REMOVE THE BIG SANDY PROJECTS FROM THE 2014 PLAN?

A. First, to comply with the requirements of the Mercury and Air Toxics Standards ("MATS") Rule, Kentucky Power will retire Big Sandy Unit 2 no later than June 1, 2015. Second, Kentucky is proposing the Big Sandy 1 Operation Rider ("BS1OR") which would serve to recover all of the operations and maintenance expenses for Big Sandy 1, including those costs which would otherwise be recoverable through the environmental surcharge. The BS1OR is described in more detail in the testimony of Company Witness Wohnhas. Because the Company is proposing to recover all of Big Sandy Unit 1 expenses through the BS1OR and because Big Sandy Unit 2 will retire, the Company is removing the Big Sandy Environmental projects from its Environmental Compliance Plan.

Q. WHAT PREVIOUSLY APPROVED ENVIRONMENTAL PROJECTS WILL REMAIN IN THE COMPANY'S ENVIRONMENTAL PLAN AFTER THE POOL AND BIG SANDY RELATED PROJECTS ARE REMOVED?

A. The 2014 Environmental Compliance Plan removes all but the following currently included environmental projects from Kentucky Power's Environmental Compliance Plan:

- Mitchell Units 1 and 2 Water Injection, Low NO_X Burners, Low NO_X Burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation;
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities;
- Continuous Emission Monitors (CEMS) - Rockport Plant;
- Rockport Units 1 and 2 Low NOX Burners, Over Fire Air, and Landfill;
- Title V Air Emission Fees at Mitchell and Rockport Plants;
- Costs associated with NO_x Allowances; and

- Costs associated with SO_2 Allowances.

Q. IF IT WERE NOT PROPOSING BOTH THE BSRR AND THE BS1OR, WOULD THE COMPANY BE PROPOSING TO REMOVE THE BIG SANDY ENVIRONMENTAL COMPLIANCE PROJECTS FROM ITS PLAN?

A. No. The Company is proposing to recover the operational costs associated with the currently approved environmental projects at Big Sandy Unit 1 as part of the costs recovered through the BS1OR. The remaining environmental capital investment for environmental projects associated with Big Sandy Unit 1 will be included as part of those costs recovered through the BSRR. If the Company were not proposing these riders, the Big Sandy Unit 1 environmental projects would remain in the Company's Environmental Compliance Plan, and all costs associated with those projects would flow through the environmental surcharge.

Q. WHY DID THE COMPANY KEEP THE BIG SANDY EMISSION ALLOWANCES IN THE 2014 PLAN?

A. The Company retained the emissions allowances for Big Sandy in the proposed 2014 Plan for two reasons. First, the Company records allowances on a per-Company basis allowing it to utilize allowances at other Kentucky Power plants. Second, keeping the Big Sandy emission allowances in the Environmental Compliance Plan allows for any potential gains on those allowances to flow through the environmental surcharge to the customers.

<u>Mitchell Environmental Projects</u>

Q. PLEASE LIST THE MITCHELL PLANT'S ENVIRONMENTAL PROJECTS THAT THE COMPANY PROPOSES TO ADD IN ITS 2014 COMPLIANCE PLAN.

A. Kentucky Power proposes to add the following Mitchell Plant environmental projects through the 2014 Plan :

- Precipitator Modifications - Mitchell Plant Units 1 and 2;
- Bottom Ash and Fly Ash Handling - Mitchell Plant Units 1 and 2;
- Mercury Monitoring (MATS) - Mitchell Plant Units 1 and 2;
- Dry Fly Ash Handling Conversion - Mitchell Plant Units 1 and 2;
- Coal Combustion Waste Landfill - Mitchell Plant Units 1 and 2; and
- Electrostatic Precipitator Upgrade - Mitchell Plant Unit 2.

Q. PLEASE LIST THE MITCHELL ENVIRONMENTAL PROJECTS INCLUDED IN THE 2014 PLAN WHICH ARE NOT CURRENTLY IN SERVICE.

A. Two of the Mitchell environmental projects in the 2014 Plan are not fully in service. The next phase of the Coal Combustion Waste Landfill will not be in service until 2015. Similarly, the Electrostatic Precipitator Upgrade for Unit 2 will not be in service until 2015.

Q. OF THE MITCHELL PLANT ENVIRONMENTAL PROJECTS, WHICH HAVE BEEN PLACED IN SERVICE SINCE THE DATE OF THE MITCHELL TRANSFER?

A. Since the Mitchell Transfer occurred on December 31, 2013, the following environmental projects have been placed in service at the Mitchell Plant:

- Mercury Monitoring (MATS);
- Dry Fly Ash Handling Conversion; and
- The initial phase of the Coal Combustion Waste Landfill.

Q. DID KENTUCKY POWER OBTAIN A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (“CPCN”) PRIOR TO COMMENCING CONSTRUCTION FOR ANY OF THE MITCHELL ENVIRONMENTAL PROJECTS IN THE 2014 PLAN?

A. No. The Company has not sought a CPCN for any of the Mitchell environmental projects included in the 2014 Plan. These projects were underway at the time of the Mitchell Transfer and were identified during Case No. 2012-00578 as environmental works in progress. The project costs were included in the economic modeling performed by the Company in support of Mitchell Transfer.

Q. IS THE COMPANY PROPOSING TO INCLUDE CONSUMABLES FOR THE MITCHELL PLANT OTHER THAN THOSE WHICH HAVE PREVIOUSLY BEEN INCLUDED IN THE ENVIRONMENTAL SURCHARGE?

A. Yes. The Company is proposing to recover the costs of all consumables used in the operation of the approved environmental projects including polymer and lime hydrate. Additionally, the Company is proposing to include costs associated with limestone, trona, and urea which have previously been included in the Company's share of the Mitchell environmental projects under the AEP East-System Pool.

<u>Rockport Environmental Projects</u>

Q. IS KENTUCKY POWER REQUESTING APPROVAL TO INCLUDE ENVIRONMENTAL PROJECTS FOR FACILITIES OTHER THAN THE MITCHELL PLANT?

A. Yes. Kentucky Power is seeking to include in the 2014 Plan in-service projects and near-term planned projects for the Rockport Power Plant located in Rockport, Indiana. Kentucky Power is a party to a FERC-approved unit power agreement ("UPA") with AEP Generating Company that expires in 2022. Under the UPA, Kentucky Power receives 30% of AEP Generating Company's 50% share of the generation output at these two generating units and is responsible for 30% of AEP Generating Company's costs.

Q. PLEASE LIST THE ROCKPORT PLANT'S ENVIRONMENTAL PROJECTS THE COMPANY IS PROPOSING TO ADD IN THE 2014 COMPLIANCE PLAN.

A. Kentucky Power proposes to add the following Mitchell Plant environmental projects through the 2014 Plan:

- Precipitator Modifications – Rockport Plant Units 1 & 2;
- Activated Carbon Injection (ACI) and Mercury Monitoring – Rockport Plant Units 1 & 2;
- Dry Sorbent Injection – Rockport Plant Units 1 & 2; and
- Coal Combustion Waste Landfill Upgrade to Accept Type 1 Ash – Rockport Plant.

Q. PLEASE LIST THE ROCKPORT PROJECTS INCLUDED IN THE PROPOSED 2014 PLAN BUT ARE NOT YET IN SERVICE.

A. Kentucky Power is including in the 2014 Plan the following Rockport environmental projects that are not yet in service:

- Dry Sorbent Injection ("DSI") for Rockport Plant Units 1 and 2; and
- Portions of the coal combustion waste landfill upgrade are not yet complete.

Q. OF THE PROJECTS WHICH ARE CURRENTLY IN SERVICE FOR ROCKPORT, WAS KENTUCKY POWER BEING BILLED FOR ITS SHARE OF THE COST DURING THE TEST YEAR?

A. Yes. Kentucky Power was receiving its appropriate share of the costs through the Rockport Unit Power Bill.

Q. IS THE COMPANY ALSO PROPOSING TO RECOVER, THROUGH THE ENVIRONMENTAL SURCHARGE, ITS SHARE OF CONSUMABLE EXPENSES FOR THE ROCKPORT PLANT?

A. Yes. The Company is proposing to recover the costs of all consumables used in the operation of the approved environmental projects including the brominated activated carbon used by the ACI system and the sodium bicarbonate that will be used by the DSI system.

Emission Allowances

Q. IS THE COMPANY PROPOSING TO ADD ANY NEW CATEGORIES OF EMISSION ALLOWANCES IN THE 2014 PLAN?

A. Yes. The Company is adding "Costs Associated with the CSAPR Allowances" as an environmental project in the 2014 Plan.

Q. HOW ARE THE EMISSION ALLOWANCES ACCOUNTED FOR BY KENTUCKY POWER?

A. Emission allowances are accounted for differently for compliance and accounting purposes. For compliance purposes, allowances are held and the allowances are surrendered to match consumption. From an accounting perspective, emission allowances are kept on the company's books at an average inventory cost of the allowances held. For instance, when Cross-State Air Pollution Rule ("CSAPR") emission allowances are allocated by the EPA, they are done so at zero cost. As such, using these allowances for consumption would result in zero dollars in emission expense. However, if Kentucky Power purchases allowances to meet its emission obligation, then (subsequent to purchase) each allowance held will be valued at the average cost of all allowances held in inventory including those allocated and purchased.

Q. DOES KENTUCKY POWER PLAN TO ACCOUNT FOR CSAPR ALLOWANCES DIFFERENTLY THAN THOSE ALLOWANCES ASSOCIATED WITH PRIOR ENVIRONMENTAL REGULATIONS?

A. No. Kentucky Power has been accounting for, and recovering costs associated with, Title IV SO_2 allowances under the Clean Air Act as well as SO_2 and NO_x allowances under the Clean Air Interstate Rule ("CAIR") over the lives of those rules. In accordance with FERC Uniform System of Accounts CSAPR emission allowances will be held in different sub-accounts to differentiate between them from allowances created under other regulations , but the allowances themselves will be subject to the same accounting procedures regarding value, gains and losses, and surrender, as the allowances under the other regulations. Kentucky Power also is proposing to recover the CSAPR emission allowances costs in the same manner as other environmental regulations, which is through the Environmental Surcharge.

Q. IS IT REASONABLE FOR KENTUCKY POWER TO RECOVER THESE PRUDENTLY INCURRED COSTS ASSOCIATED WITH CSAPR EMISSIONS ALLOWANCES?

A. Yes. CSAPR is, in part, a replacement for CAIR, and Kentucky Power is proposing to recover the cost of emission allowances under CSAPR just as it has previously done under Title IV of the Clean Air Act and the CAIR. Other than the fact that the allowances were created under a different rulemaking, there is no difference in the rationale for recovery of the costs associated with emission allowances.

Q. HOW WILL COSTS ASSOCIATED WITH CSAPR ALLOWANCES BE RECOVERED THROUGH THE ENVIRONMENTAL SURCHARGE?

A. Expenses associated with the consumption of the CSAPR allowances will only be recovered through the environmental surcharge as the allowances are consumed. Otherwise, the Company would only earn a return on its inventory of CSAPR allowances.

Q. DOES THE COMPANY CURRENTLY HAVE ANY CSAPR ALLOWANCES?

A. With the reinstatement of CSAPR, US EPA has placed CSAPR allowances in the facility's allowance accounts. Those allowances are allocated at zero cost. In addition, the Company purchased 1,000 CSAPR SO2 allowances in 2011 for $350 each.

Q. IS THE COMPANY'S CURRENT INVENTORY OF CSAPR ALLOWANCES SUFFICIENT?

A. The sufficiency of the Company's inventory of CSAPR allowances is unknown. If the generation output exceeds the current inventory, the Company will need to purchase additional allowances and those costs will flow through the environmental surcharge. There is also the possibility that the Company will have CSAPR allowances in excess of its requirement. If so, any gains on those allowances would also flow through the environmental surcharge.

V. CALCULATION OF MONTHLY ENVIRONMENTAL BASE REVENUE REQUIREMENT

Q. PLEASE EXPLAIN HOW THE MONTHLY ENVIRONMENTAL BASE REVENUE REQUIREMENT WAS CALCULATED.

A. The monthly environmental base revenue requirement was calculated in a step-wise fashion. First, test-year environmental costs were identified on a month-by-month basis. Second, because of the termination of the AEP East-System Pool, pool-related costs incurred by Kentucky Power were removed for those months where the pool still existed (October through December 2013).

Third, environmental project costs for Big Sandy Plant incurred during the test year were removed. As described above, Big Sandy environmental project costs were removed because the Company is retiring Big Sandy Unit 2 no later than May 31, 2015 and, during the transition from coal to natural gas-firing, all Big Sandy Unit 1 costs, including the costs associated with the unit's environmental projects are proposed to be recovered via the Big Sandy 1 Operation Rider.

Fourth, Mitchell Plant test year environmental project costs, exclusive of the costs associated with the Mitchell FGD system, were added. The treatment of Mitchell FGD costs is discussed later in my testimony. Because the Mitchell Transfer did not occur until December 31, 2013, Mitchell environmental project costs for October through December 2013 were not included in the test year data. Accordingly, the Company annualized the non-FGD environmental projects costs for the Mitchell plant.

Finally, the Company added additional Rockport test year expenses for operation and maintenance, depreciation, and return on rate base.

The derivation of the monthly environmental base revenue requirement can be found at Exhibit AJE-3.

Q. WERE ALL OF THE COSTS FOR THE PROPOSED ENVIRONMENTAL PROJECTS INCLUDED IN THE BASE MONTHLY ENVIRONMENTAL COST CALCULATION?

A. No. To properly identify the base level of environmental project costs, only the costs associated with projects which were in-service during the test year were included in the base level calculation. The current revenue requirement, as calculated in each month's environmental surcharge filing, will include the actual costs associated with in-service and approved environmental projects.

Gross Revenue Conversion Factor

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS GROSS REVENUE CONVERSION FACTOR?

A. Yes. As part of this case, the Company is proposing two changes to its method of calculating the gross revenue conversion factor ("GRCF") used to calculate the rate base amount of environmental expenses. First, the Company is proposing to remove the Section 199 manufacturing deduction. The rationale for removing the Section 199 deduction is described in the testimony of Company Witness Bartsch. Second, the Company is proposing to apply a gross-up factor to the short-term debt, long-term debt, and accounts receivable financing that incorporates the Public Service Commission Assessment fee of 0.1952% and the uncollectible expense amount of 0.30%.

Q. WAS THE SECTION 199 DEDUCTION PREVIOUSLY APPLIED TO THE GROSS REVENUE CONVERSION FACTOR FOR ALL OF THE PROJECTS?

A. No. In accordance with Commission Order Dated September 7, 2005, the Company has not included a Section 199 deduction in the GRCF used for calculating the environmental base for the Rockport Plant.

VI. CHANGES TO THE ENVIRONMENTAL SURCHARGE TARIFF (TARIFF E.S.)

Q. ARE THERE ANY PROPOSED CHANGES TO TARIFF E.S.?

A. Yes. The Company is proposing several changes to Tariff E.S. First, the Company is proposing to eliminate the Environmental Surcharge Factor that was authorized by the Commission in Case No. 2012-00578. Second, the Company is updating Tariff E.S. to reflect the new monthly base environmental costs as described above. Third, the Company is modifying the Tariff to reflect the Rate of Return proposed in this case. Fourth, the

Company is updating the revenue allocation and environmental surcharge factor calculations. Finally, the Company is updating the list of environmental projects to match those included in the 2014 Plan.

Q. WHAT RATES OF RETURN ON EQUITY IS THE COMPANY PROPOSING FOR USE WITH THE ENVIRONMENTAL SURCHARGE?

A. The Company is proposing a 10.62% return on equity for non-Rockport environmental projects. This rate of return is supported in the testimony of Company Witnesses Avera and McKenzie. The Company's return on equity for environmental projects at the Rockport Plant is 12.16% as established by the FERC-approved Rockport UPA.

Q. PLEASE DESCRIBE THE CHANGE IN THE METHODOLOGY FOR ALLOCATING THE ENVIRONMENTAL REVENUE REQUIREMENT AMONG CUSTOMER CLASSES.

A. The Company will continue its current allocation methodology for allocating the environmental revenue requirement between retail and full requirements customers. Pursuant to Paragraph 6 of the Stipulation and Settlement Agreement in Case No. 2012-00578 approved by the Commission's Order dated October 7, 2013 ("Stipulation and Settlement Agreement"), the Company will allocate the retail share of the environmental revenue requirement between residential and non-residential customers based on the respective share of total revenues. The Company will include the allocation in its monthly environmental surcharge filings.

Q. HOW DID THE COMPANY MODIFY THE MONTHLY ENVIRONMENTAL SURCHARGE FACTOR FORMULA?

A. In accordance with Paragraph 6 of the Stipulation and Settlement Agreement, Kentucky Power will continue to calculate the monthly environmental surcharge factor for residential customers as a function of total revenues. The Company will now calculate the monthly environmental surcharge factor for non-residential retail customers as a function of non-fuel revenues. It is this final calculation, which is specified in the Stipulation and Settlement Agreement, that is a change from the current methodology.

Q. WILL THE PROPOSED CHANGES TO TARIFF E.S. REQUIRE ANY CHANGES TO THE MONTHLY ENVIRONMENTAL SURCHARGE FORMS?

A. Yes. Although the monthly forms were revised in January 2014 to remove the schedules for pool-related environmental projects, the current schedules do not include the Mitchell environmental projects. Also, the current monthly forms do not provide for the change in the allocation methodology for non-residential retail customers described above.

VII. <u>RECOVERY OF COSTS ASSOCIATED WITH THE MITCHELL FGD</u>

Q. WHY WERE THE MITCHELL FGD COSTS NOT INCLUDED IN THE BASE ENVIRONMENTAL COSTS?

A. Paragraph 6 of the Stipulation and Settlement Agreement requires that all costs associated with the Mitchell FGD system be recovered through the environmental surcharge and excluded from base rates. This recovery mechanism is to remain in place at least until the Commission sets new base rates for a period commencing after June 30, 2020 that includes the Mitchell FGD costs.

Q. DID YOU PREPARE ANY RATE CASE ADJUSTMENTS TO REMOVE KENTUCKY POWER'S SHARE OF THE COSTS ASSOCIATED WITH THE MITCHELL FGD FROM THE TEST YEAR DATA?

A. Yes. Please refer to W35 and W53 within Section V, Exhibit 2. I prepared Adjustment W35 to remove annualized costs associated with the Mitchell FGD operations and maintenance expenses. Because Paragraph 6 of the Stipulation and Settlement Agreement requires that the Company recover all costs associated with the Mitchell FGD via the environmental surcharge, the Mitchell FGD O&M adjustment also includes the costs associated with gypsum disposal, limestone, lime hydrate, and polymer in addition to the depreciation, maintenance, and property tax expenses. After applying the production demand allocation factor, the total adjustment amount is $14,879,350.

Additionally, I prepared Adjustment W53 to remove the rate base amount of the Mitchell FGD. The rate base deduction was determined by removing the accumulated depreciation and accumulated deferred income tax amounts from the electric plant in service amount. The production demand allocation factor was then applied, resulting in a rate base deduction of $223,164,406.

Q. DID YOU CALCULATE THE ANNUAL REVENUE REQUIREMENT FOR COSTS ASSOCIATED WITH THE MITCHELL FGD THAT WILL BE RECOVERED THROUGH THE ENVIRONMENTAL SURCHARGE?

A. Yes. I determined what the annual revenue requirement for the Mitchell FGD based on the period from July 2015 through June 2016.

Q. WHY DID YOU CALCULATE THE ANNUAL REQUIREMENT BASED ON THE PERIOD FROM JULY 2015 THROUGH JUNE 2016?

A. I utilized the July 2015 through June 2016 period because that is the first 12 month period following the anticipated date that the rates proposed in this case will go in to effect.

Q. PLEASE DESCRIBE THE PROCESS YOU USED TO CALCULATE THE ANNUAL REVENUE REQUIREMENT TO RECOVER COSTS ASSOCIATED WITH THE MITCHELL FGD.

A. The derivation of the annual revenue requirement for the Mitchell FGD of $34,391,339 is shown on Exhibit AJE-4. As I did in developing the monthly environmental base revenue requirement, I calculated the revenue requirement for the Mitchell FGD in a step-wise fashion. The step-wise process I utilized produced monthly revenue requirements, which I subsequently summed for the annual period described above.

First, I determined the Mitchell FGD rate base by subtracting the monthly depreciation amount and the monthly accumulated deferred federal income tax ("ADFIT") amount from Kentucky Power's share of the original cost of the Mitchell FGD. Next, I calculated the monthly return on rate base utilizing the weighted average cost of capital ("WACC") proposed in this case.

I then added the month return on rate base values to the monthly operation and maintenance ("O&M") expenses associated with the Mitchell FGD. To determine the monthly Mitchell O&M expenses, I utilized the annualized test year operation and maintenance expenses associated with the Mitchell FGD. The addition of the monthly return on rate base requirement with the monthly O&M expenses produces a total monthly revenue requirement for the costs associated with the Mitchell FGD. I next applied the estimated retail allocation factor to determine the monthly retail revenue requirement for the Mitchell FGD.

My final step was to sum the monthly revenue requirements for the annual period from July 2015 through June 2016

Q. WHAT DEPRECIATION RATE WAS USED TO CALCULATE THE DEPRECIATION EXPENSE FOR THE MITCHELL FGD?

A. As is reflected in the exhibits of Company Witness Davis, the Company is proposing a 3.13% depreciation rate for projects within account 312 – Boiler Plant Equipment. This is the depreciation rate utilized in developing the depreciation expense for the Mitchell FGD.

Q. WHAT COST OF EQUITY RATE DID THE COMPANY USE TO CALCULATE THE REVENUE REQUIREMENT FOR THE MITCHELL FGD?

A. The WACC, as calculated on Exhibit AJE-5 and utilized to calculate the required monthly return on rate base for the Mitchell FGD, included the 10.62% rate of return on equity proposed by the Company in this case. The basis for using a 10.62% rate of return is included in the testimony of Company Witnesses Avera and McKenzie.

V. CONCLUSION

Q. IS IT FAIR, JUST, AND REASONABLE TO RECOVER, THROUGH EITHER THE ENVIRONMENTAL SURCHARGE OR BASE RATES THE ENVIRONMENTAL COSTS ASSOCIATED WITH THE 2014 ENVIRONMENTAL COMPLIANCE PLAN?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Kentucky Power Company's Previously Approved Environmental Compliance Projects				
Project	**Plant**	**Pollutant**	**Description**	**In-Service Year**
1	Mitchell	NO_X, SO_2, and SO_3	Mitchell Units 1 and 2 Water Injection, Low NO_X Burners, Low NO_X Burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation	1993-1994-2002-2007
2	Mitchell	SO_2 , NO_X, and Gypsum	Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities	1993-2004-2007
3	Rockport	SO_2 / NO_X	Continuous Emission Monitors (CEMS) - Rockport Plant	1994
4	Rockport	NO_X, Fly Ash, and Bottom Ash	Rockport Units 1 and 2 Low NOX Burners, Over Fire Air, and Landfill	2003-2008
5	Mitchell and Rockport	SO_2/NO_X/Particulates/VOC and etc.	Title V Air Emission Fees at Mitchell and Rockport Plants	Annual
6	Big Sandy, Mitchell, and Rockport	NO_X	Costs Associated with Nox Allowances	As-Needed
7	Big Sandy, Mitchell, and Rockport	SO_2	Costs Associated with SO_2 Allowances	As-Needed

Kentucky Power Company's Proposed Environmental Compliance Projects				
Project	**Plant**	**Pollutant**	**Description**	**In-Service Year**
8	Big Sandy, Mitchell, and Rockport	SO_2 / NO_X	Costs associated with the CSAPR Allowances	As-Needed
9	Mitchell	Particulates	Precipitator Modifications - Mitchell Plant Units 1 and 2	2007-2013
10	Mitchell	Particulates	Bottom Ash and Fly Ash Handling - Mitchell Plant Units 1 and 2	2008 & 2010
11	Mitchell	Mercury	Mercury Monitoring (MATS) - Mitchell Plant Units 1 and 2	2014
12	Mitchell	Selenium	Dry Fly Ash Handling Conversion - Mitchell Plant Units 1 and 2	2014
13	Mitchell	Fly Ash, Bottom Ash, Gypsum, and WWTP Solids	Coal Combustion Waste Landfill - Mitchell Plant Units 1 and 2	2014 & 2015
14	Mitchell	Particulates	Electrostatic Precipitator Upgrade - Mitchell Plant Unit 2	2015
15	Rockport	Particulates	Precipitator Modifications - Rockport Plant Units 1 & 2	2004-2009
16	Rockport	Mercury	Activated Carbon Injection (ACI) and Mercury Monitoring - Rockport Plant Units 1 & 2	2009-2010
17	Rockport	HAPS	Dry Sorbent Injection - Rockport Plant Units 1 and 2	2015
18	Rockport	Fly Ash and Bottom Ash	Coal Combustion Waste Landfill Upgrade To Accept Type 1 Ash -- Rockport Plant	2013 & 2015

TARIFF E.S.
(Environmental Surcharge)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., ~~Experimental~~ S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ~~Q.P., C.I.P.-T.O.D.,~~ *I.G.S.,* C.S.- I.R.P., M.W., O.L., and S.L. T T

RATE.

~~In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Monthly Environmental Surcharge Factor will be fixed and maintained at 0.00% until new base rates are first established by Commission after the effective date of this tariff without regard to the calculation of the Monthly Environmental Surcharge Factor under paragraphs 1 through 4 below. Also, t~~ D D

The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph ~~3~~ 2 below and in the current period as provided in Paragraph 3 below. N N

The retail share of the revenue requirement will ~~then~~ be allocated between residential and non-residential retail customers based upon their respective total revenues *during the previous calendar year.* The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers. ~~when new base rates are established.~~ N T

~~1. The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 3 below and in the current period according to the following formula:~~ D

~~Monthly Environmental Surcharge Factor = Net KY Retail E(m) / KY Retail R(m)~~

~~Where:~~

~~Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.~~

~~(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)~~

~~KY Retail R(m) = Kentucky Retail Revenues for the Expense Month.~~ D

1. ~~2.~~ Monthly Environmental Surcharge Gross Revenue Requirement, E(m) T

Where:	E(m)	=	CRR - BRR
	CRR	=	Current Period Revenue Requirement for the Expense Month.
	BRR	=	Base Period Revenue Requirement.

(Continued on Sheet 29-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 2, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

2.~~3.~~ Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month	Base Net Environmental Costs		
JANUARY	$ ~~3,991,163~~	*$ 2,750,919*	R
FEBRUARY	~~3,590,810~~	*$ 2,738,884*	R
MARCH	~~3,651,374~~	*$ 2,851,531*	R
APRIL	~~3,647,040~~	*$ 2,909,965*	R
MAY	~~3,922,590~~	*$ 2,897,250*	R
JUNE	~~3,627,274~~	*$ 2,835,973*	R
JULY	~~3,805,325~~	*$ 3,567,407*	R
AUGUST	~~4,088,830~~	*$ 3,319,549*	R
SEPTEMBER	~~3,740,010~~	*$ 3,378,515*	R
OCTOBER	~~3,260,302~~	*$ 3,097,929*	R
NOVEMBER	~~2,786,040~~	*$ 2,994,579*	I
DECEMBER	~~4,074,321~~	*$ 2,996,160*	R
	~~$ 44,185,079~~	*$ 36,338,660*	R

In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Mitchell FGD and all related associated costs are not included in base rates or the Base Revenue Requirement but will be included in the Current Period Revenue Requirement. The Mitchell FGD will be excluded from Base Rates at least until June 30, 2020. N–N

3.~~-4.~~ Current Period Revenue Requirement, CRR T

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} + [((RB_{IM(c)})\ (ROR_{IM(c)})/12) + OE_{IM(c)}]\ (.15) - AS]$$

Where:

$RB_{KP(C)}$ = Environmental Compliance Rate Base for ~~Big Sandy.~~ *Mitchell.* T

$ROR_{KP(C)}$ = Annual Rate of Return on ~~Big Sandy~~ *Mitchell* Rate Base; T
Annual Rate divided by 12 to restate to a Monthly Rate of Return.

(Cont'd on Sheet 29-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

$OE_{KP(C)}$ = Monthly Pollution Control Operating Expenses for ~~Big Sandy~~. *Mitchell.* T

$RB_{IM(C)}$ = Environmental Compliance Rate Base for Rockport.

$ROR_{IM(C)}$ = Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.

$OE_{IM(C)}$ = Monthly Pollution Control Operating Expenses for Rockport.

AS = Net proceeds from the sale of *Title IV and CSAPR* SO_2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. ~~The SO_2 allowance sales can be from either EPA Auctions or the AEP Interim Allowance Agreement Allocations.~~ T T

"KP(C)" identifies components from ~~the Big Sandy~~ *Mitchell* Units – Current Period, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period. T

The Rate Base for both Kentucky Power and Rockport should reflect the current costs associated with the 1997 Plan, ~~and~~ *the* 2003 Plan, *the 2005 Plan, the 2007 Plan and the 2014 Plan.* The Rate Base for Kentucky Power should also include a cash working capital allowance based on the 1/8 formula *a*pproach, due to the inclusion of Kentucky Power's accounts receivable financing in the capital structure and weighted average cost of capital. The Operating Expenses for both Kentucky Power and Rockport should reflect the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, ~~and~~ the 2007 Plan, *and the 2014 Plan.* T T

The Rate of Return for Kentucky Power is ~~10.50%~~ *10.62%* rate of return on equity as authorized by the Commission in its ~~June 29, 2010~~ Order *Dated XXXXXXXX* in Case No. *2014-00396* ~~2009-00459 at page 6~~. T T

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

(Cont'd on Sheet No. 29-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-4**
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 29-4

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

4. *Revenue Allocation* N

$$\text{Residential Allocation } RA(m) = \frac{\text{KY Residential Retail Revenue } RR(b)}{\text{KY Retail Revenue } R(b)}$$

$$\text{All Other Allocation } OA(m) = \frac{\text{KY All Other Classes Retail Revenue } OR(b)}{\text{KY Retail Revenue } R(b)}$$

Where:
(m) = the expense month
(b) = most recent calendar year revenues

5. *Environmental Surcharge Factor*

$$\text{Residential Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail } E(m) \;*\; RA(m)}{\text{KY } RR(m)}$$

$$\text{All Other Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail } E(m) \;*\; AO(m)}{\text{KY } OR(m) - \text{KY } OF(m)}$$

Where:
Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/ (Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non -Physical Revenues.)

RR(m) = Kentucky Residential Retail Revenues for the Expense Month.

OR(m) = Kentucky All Other Classes Retail Revenues for the Expense Month

OF(m) = Kentucky All Other Classes Fuel Revenues for the Expense Month N

(Cont'd on Sheet No. 29-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

~~6.5.~~ Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows: T

Total Company:

~~(a) costs associated with Continuous Emission Monitors (CEMS)~~ D

~~(b) costs associated with the terms of the Rockport Unit Power Agreement~~ D

~~(c) the Company's share of the pool capacity costs associated with Gavin scrubber(s)~~ D

- return on *Title IV and CASPR* SO_2 allowance inventory T

~~(d) costs associated with air emission fees *at Rockport and Mitchell*~~ D

- ~~(b)~~ over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge T

- ~~(c)~~ costs associated with any Commission's consultant approved by the Commission T

~~(h) cost associated with Low Nitrogen Oxide (NOx) burners at the Big Sandy Generating Plant~~ D

- ~~(d)~~ costs associated with the consumption *Title IV and CSAPR* of SO_2 allowances T

~~• costs associated with the Selective Catalytic Reduction (SCR) at the Big Sandy Generating Plant~~ D

~~(i) costs associated with the upgrade of the precipitator at the Big Sandy Generating Plant~~ D

~~(j) costs associated with the over-fire air with water injection at the Big Sandy Generating Plant~~ D

- ~~(e)~~ costs associated with the consumption of NO_x allowances T

- ~~(f)~~ return on NO_x allowance inventory T

~~(k) 25% of the costs associated with the Reverse Osmosis Water System (the amount is subject to adjustment at subsequent 6-month surcharge reviews based on the documented utilization of of the RO Water System by the SCR)~~ D

- ~~(g)~~ costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor) T

- Costs associated with consumables used in conjunction with approved environmental projets.

(Cont'd on Sheet No. 29-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 DATED XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-6**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 29-6

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

The Company's share of costs associated with the following environmental equipment at the Rockport Plant: N

- *Continuous Emissions Monitors*
- *Air Emission Fees*
- *Costs Associated with the Rockport Unit Power Agreement*
- *Activated Carbon Injection*
- *Mercury Monitoring*
- *Precipitator Modifications*
- *Dry Sorbent Injection*
- *Coal Combustion Waste Landfill*
- *Low NOx burners, over-fire air, Landfill*

The Company's share of costs associated with the following environmental equipment at the Mitchell Plant: N

~~*(I)* the Company's share of the pool capacity costs associated with the following:~~ D

- ~~Amos Unit No. 3 CEMS, Low NO_x Burners, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation~~ D
- ~~Cardinal Unit No 1 CEMS, Low NO_x Burners, SCR, Catalyst Replacement, FGD, Landfill and SO_3 Mitigation~~ D
- ~~Gavin Plant SCR and SCR Catalyst Replacement~~ D
- ~~Gavin Unit No 1 and 2 Low NO_x Burners and SO_3 Mitigation~~ D
- ~~Kammer Unit Nos 1, 2 and 3 CEMS, Over Fire Air and Duct Modification~~ D
- Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners, Low NO_x burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities
- *Air Emission Fees* N
- *Precipitator Modifications and Upgrades*
- *Coal Combustion Waste Landfill*
- *Bottom Ash and Fly Ash Handling*
- *Mercury Monitoring (MATS)*
- *Dry Fly Ash Handling Conversion* N

(Cont'd on Sheet No. 29-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

- ~~Muskingum River Unit No 1 Low NO_x Ductwork, Over Fire Air , Over Fire Air Modification, Water Injection and Water Injection Modification~~ D
- ~~Muskingum River Unit No 2 Low NO_x Ductwork, Over Fire Air, Over Fire Air Modification and Water Injection~~
- ~~Muskingum River Unit No 3 Over Fire Air, Over Fire Air Modification with NO_x Instrumentation~~
- ~~Muskingum River Unit No 4 Over Fire Air with Modification~~
- ~~Muskingum River Unit No 5 Low NO_x Burner with Modification and Weld Overlay, an SCR and SO3 Mitigation~~
- ~~Muskingum River Common CEMS~~
- ~~Phillip Sporn Unit No 2 Low NO_x Burners with Modifications~~
- ~~Phillip Sporn Unit No 4 and 5 Low NO_x Burners and Modulating Injection Air system with Modifications~~
- ~~Phillip Sporn Common CEMS, SO_3 Injection System and Landfill~~
- ~~Rockport Unit No 1 and 2 Low NO_x Burners and Landfill~~
- ~~Tanners Creek Unit No 1 Low NO_x Burners, with Modifications and Low NO_x Burners Leg Replacement~~
- ~~Tanners Creek Unit No 2 and 3 Low NO_x Burners with Modifications~~
- ~~Tanners Creek Unit No 4 Over Fire Air, Low NO_x Burners and ESP Controls Upgrade~~
- ~~Tanners Creek Common CEMS and Coal Blending Facilities~~
- ~~Title V Air Emission Fees at Amos, Cardinal, Gavin, Kammer, Mitchell, Muskingum River, Philip Sporn, Rockport and Tanners Creek plants.~~ D

7. ~~6.~~ The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission. T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

Kentucky Power Company
Calculation of Monthly Base Amount of Environmental Costs
October 1, 2013 to September 30, 2014

Ln No (1)	Month / Year (2)	Monthly Environmental Costs (3)	Adjustment for Pool Termination (4)	Adjustment to Remove Big Sandy (5)	Leaves only Test Year Rockport Expenses and Gains on Allowances (6) (3) + (4) + (5)	Include Mitchell Non-FGD (7)	Rockport Additional Test Year Expenses for O & M, Depreciation, and Return (8)	Adjusted Environmental Base (9)
1	October 2013	$2,588,033	-$884,674	-$1,672,931	$30,428	$2,899,309	$137,763	$3,097,929
2	November 2013	$2,574,766	-$873,779	-$1,686,320	$14,667	$2,899,309	$65,935	$2,994,579
3	December 2013	$3,956,730	-$921,717	-$3,000,383	$34,630	$2,899,309	$27,591	$2,996,160
4	January 2014	$2,819,234	$0	-$2,789,805	$29,429	$2,662,142	$29,919	$2,750,919
5	February 2014	$2,727,758	$0	-$2,688,504	$39,254	$2,628,599	$31,777	$2,738,884
6	March 2014	$2,361,529	$0	-$2,321,728	$39,801	$2,699,971	$71,957	$2,851,531
7	April 2014	$2,844,327	$0	-$2,804,712	$39,615	$2,746,874	$83,860	$2,909,965
8	May 2014	$2,450,433	$0	-$2,409,658	$40,775	$2,729,467	$86,233	$2,897,250
9	June 2014	$2,788,301	$0	-$2,749,455	$38,846	$2,693,526	$64,756	$2,835,973
10	July 2014	$2,675,318	$0	-$2,638,192	$37,126	$3,456,665	$36,490	$3,567,407
11	August 2014	$2,796,292	$0	-$2,758,034	$38,258	$3,209,974	$33,058	$3,319,549
12	September 2014	$2,146,708	$0	-$2,108,067	$38,641	$3,266,568	$34,665	$3,378,515
	Total	$32,729,430	-$2,680,170	-$29,627,789	$421,471	$34,791,713	$704,005	$36,338,660

* Per Monthly ES Form 1.00, Line 1

Kentucky Power Company
Mitchell FGD Revenue Requirement

Month (1)	Year (2)	Environmental Utility Plant at Original Cost (3)	Accumulated Depreciation (4)	Monthly Depreciation (5)	ADFIT (6)	Monthly ADFIT (7)	Rate Base (8)	WACC (9)	Monthly Return on Rate Base (10)	Monthly O & M (11)	Total FGD Monthly Environmental Revenue Requirement (12)	Retail Allocation (13)	Proposed Revenue Increase (14)
Balance as of September 30, 2014		$327,193,412	$76,112,982		$24,747,361		$226,333,069						
October	2014	$327,193,412	$76,966,411	$853,429.48	$24,867,276	$119,915	$225,359,724	10.79%	$2,026,360	$1,257,552	$3,283,911	0.9076	$2,980,478
November	2014	$327,193,412	$77,819,841	$853,429.48	$24,987,191	$119,915	$224,386,380	10.79%	$2,017,608	$1,257,552	$3,275,159	0.9076	$2,972,534
December	2014	$327,193,412	$78,673,270	$853,429.48	$25,107,106	$119,915	$223,413,035	10.79%	$2,008,856	$1,257,552	$3,266,407	0.9076	$2,964,591
January	2015	$327,193,412	$79,526,700	$853,429.48	$25,220,819	$113,713	$222,445,893	10.79%	$2,000,159	$1,278,321	$3,278,480	0.9076	$2,975,549
February	2015	$327,193,412	$80,380,129	$853,429.48	$25,334,532	$113,713	$221,478,750	10.79%	$1,991,463	$1,186,493	$3,177,956	0.9076	$2,884,313
March	2015	$327,193,412	$81,233,559	$853,429.48	$25,448,245	$113,713	$220,511,608	10.79%	$1,982,767	$1,310,939	$3,293,706	0.9076	$2,989,367
April	2015	$327,193,412	$82,086,988	$853,429.48	$25,561,958	$113,713	$219,544,466	10.79%	$1,974,071	$1,373,764	$3,347,834	0.9076	$3,038,495
May	2015	$327,193,412	$82,940,418	$853,429.48	$25,675,671	$113,713	$218,577,323	10.79%	$1,965,374	$1,307,932	$3,273,307	0.9076	$2,970,853
June	2015	$327,193,412	$83,793,847	$853,429.48	$25,789,384	$113,713	$217,610,181	10.79%	$1,956,678	$1,178,850	$3,135,528	0.9076	$2,845,805
July	2015	$327,193,412	$84,647,277	$853,429.48	$25,903,097	$113,713	$216,643,038	10.79%	$1,947,982	$1,367,810	$3,315,792	0.9076	$3,009,413
August	2015	$327,193,412	$85,500,706	$853,429.48	$26,016,810	$113,713	$215,675,896	10.79%	$1,939,286	$1,081,502	$3,020,788	0.9076	$2,741,667
September	2015	$327,193,412	$86,354,136	$853,429.48	$26,130,523	$113,713	$214,708,753	10.79%	$1,930,590	$1,232,354	$3,162,943	0.9076	$2,870,687
October	2015	$327,193,412	$87,207,565	$853,429.48	$26,244,236	$113,713	$213,741,611	10.79%	$1,921,893	$1,257,552	$3,179,445	0.9076	$2,885,664
November	2015	$327,193,412	$88,060,995	$853,429.48	$26,357,949	$113,713	$212,774,468	10.79%	$1,913,197	$1,257,552	$3,170,749	0.9076	$2,877,771
December	2015	$327,193,412	$88,914,424	$853,429.48	$26,471,662	$113,713	$211,807,326	10.79%	$1,904,501	$1,257,552	$3,162,052	0.9076	$2,869,879
January	2016	$327,193,412	$89,767,854	$853,429.48	$26,584,504	$112,842	$210,841,054	10.79%	$1,895,812	$1,278,321	$3,174,133	0.9076	$2,880,843
February	2016	$327,193,412	$90,621,283	$853,429.48	$26,697,346	$112,842	$209,874,783	10.79%	$1,887,124	$1,186,493	$3,073,617	0.9076	$2,789,615
March	2016	$327,193,412	$91,474,713	$853,429.48	$26,810,188	$112,842	$208,908,511	10.79%	$1,878,436	$1,310,939	$3,189,375	0.9076	$2,894,677
April	2016	$327,193,412	$92,328,142	$853,429.48	$26,923,030	$112,842	$207,942,240	10.79%	$1,869,747	$1,373,764	$3,243,511	0.9076	$2,943,811
May	2016	$327,193,412	$93,181,572	$853,429.48	$27,035,872	$112,842	$206,975,968	10.79%	$1,861,059	$1,307,932	$3,168,991	0.9076	$2,876,176
June	2016	$327,193,412	$94,035,001	$853,429.48	$27,148,714	$112,842	$206,009,697	10.79%	$1,852,371	$1,178,850	$3,031,220	0.9076	$2,751,136

Total Revenue Requirement for July 2015 through June 2016 **$34,391,339**

ES FORM 3.15

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
MITCHELL PLANT COST OF CAPITAL

LINE NO.	Component	Balances	Cap. Structure	Cost Rates		WACC (Net of Tax)	GRCF		WACC (PRE-TAX)
		As of 9/30/2014							
1	L/T DEBT	$607,976,387	52.984%	5.41%		2.87%	1.0050	***	2.88%
2	S/T DEBT	($30,904,414)	-2.693%	0.38%		-0.01%	1.0050		-0.01%
3	ACCTS REC FINANCING	$51,835,783	4.517%	1.07%		0.05%	1.0050		0.05%
4	C EQUITY	$518,572,572	45.192%	**10.62%**	*	4.80%	**1.6402**	**	7.87%
5	TOTAL	**$1,147,480,328**	**100.000%**						**10.79%**

6	Operating Revenues	100.00
7	Less Uncollectible Accounts Expense	0.3000
8	KPSC Maintenance Assessment Fee	0.1952
9	Income Before Income Taxes	99.5048
10	Gross Up Factor (100.00/Ln 9)	1.0050

* WACC = Weighted Average Cost of Capital
Rate of Return on Common Equity proposed in Case No. 2014-00396

** Gross Revenue Conversion Factor (GRCF) Calculation as reflected in Section V, Schedule 2, Workpaper S-2, Page 2 of 3.

*** Gross Up for PSC Maintenance Assessment Fee & Uncollectible Expense

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For:	)	
(1) A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

DIRECT TESTIMONY OF

JEFFERY D. LAFLEUR

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jeffrey D. LaFleur, being duly sworn, deposes and says he is Vice President Generating Assets APCO/KY, that he has personal knowledge of the matters set forth in the testimony 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

Jeffery D. LaFleur

Jeffery D. LaFleur

STATE OF WEST VIRGINIA)
) Case No. 2014-00396
COUNTY OF KANAWHA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffrey D. LaFleur, this the 10th day of December, 2014.

Dorothy E. Philyaw

Notary Public

OFFICIAL SEAL
STATE OF WEST VIRGINIA
NOTARY PUBLIC
DOROTHY E. PHILYAW
APPALACHIAN POWER
PO BOX 1986
CHARLESTON, WV 25327-1986
My commission expires October 2, 2019

My Commission Expires: October 2, 2019

DIRECT TESTIMONY OF
JEFFERY D. LAFLEUR, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
JEFFERY D. LAFLEUR, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Jeffery D. LaFleur. My title is Vice President – Generating Assets for Kentucky Power Company ("Kentucky Power" or "Company") and Appalachian Power Company ("APCo"). Both Kentucky Power and APCo are wholly owned subsidiaries of American Electric Power ("AEP"). My business address is 707 Virginia Street, East, Suite 1000, Charleston, West Virginia 25301.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the Louisiana Tech University and have completed an executive management program at Louisiana State University.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I joined Southwestern Electric Power Company (another subsidiary of AEP) in 1982 as a staff engineer, progressing to various positions including maintenance supervisor, maintenance superintendent, and plant manager. I became manager of operations over all SWEPCO power plants in 1993. From 1993 through May 2008 I held several positions with Central and Southwest Corporation and other companies within the American Electric Power system, and was responsible for the ongoing operation of generating assets including coal-fired plants, wind generating facilities, and gas-fired combined cycle and peaking units. Specifically, from 2003 to 2008 I served as Vice President of Region 2 generation assets, which included Kentucky Power's Mitchell Plant. I assumed my current position in January 2013.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS VICE PRESIDENT – GENERATING ASSETS FOR KENTUCKY POWER AND APCO?

A. I am responsible for the safe, reliable and economic operation of Kentucky Power and APCo's fossil-fueled and hydro-powered electric generating facilities.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have testified on behalf of Kentucky Power before the Kentucky Public Service Commission ("Commission") in Case No. 2012-00578, and I have also testified on behalf of APCo before regulatory commissions in Virginia and West Virginia.

III. PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my testimony is to:

- Describe the Company's Generation Assets.

- Describe and support the reasonableness of the Generation non-fuel Operations and Maintenance (O&M) expenses for Kentucky Power's 50% undivided share of the Mitchell generating station.
- Describe and support the reasonableness of the Generation non-fuel O&M expenses for Kentucky Power's Big Sandy Plant Unit 1.
- Support the identification and reasonableness of the Big Sandy Unit 1 and other Big Sandy plant coal-related assets to be retired as part of its conversion to a gas-fired unit.
- Support the reasonableness of the Decommissioning O&M expenses for Kentucky Power's Big Sandy Plant Unit 2 after it is retired from service in June 2015.
- Support the reasonableness and cost-effectiveness of the capital projects and non-fuel O&M to be included in the 2014 Environmental Compliance Plan.

IV. KENTUCKY POWER'S GENERATING ASSETS

Q. PLEASE BRIEFLY DESCRIBE KENTUCKY POWER'S GENERATING ASSETS.

A. Kentucky Power owns and operates the coal-fired Big Sandy Plant located in Louisa, Kentucky. The plant, with a total generating capacity of 1,078 net megawatts (MW), comprises two coal-fired generating units. Unit 1 is a 278 MW sub-critical generating unit in service since 1963 and Unit 2 is a 800 MW super-critical generating unit in service since 1969. Both units are equipped with Electrostatic Precipitators (ESPs) for particulate control and low nitrogen oxide

(NO_x), burners (LNBs). Unit 2 is also equipped with a Selective Catalytic Reduction (SCR) system for additional (up to 90%) NO_x reduction. As is discussed further in my testimony, due to the forthcoming compliance deadline with EPA's Mercury and Air Toxics (MATS) Rule Big Sandy Unit 2 will be retired as of June 1, 2015 and Big Sandy Unit 1 will be converted to run on natural gas by approximately June 2016.

In addition to the Big Sandy Plant, Kentucky Power also owns an undivided 50% interest in the Mitchell Plant, located approximately 12 miles south of Moundsville, West Virginia on the Ohio River. The Mitchell Pant comprises two super-critical pulverized coal-fired base load generating units. Unit 1 has a capacity of 770 MW and Unit 2 has a capacity of 790 MW for a total capacity of 1,560 MW. Both units were placed in service in 1971. These units are of the same series and vintage as Big Sandy Unit 2; however, the Mitchell units are considered fully controlled as they are equipped with Flue Gas Desulfurization (FGD) systems for sulfur dioxide (SO_2) and SCR technology for NO_X control. Both units at the Mitchell Plant are also equipped with ESPs, low-NO_x burners, and SCRs, similar to Big Sandy Unit 2.

Lastly, Kentucky Power has a unit power agreement for 15% of the generation from the Rockport Plant. The Rockport Plant is also located along the Ohio River in southern Indiana, and consists of two super-critical pulverized coal-fired base load units. Unit 1 has a capacity of 1,320 MW and Unit 2 has a capacity of 1,300 MW for a total capacity of 2,620 MW. Both of the Rockport Units are equipped with ESPs, low-NO_x burners, and Activated Carbon Injection (ACI) systems for mercury reduction.

Q. WHAT EFFECT WILL THE MATS RULE HAVE ON THE BIG SANDY PLANT?

A. Due to MATS, and as discussed by Company Witness McManus, Kentucky Power will be retiring Big Sandy Unit 2 by June 1, 2015. In accordance with the Commission's October 7, 2013 Order in Case No. 2012-00578, Kentucky Power acquired a 50% undivided interest in the Mitchell generating station to replace Big Sandy Unit 2. In addition to the retirement of Big Sandy Unit 2, Kentucky Power is in the process of converting Big Sandy Unit 1 to consume natural gas rather than coal, pursuant to the Commission's Order in Case No. 2013-00430. This fuel conversion will allow Big Sandy Unit 1 to continue to operate in compliance with the stringent air emission requirements of MATS. Big Sandy Unit 1's conversion to natural gas should be complete by June of 2016.

V. KENTUCKY POWER MITCHELL PLANT NON-FUEL O&M PRODUCTION COSTS TO BE INCLUDED IN BASE RATES

Q. WHAT WAS KENTUCKY POWER'S ANNUALIZED TEST YEAR LEVEL OF GENERATION NON-FUEL O&M EXPENSES (GENERATION O&M) FOR ITS 50% UNDIVIDED SHARE OF MITCHELL PLANT?

A. Kentucky Power's annualized test year level of total non-fuel O&M expense for its undivided 50% interest in Mitchell Plant is $43.42 million, as calculated by Company Witness Yoder. Of the $43.42 million annualized test year level, the costs directly associated with the operation of Mitchell Plant during the annualized test year are $31.13 million (direct generation non-fuel O&M

expense). The remaining $12.29 million includes items such as taxes, employee benefits, and other expenses allocated to Mitchell Plant. All these costs, including the allocated expenses, were reasonable, necessary and prudently incurred to support Mitchell Plant operations.

Q. PLEASE PROVIDE FURTHER DETAIL CONCERNING KENTUCKY POWER'S 50% SHARE OF THE MITCHELL PLANT'S ANNUALIZED TEST-YEAR DIRECT GENERATION NON-FUEL O&M AMOUNTS BY MAJOR CATEGORY?

A. The following Table 1 provides by major category the annualized test-year direct generation non-fuel O&M expenses for the Mitchell Plant:

Category	Mitchell Plant
Allow ance Consumption	$446,540
Ash Sales	($14,423)
Consumables	$6,485,140
Fuel Handling	$5,468,696
Gypsum Operations	($132,464)
Steam Maintenance	$12,474,790
Steam Operations	$6,404,376
Total	**$31,132,656**

Table 1: Kentucky Power Annualized Test-Year Generation Non-Fuel O&M for 50% ML

Q. IS IT NECESSARY TO NORMALIZE ANY PART OF THE $31.1 MILLION IN ANNUALIZED DIRECT NON-FUEL O&M TEST YEAR EXPENSES?

A. Yes. Steam Maintenance work and expenses can vary materially from year to year. The cyclical nature of maintenance expenditures is primarily driven by unit outages and periodic planned repairs and replacements of unit components.

Q. HOW DID KENTUCKY POWER NORMALIZE THE STEAM MAINTENANCE EXPENSES TO REFLECT THE CYCLICAL NATURE OF MAJOR OUTAGE WORK?

A. As described by Company Witness Wohnhas, Kentucky Power is proposing to normalize the annualized Mitchell Steam Maintenance expense using the average for a three year period as adjusted for inflation. This normalization results in a positive adjustment of $3.27 million to the test year level steam maintenance expense of $12,474,790 to produce a normalized and annualized test-year Mitchell Steam Maintenance expense of $15.74 million for Kentucky Power's 50% share of the Mitchell Plant.

Q. DOES THE NORMALIZED AND ANNUALIZED TEST-YEAR MITCHELL STEAM MAINTENANCE EXPENSE OF $15.74 MILLION REPRESENT AN APPROPRIATE AND REASONABLE LEVEL?

A. Yes. This level is reasonable, and fairly reflects an appropriate normalized level of Steam Maintenance expense for Kentucky Power's 50% share of the Mitchell Plant.

VI. KENTUCKY POWER BIG SANDY UNIT 1 GENERATION NON-FUEL O&M EXPENSES TO BE INCLUDED IN THE BS1OR

Q. WHAT IS KENTUCKY POWER'S TEST YEAR LEVEL OF TOTAL NON-FUEL O&M EXPENSE FOR BIG SANDY UNIT 1?

A. Kentucky Power's test year level of total non-fuel O&M expense for Big Sandy Unit 1 is $12.5 million, as calculated by Company Witness Vaughan. Of this $12.5 million, the generation non-fuel O&M expense for Big Sandy Unit 1 during the test year totaled $9.9 million. The remaining $2.6 million of non-fuel O&M expense includes taxes, employee benefits, and other expenses allocated to Big Sandy Unit 1. As with the similar expenses incurred for Mitchell, all of these costs, including the allocated expenses, were reasonable, necessary and prudently incurred to support Big Sandy Unit 1 operations.

Q. PLEASE PROVIDE FURTHER DETAIL CONCERNING BIG SANDY UNIT 1'S TEST-YEAR GENERATION NON-FUEL O&M EXPENSES?

A. The following Table 2 provides the test-year generation non-fuel O&M expenses, incurred by Kentucky Power during the test year, distributed by major category, for Big Sandy Unit 1:

Category	Big Sandy Unit 1
Allowance Consumption	$1,605,774
Fuel Handling	$1,581,916
Steam Maintenance	$4,616,733
Steam Operations	$2,133,730
Total	**$9,938,153**

Table 2: Kentucky Power Test-Year Generation Non-Fuel O&M BSU1

Q. DOES THE TEST YEAR LEVEL OF GENERATION NON-FUEL O&M EXPENSE REPRESENT A REASONABLE ANNUAL EXPENSE LEVEL TO OPERATE BIG SANDY UNIT 1 BEGINNING ON JULY 1, 2015 THROUGH ITS USEFUL LIFE AS A COAL-FIRED UNIT?

A. Yes. The test year Big Sandy Unit 1 generation non-fuel O&M expenses of $9.94 million are a reasonable annual level of the expenses required for Big Sandy Unit 1's continued operation as a coal-fired unit prior to its conversion to natural gas. Specifically, this level of generation non-fuel O&M expense is necessary to operate the unit in a safe and reliable manner while providing cost-effective power for Kentucky Power's customers.

VII. RETIREMENT OF BIG SANDY UNIT 1 COAL-RELATED ASSETS

Q. WHEN WILL KENTUCKY POWER COMPLETE THE CONVERSION OF BIG SANDY UNIT 1?

A. Kentucky Power plans to complete the conversion of Big Sandy Unit 1 to run on natural gas by June 30, 2016.

Q. AFTER THE CONVERSION TO NATURAL GAS WILL BIG SANDY UNIT 1 HAVE COAL-RELATED EQUIPMENT THAT IS NO LONGER USEFUL?

A. Yes. While there will be a significant amount of equipment that will still be necessary to operate Big Sandy Unit 1 as a natural gas-fired facility, some equipment is solely-related to its operation as a coal-fired facility. Examples of Big Sandy Unit 1's coal-related assets include the coal yard and its associated equipment, the conveyors and silos which transfer coal from the coal yard to the plant, the coal pulverizers, the ESPs, and the fly ash and bottom ash handling systems. This equipment will no longer be necessary when the unit is fired by natural-gas, and will be retired once the unit no longer operates as a coal-fired facility.

Q. HOW WERE THE BIG SANDY ORIGINAL PLANT COSTS ALLOCATED BETWEEN UNIT 1 AND UNIT 2?

A. Company Witness Yoder describes the allocation of the total Big Sandy original plant costs between Unit 1 and Unit 2. I performed a review of the projects Company Witness Yoder used in the allocation process, and confirmed that the reviewed projects were properly identified and assigned correctly between Unit 1 and Unit 2.

Q. DID YOU PROVIDE ANY OTHER INPUT INTO THE PROCESS TO IDENTIFY THE AMOUNT OF BIG SANDY ORIGINAL PLANT COSTS RELATED SOLELY TO COAL OPERATIONS?

A. Yes. I reviewed the percentages applied to each property account for Big Sandy Unit 1 to determine the amount of coal-related costs to retire and concluded they were reasonable. These percentages were the result of an analysis performed by the Engineering Services Organization within AEPSC, and are reasonable based on my best professional judgment. While the conversion of Big Sandy Unit 1 to natural gas will eliminate the need for certain equipment associated exclusively with coal-fired operations, the vast majority of the equipment at Big Sandy Unit 1 will continue to be needed when Unit 1 is converted to natural gas.

VIII. BIG SANDY UNIT 2 RETIREMENT COSTS

Q. WHEN WILL KENTUCKY POWER RETIRE BIG SANDY UNIT 2?

A. Kentucky Power will retire Big Sandy Unit 2 by June 1, 2015 to comply with the MATS rule.

Q. WILL KENTUCKY POWER DEMOLISH BIG SANDY UNIT 2 UPON ITS RETIREMENT?

A. No. Big Sandy Unit 1 will still be operational when Big Sandy Unit 2 is retired. It is neither economical nor practical to demolish Big Sandy Unit 2 while Big Sandy Unit 1 is still operating. At the time that Big Sandy Unit 2 is retired Big Sandy Unit 1 will still be operating as a coal-fired unit and will continue to operate as a gas-fired unit after its conversion until its estimated 2031 retirement date. This retirement date for Big Sandy Unit 1 is an estimate and could be extended depending on future conditions and developments. After Big Sandy Unit 1 has been retired, both units will be demolished.

Q. UPON THE RETIREMENT OF BIG SANDY UNIT 2 IN 2015 WILL THERE BE ANY DECOMMISSIONING-RELATED O&M NECESSARY TO MAINTAIN THE UNIT?

A. Yes, after Big Sandy Unit 2 is retired from service there will still be activities necessary to maintain the safety, security, and environmental compliance of the Unit. The total decommissioning-related O&M for Big Sandy Unit 2 is expected to be $6.06 million. The following Table 3 identifies the decommissioning-related O&M, by year, associated with Big Sandy Unit 2 following its retirement.

Period	Decommissioning O&M Expense
July 2015 – June 2016	$1,198,780
July 2016 – June 2017	$880,002
July 2017 – June 2018	$730,000
July – June, 2018 - 2031	$250,000 annually
Total	**$6,058,782**

Table 3: Big Sandy Unit 2 Decommissioning O&M Post-Retirement

Q. WHAT TYPES OF ACTIVITIES ARE REQUIRED TO MAINTAIN BIG SANDY UNIT 2 AFTER ITS RETIREMENT?

A. Even after Big Sandy Unit 2 is retired, the Company will be required to maintain the unit in a safe and secure condition and in compliance with any environmental permits. This will include ensuring fencing, access roads, telecommunication systems, fire water sources, hazardous gas detection systems, emergency lighting, and fire alarm systems are operational. Inspections will need to continue to be performed on structural components such as the cooling tower and plant building to maintain safety. Lastly, environmental requirements such as pond inspections, groundwater and surface water monitoring, and the associated report submittals which accompany these activities must be performed as dictated by the applicable environmental permits.

Q. WHY ARE THE INITIAL DECOMMISSIONING-RELATED O&M COSTS FOLLOWING BIG SANDY UNIT 2'S RETIREMENT HIGHER THAN THOSE IN LATER YEARS?

A. While the activities described previously represent what will be required on an annual basis to maintain safety and environmental compliance at Big Sandy Unit 2, there will be initial one-time activities necessary upon the unit's retirement. Examples of some of these activities include isolating and sealing the river water intake, decommissioning sump pumps, relocating electrical loads, pumping the cooling system empty, draining all tanks and disposing of their contents, and disconnecting all piping above and below ground. After these initial decommissioning-related O&M activities are complete, the year to year activities necessary to maintain safety and environmental compliance, as described above, will levelize on an annual basis at level lower than during the first year of retirement of the Unit.

Q. DO THE DECOMMISSIONING O&M EXPENSES FOR BIG SANDY UNIT 2 REPRESENT AN APPROPRIATE AND REASONABLE LEVEL?

A. Yes. Based upon my professional judgment and experience, this level is reasonable, and fairly reflects those activities necessary to maintain the safety, security, and environmental compliance of the Unit.

IX. GENERATION-RELATED CAPITAL PROJECTS CONTAINED WITHIN THE 2014 ENVIRONMENTAL COMPLIANCE PLAN

Q. ARE THERE ANY SIGNIFICANT CAPITAL PROJECTS FOR MITCHELL AND ROCKPORT PLANTS WHICH ARE BEING PROPOSED FOR INCLUSION IN THE 2014 ENVIRONMENTAL COMPLIANCE PLAN?

A. Yes. Company Witness McManus describes the environmental regulations that necessitate these projects, the costs of which are reflected in data provided by Company Witness Elliott. Here I will provide a general description of these projects and how they affect Kentucky Power's generating assets.

Mitchell Plant (each of these projects was undertaken prior to the transfer of a 50% undivided interest in the Mitchell Plant to Kentucky Power):

- Periodic modifications have been made to the ESPs for Units 1 and 2 to reduce the likelihood that the Units' generation could be curtailed due to opacity limitations. These modifications went into service between 2007 and 2013. Additional upgrades are planned for the Unit 2 ESPs in 2015. The ESPs remove fly ash from the flue gas so that the unit is capable of meeting its opacity and mass emissions limits.
- Periodic modifications and replacement work has been performed on the bottom ash and fly ash handling systems to ensure they are capable of transporting ash for its final disposal. Over time the abrasive nature of the ash degrades the piping and pumps used for its transport which requires

periodic replacement of equipment. These modifications went into service in 2008 and 2010.

- Mercury monitoring equipment has been installed for compliance with the MATS rule. To ensure that the mercury emission limit in the MATS rule is being met, additional monitoring equipment was installed. This equipment was placed in service in 2014.
- The existing wet fly ash handling system was upgraded to a dry handling system. This work required the installation of additional equipment to move the fly ash from the precipitators using air instead of water to mobilize the ash. Additionally, ash silos were installed to store the dry fly ash, and an unloading station was constructed to transport the fly ash for disposal. This dry fly ash handling system was placed in service in 2014.
- A landfill was constructed for the disposal of coal combustion waste. This project was undertaken in conjunction with the dry fly ash conversion project, and the landfill will be used to store the dry ash and replace the existing ash pond. This landfill is located on plant property and required a haul road to be constructed so that the dry fly ash could be trucked from the plant to the landfill. While the landfill and haul road were placed in service in 2014, additional capacity will be added and placed in service in 2015.

Rockport Plant:

- Periodic modifications have been made to the ESPs for units 1 and 2 to reduce the likelihood that the unit's generation could be curtailed due to opacity limitations. These modifications went into service between 2004 and 2009.

- An ACI system has been installed and upgraded to meet the plant's mercury emission limit. The ACI system consists of equipment required to inject powdered activated carbon into the flue gas upstream of the ESPs and capture mercury on the porous surface of the activated carbon. The activated carbon is then removed along with the fly ash in the existing ESPs. Along with the ACI system, a mercury monitor was installed to ensure that the plant's mercury emission limit is met. The ACI system and the mercury monitor were placed in service in 2009 and 2010.
- A dry sorbent injection (DSI) system is currently being installed to remove acid gases from the flue gas stream. The DSI system will inject sodium bicarbonate into the flue gas stream, upstream of the ESPs, which will then react with acid gases. The reacted sodium bicarbonate will then be removed along with the fly ash and activated carbon from the flue gas in the ESPs. The DSI systems on both Rockport units will be in service in the first half of 2015. In conjunction with the DSI project, upgrades will also be made to the ACI system to meet more stringent mercury limits under the MATS Rule.
- Additions to and an upgrade of the coal combustion waste landfill to dispose of the fly ash waste stream being removed by the ESPs. Rockport Plant operates a dry fly ash handling system which produces a waste stream that is disposed of in the plant's on-site landfill. As part of normal ongoing plant operations, additional landfill capacity is constructed to

ensure this waste can be properly disposed. Additionally, with the installation of the DSI system and the injection of sodium bicarbonate into the flue gas, the nature of this waste stream will change and modifications to the existing landfill are necessary. A normal landfill expansion project was placed in service in 2013 while final upgrades will be completed in 2015 to allow for the landfill to store byproducts associated with operation of the DSI system.

Q. WHAT ARE THE CAPITAL COSTS ASSOCIATED WITH THESE PROJECTS YOU DESCRIBE ABOVE?

A. The following Table 4 identifies the capital costs for the projects to be included in Kentucky Power's 2014 Environmental Compliance Plan:

Project	Plant	Description	In-Service Year	Project Cost (Kentucky Power Share)
9	Mitchell	Precipitator Modifications - Mitchell Plant Units 1 and 2	2007-2013	$28,065,512
10	Mitchell	Bottom Ash and Fly Ash Handling - Mitchell Plant Units 1 and 2	2008 & 2010	$25,273,426
11	Mitchell	Mercury Monitoring (MATS) - Mitchell Plant Units 1 and 2	2014	$1,991,740
12	Mitchell	Dry Fly Ash Handling Conversion - Mitchell Plant Units 1 and 2	2014	$60,114,772
13	Mitchell	Coal Combustion Waste Landfill - Mitchell Plant Units 1 and 2	2014 & 2015	$38,319,088
14	Mitchell	Electrostatic Precipitator Upgrade - Mitchell Plant Unit 2	2015	$1,574,056
				(Total Rockport Plant)
15	Rockport	Precipitator Modifications - Rockport Plant Units 1 & 2	2004-2009	$2,363,930
16	Rockport	Activated Carbon Injection (ACI) and Mercury Monitoring - Rockport Plant Units 1 & 2	2009-2010	$28,806,455
17	Rockport	Dry Sorbent Injection - Rockport Plant Units 1 and 2	2015	$141,568,091
18	Rockport	Coal Combustion Waste Landfill Upgrade To Accept Type 1 Ash	2013 & 2015	$22,057,551

Table 4: Capital Costs for Proposed 2014 Environmental Compliance Plan Projects

Q. ARE THE COSTS IDENTIFIED ABOVE ASSOCIATED WITH THESE PROJECTS REASONABLE?

A. Yes. It is my opinion that these projects are reasonable and cost effective means for Kentucky Power to comply with its environmental obligations.

Q. ARE THERE CONSUMABLES ASSOCIATED WITH THE PROJECTS IDENTIFIED FOR INCLUSION IN THE 2014 ENVIRONMENTAL COMPLIANCE PLAN?

A. Yes. As part of the ACI and DSI systems at Rockport Plant, brominated activated carbon and sodium bicarbonate, respectively, will be injected into the flue gas stream. The consumption of these variables is dependent upon the Plant's generating load.

Q. WHAT OTHER CONSUMABLES ARE ASSOCIATED WITH THOSE PROJECTS IDENTIFIED IN THE 2014 ENVIRONMENTAL COMPLIANCE PLAN?

A. In addition to the brominated activated carbon and sodium bicarbonate, those projects identified in the 2014 Environmental Compliance Plan require consumables such as urea, trona, limestone, polymer, and lime hydrate.

Solid urea is received on-site and is converted to ammonia before it is injected into the flue gas prior to passing through the SCR system at Mitchell Plant. The ammonia is necessary for the SCR technology to effectively reduce NO_X. This is the same manner in which urea has been used for years to operate the SCR at Big Sandy Unit 2.

Also at Mitchell Plant, limestone is crushed, mixed with water and made into a slurry that is used in the FGD system. The limestone used in the FGD system reacts with SO_2, removing it from the flue gas. Polymer and lime hydrate are used in treating the wastewater produced from the FGD system.

At the Mitchell Plant trona is also injected into the flue gas prior to the ESP to mitigate emissions of SO_3.

These consumables are necessary to operate the Mitchell Plant while also meeting the applicable environmental requirements.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	**)**	
A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	
Environmental Compliance Plan; (3) An Order	**)**	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

SHANNON R. LISTEBARGER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Shannon R. Listebarger, being duly sworn, deposes and says she is a Regulatory Analyst Sr. in Pricing and Analysis for American Electric Power Service Corporation and that she has personal knowledge of the set forth in the forgoing testimony for which she is identified as the witness and the information contained therein is true and correct to the best of his information, knowledge and belief.

Shannon R. Listebarger

Shannon R. Listebarger

STATE OF OHIO	)	
	)	Case No. 2014-00396
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Shannon R. Listebarger, this the 10th day of December, 2014.

Kelli N. Beuzard

Notary Public

My Commission Expires: 10/1/2019

NOTARIAL SEAL STATE OF OHIO

Kelli N. Beuzard
Notary Public, State of Ohio
My Commission Expires 10-01-2019

DIRECT TESTIMONY OF
SHANNON R. LISTEBARGER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
SHANNON R. LISTEBARGER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Shannon R. Listebarger. I am employed by American Electric Power Service Corporation (AEPSC) as a Regulatory Analyst in the Regulated Pricing and Analysis Department. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), the parent company of Kentucky Power Company. I will refer to Kentucky Power Company as KPCo and as “the Company”. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS A REGULATORY ANALYST IN THE REGULATORY PRICING AND ANALYSIS DEPARTMENT?

A. My responsibilities include preparing cost of service studies for regulatory filings and providing regulatory support and analysis for pricing matters associated with KPCo, and other AEP electric utility operating companies.

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

A. I received a Bachelor of Business Administration degree with a major in accounting from DeVry University in 2005, and a Master of Business Administration from Keller Graduate School of Management in 2007.

In 2001 I joined AEPSC as an Administrative Associate, a role I held for several years in various departments including Project Controls, Environmental Services and Corporate Development. From 2005 until 2010, I was an Accountant in the Corporate Accounting Department. In 2010 I transferred to Kentucky Power Company as a Regulatory Consultant working in the Regulatory Services Department. In 2013 I transferred to AEPSC to my current position of Regulatory Analyst in the Regulatory Pricing and Analysis Department.

III. PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my testimony is to sponsor Exhibit 1, the Kentucky Jurisdictional Cost of Service, which develops the Base rate revenue requirement that the Company is requesting in this filing.

IV. COST OF SERVICE STUDY OVERVIEW

Q. WHAT IS THE SOURCE OF THE DATA USED IN THE COMPANY'S JURISDICTIONAL COST OF SERVICE STUDY?

A. The Company follows the Uniform System of Accounts (USOA) as prescribed by FERC and adopted by this Commission. The USOA sets the guidelines for recording assets, liabilities, income and expenses into various accounts. The costs recorded in each FERC account are examined to verify compliance with these guidelines and may be adjusted in the Company's jurisdictional cost of service study to reflect the Commission's policies and known and measurable changes to the test year level of expenditures.

Q. HOW IS THE INFORMATION USED TO DETERMINE THE COST ALLOCATION TO KENTUCKY RETAIL CUSTOMERS?

A. The costs recorded by FERC account are per book amounts pertaining to electric utility operations of the Company for service supplied to all customers, both wholesale and retail. KPCO's retail revenue is approximately 99% of its total revenue; and its wholesale revenue, which includes sales to the cities of Olive Hill and Vanceburg, is approximately 1% of its total revenue. It is therefore, necessary to identify and segregate costs related to only Kentucky jurisdictional retail service.

Q. EXPLAIN HOW THE REVENUE REQUIREMENT IS DETERMINED FOR THE KENTUCKY RETAIL CUSTOMERS.

A. A three-step process is followed to assign and allocate costs to determine the total revenue requirement for the Companies retail customers. These steps include the functionalization of costs, the classification of costs and the allocation of costs.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.

A. Once the data is gathered, the costs are then separated by function. Typically, functions of an electric utility are:

1) Production and Purchased Power costs
2) Transmission costs
3) Distribution costs
4) Customer Service costs
5) Administrative and General (A&G) costs

Q. PLEASE DESCRIBE EACH OF THESE FUNCTIONS.

A. The production and purchased power function includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission function consists of the costs associated with the high voltage system utilized for the bulk transmission of power from generation sources to the load centers, and to and from interconnected utilities. The distribution function includes the radial distribution system that connects the transmission system and the ultimate retail customer. The customer service function encompasses the costs associated with providing meter reading, billing and collection, and customer information and services. The A&G function comprises of costs not directly assignable to other cost functions.

Q. PLEASE DESCRIBE THE CLASSIFICATION PROCESS.

A. The second step is to separate functionalized costs into classifications. Those classifications include 1) demand costs (costs associated with the kW demand imposed by the customer), 2) energy costs (costs that vary with the number of kilowatt hours used by the customer), 3) customer costs (costs that are directly related to the number of customers served) and 4) labor costs (costs that are directly related to payroll expenses associated with serving customers). The cost classifications used for the functions are as follows:

Function	Classification
Production and Purchased Power costs	Demand, Energy
Transmission costs	Demand
Distribution costs	Demand, Customer
Customer Service costs	Customer
A&G costs	Labor

Production plant costs, such as depreciation and return on investment, are considered to be demand-related costs. Most fuel and production operation and maintenance (O&M) expenses are energy-related because they vary with the quantity of energy produced. Transmission costs are demand-related because they are fixed and do not vary with energy usage. Generally, the distribution system costs are affected by either demand or by the number of customers served. Demand-related distribution costs will usually vary with the size of the load served, while customer-related distribution costs vary with the number of customers receiving the service. The classification process provides a basis on which to allocate different categories of costs (demand, energy or customer) to the utility's jurisdictions.

Q. PLEASE DESCRIBE THE ALLOCATION PROCESS.

A. The third and final step is to allocate functionalized and classified costs among the jurisdictions based on how the costs are incurred for each jurisdiction. The objective in this process is to determine a reasonable, appropriate and understandable method to assign costs. Some costs are directly assignable to a jurisdiction. Cost related to regulatory deferrals may be associated with a specific jurisdiction and may therefore be directly assigned to that jurisdiction. Most costs, however, are attributable to all of a utility's jurisdictions. These are joint costs and must be allocated to the jurisdictions by an allocation methodology that is based on the classification described above for that cost.

Q. ARE THE ALLOCATION METHODS EMPLOYED BY THE COMPANY CONSISTENT WITH THE PREVIOUSLY DISCUSSED COST OF SERVICE PRINCIPLES?

A. Yes. The allocation methodologies utilized in the Company's cost of service study were chosen after giving consideration to each of the principles discussed previously. The results of the cost of service study can be relied upon to determine the appropriate revenue requirement for the Company's Kentucky retail jurisdiction.

Q. ARE YOU RESPONSIBLE FOR THE KENTUCKY JURISDICTIONAL METHODOLOGY USED IN THE PREPARATION OF THIS CASE?

A. Yes. The allocation methodology and the allocation factors used to calculate the Kentucky retail jurisdictional amounts were developed by me. The methodology used in this case is the same methodology used in the Company's last several rate cases.

V. ALLOCATIONS

Q. PLEASE DESCRIBE HOW THE ENERGY ALLOCATION FACTOR (EAF) WAS DETERMINED.

A. The retail customers test year sales of energy were accumulated and adjusted to the generation level by applying the appropriate transmission and distribution loss factors to obtain KWH of test period sales of energy to retail customers. The result was then divided by the net total Company energy requirements at the generation level to obtain the retail energy allocation factor.

Q. PLEASE DESCRIBE HOW THE DEMAND ALLOCATION FACTOR (PDAF) WAS DETERMINED.

A. The Company serves retail customers under the jurisdiction of the Kentucky Public Service Commission and two wholesale customers that are regulated by FERC jurisdiction. One basis for allocating the elements of the cost of property between retail and wholesale customers is the respective contribution by each of the two classes to the Company's peak demand. The PDAF reflects the coincident demand of the Company's retail customers at the time of Kentucky Power's monthly peak demand; in other words, it represents the kilowatt contribution of those customers to the Company's monthly peak demand. The production demand allocation factor was calculated by dividing the average of the twelve monthly retail class coincident demands, adjusted for losses to the generation levels, by the average of the twelve monthly total Company internal peak demands. The transmission and sub-transmission demand allocation factors are the same as the production demand allocation factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF KPCO'S ELECTRIC PLANT IN SERVICE.

A. Electric Plant in Service was separated into different plant categories by function and then allocated accordingly. KPCo's Production plant was allocated to the two jurisdictions using the production demand allocation factor (PDAF). Transmission plant was allocated using the transmission demand allocation factor (TDAF). Distribution plant was allocated using the gross plant distribution factor (GP-DIST). General and Intangible plant were allocated using gross plant production, transmission and distribution factor (GP-PTD).

Q. PLEASE DESCRIBE THE ALLOCATION OF KPCO'S ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION.

A. KPCo's Accumulated Provision for Depreciation and Amortization were functionalized and classified in a fashion similar to KPCo's Electric Plant in Service. Production, transmission and distribution accumulated depreciation was allocated consistent with the allocation of the associated plant. General and Intangible plant accumulated depreciation was allocated by GP-PTD factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF KPCO'S OTHER RATE BASE COMPONENTS.

A. Electric Plant held for Future Use, Construction Work in Progress and Allowance for Funds Used during Construction were booked by functional group and then allocated using the associated plant factors. The Carrs Site, which represents the majority of the production-related Plant Held for Future Use, is a ratemaking elimination and is removed from Plant Held for Future Use prior to the allocation process.

Fuel and Allowance Inventory were allocated using the energy allocation factor (EAF). Materials and Supplies were separated into functional groups and allocated by associated plant factors accordingly. Materials and Supplies other components, such as Lime, Limestone, Urea and Urea In-Transit are allocated using the EAF. Prepayments were allocated using the gross plant total allocation factor (GP-TOT).

The Cash Working Capital component is calculated by using the standard formula of one-eighth of Total Company O&M expenses. This equals one and one half months of the Company's O&M expenses.

Accumulated Deferred Investment Tax Credit amounts were provided by Company Witness Bartsch. Customer Advances and Customer Deposits are a result of the Kentucky jurisdiction retail operations and therefore 100% of these amounts are allocated to the Kentucky retail jurisdiction.

Q. PLEASE DESCRIBE THE ALLOCATION OF KPCO'S OPERATING REVENUES.

A. Sales revenue was directly assigned to each jurisdiction where possible. Demand-related system sales revenue was allocated based on the PDAF. Energy-related system sales revenue was allocated on the EAF.

Forfeited Discounts and miscellaneous service revenues were a result of the Kentucky jurisdiction retail operations and therefore directly assigned 100% to Kentucky retail jurisdiction.

Rent from electric property and other electric revenue were allocated to jurisdictions based on the corresponding functional allocator. DSM revenues and various transmission agreement revenues were removed to derive the total electric utility other operating revenues.

Q. PLEASE DESCRIBE THE ALLOCATION OF KPCO'S OPERATING AND MAINTENANCE EXPENSES.

A. Production-related Operation and Maintenance (O&M) expenses were classified as either demand or energy-related. The demand component was allocated using the PDAF and the energy component was allocated using the EAF.

Transmission-related O&M was allocated based on the gross plant transmission (GP-TRANS) allocation factor or directly assigned as applicable.

Distribution-related O&M was allocated based on the gross plant distribution (GP-DIST) allocation factor or directly assigned as applicable.

Customer Accounts, Customer Information and Customer Service expense were classified as customer-related and allocated on the total number of customers.

Administrative and General (A&G) Regulatory and Sales O&M expense was specifically assigned to retail. Non-regulatory Administrative and General

(A&G) expenses have been distributed to the other functions in proportion to related payroll expenses and then allocated to the Kentucky retail jurisdiction.

Q. PLEASE DESCRIBE THE ALLOCATION OF KPCO'S DEPRECIATION AND AMORTIZATION EXPENSE.

A. Depreciation and Amortization were booked by functional group then allocated using the associated plant factors.

Q. PLEASE EXPLAIN HOW KPCO'S TAXES OTHER THAN FEDERAL AND STATE INCOME TAXES WERE ALLOCATED.

A. Taxes Other than Income Taxes were classified as relating to payroll, property, revenue, demand or energy and allocated accordingly or directly assigned. Payroll taxes are related to labor and allocated on the payroll allocation factor (OML). Property taxes were allocated using the GP-TOT allocation factor.

Q. PLEASE EXPLAIN HOW KPCO'S FEDERAL AND STATE INCOME TAXES WERE ALLOCATED.

A. For details on Federal and State Income Taxes, please see Company witness Bartsch testimony and supporting tax schedules.

Q. PLEASE EXPLAIN HOW ADJUSTMENTS FOR KPCO WERE INCORPORATED INTO SECTION V.

A. Kentucky retail adjustments were provided to me by way of individual worksheets, which were compiled and prepared by various Company witnesses based on their expertise. I added the Kentucky retail adjustments to the Kentucky retail per books cost of service amounts to arrive at the going-level Kentucky jurisdictional cost of service.

Q. PLEASE EXPLAIN THE DIFFERENCES IN PRESENTATION, FROM PAST FILINGS, IN THE FORMAT OF THE COMPANY'S JURISDICTIONAL COST OF SERVICE STUDY.

A. The differences in presentation in the Company's jurisdictional cost of service study pertain mainly to departures from the Company's previous filing format of Section V, Schedule 5 through Schedule 17.

Q. PLEASE EXPLAIN THE REASON FOR THE DEPARTURE FROM THE FORMAT USED IN PAST JURISDICTIONAL COST OF SERVICE STUDIES OF THE COMPANY.

A. The new format provides greater detail by FERC account, which should facilitate the review of the Company's Cost of Service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	)	
A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

DIRECT TESTIMONY OF

MCCOY, MCMANUS, PHILLIPS, REITTER

ON BEHALF OF KENTUCKY POWER COMPANY

SECTION III

VOLUME 2 OF 4

December 23, 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	**)))))))**	**Case No. 2014-00396**

DIRECT TESTIMONY OF

HUGH E. MCCOY

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Hugh E. McCoy, being duly sworn, deposes and says he is the Director, Accounting Policy and Research for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Hugh E McCoy

Hugh E. McCoy

STATE OF OHIO	)	
	)	Case No. 2014-00396
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Hugh E. McCoy, this the 10th day of December, 2014.

Kathy L M[illegible]

Notary Public

My Commission Expires: August 18, 2017

DIRECT TESTIMONY OF
HUGH E. MCCOY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
HUGH E. MCCOY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Hugh E. McCoy. My position is Director of Accounting Policy and Research for the American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Kentucky Power Company (Kentucky Power or the Company). AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's ten electric operating companies, including Kentucky Power. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated magna cum laude from West Virginia University in 1977, with a Bachelor of Science in Business Administration degree in Accounting.

From 1977 to 1981, I was employed by Peat, Marwick, Mitchell and Co., where I was promoted to Audit Supervising Senior. I have been a Certified Public Accountant since 1979 and a member of the American Institute of Certified Public Accountants since 1980.

Since 1981, I have been employed by AEPSC. I served from 1981 to early 1998 in Accounting Policy and Research, initially as a Treasury Staff Accountant and beginning in 1989 as a Senior Treasury Staff Accountant. In 1998, I was promoted to Manager of Utility Ledgers for AEP's operating companies in Ohio. In 2000, I was promoted to Assistant Controller of Non-Regulated Accounting. Following two years in that position and a one-year rotational assignment to Corporate Finance, I returned to Accounting Policy and Research in my current position in 2003 and assumed plant accounting policy responsibilities in 2010.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF ACCOUNTING POLICY AND RESEARCH?

A. I am responsible for performing accounting research, recommending accounting policy and procedures, reporting on the financial effects of potential transactions, and developing accounting instructions for certain non-routine transactions and new accounting rules. I serve as AEP's primary internal advisor with regard to issues surrounding the accounting for employee benefits, including pensions and postretirement benefits. I also have supervisory responsibility for plant accounting policy matters.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS OR OTHER UTILITY REGULATORY COMMISSIONS?

A. Yes, I have previously testified on retiree benefits accounting before this Commission, the state utility regulatory commissions of Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia, and the Federal Energy Regulatory Commission.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my direct testimony is to address for the Company the amount of pension cost and postretirement benefit cost that the Company has included for ratemaking purposes. In addition, I will support the inclusion in rate base of the additional cash investment in the pension trust fund recorded as a prepaid pension asset in accordance with generally accepted accounting principles. This additional pension funding benefits customers through substantially reduced pension cost.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am sponsoring Exhibits HEM-1 through HEM-3. Exhibit HEM-1 is my schedule that compiles pension and postretirement benefit costs from the 2013 and 2014 actuarial reports and computes pension and postretirement benefit costs for the twelve months ended September 30, 2014. Exhibit HEM-2 consists of the 2014 pension and postretirement benefit actuarial reports prepared by the Company's independent actuary, Towers Watson. Exhibit HEM-3 is my schedule of the effect of additional pension contributions recorded as a prepaid pension asset in reducing pension cost.

IV. PENSION COST

Q. PLEASE DESCRIBE THE COMPANY'S PENSION PLANS.

A. The employees of the Company participate in the AEP defined benefit pension plan ("AEP Plan"). This plan is subject to the Employee Retirement Income Security Act of 1974 (ERISA) and various regulations under the Internal Revenue Code

(IRC). The AEP Plan provides benefits based on either a cash balance design or, for employees who were plan participants on December 31, 2000, under a grandfathered design. The cash balance design provides participants with a notional account that provides annual credits based on compensation, age, and years of service, plus annual interest on the account balance. The grandfathered design provides a final average pay benefit that continued to grow for a ten-year transition period ending December 31, 2010. At retirement, grandfathered participants may choose either the grandfathered benefit or the cash balance benefit.

Q. HOW IS PENSION COST DETERMINED?

A. The Company's pension cost is computed as part of an annual actuarial valuation performed by Towers Watson, the Company's independent actuary, in accordance with generally accepted accounting principles under Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. (FAS) 87, *Employers' Accounting for Pensions* (also known as FASB ASC 715-30).

As required by FAS 87, ERISA, and actuary professional standards, Towers Watson performs the valuation using reasonable actuarial methods and assumptions, which are disclosed in Appendix A - Statement of Actuarial Assumptions and Methods – to the actuarial reports included in Exhibit HEM-2. These actuarial assumptions, which are consistent with the requirements of FAS 87, are discussed in more detail later in this testimony. All of the underlying actual economic and demographic data included in the April 2014 actuarial reports was complete, known and measurable as of December 31, 2013.

Although Kentucky Power participates along with other affiliates in the AEP Plan, the Company's pension benefit cost is computed directly based on the specific demographics of the Company's actual employees and retirees and based on the Company's actual trust fund contributions and benefit payments. Accordingly, an assignment of a portion of total cost of the AEP Plan to the Company is not necessary. This long-standing method of determining the Company's pension cost is reasonable, fair, and equitable and results in no cross-subsidization of cost between the Company and its affiliates.

Q. WHAT ARE THE COMPONENTS OF PENSION COST UNDER FAS 87?

A. FAS 87 pension cost includes the following components:

- Service cost, or the present value of benefits earned by employees for the current year.
- Interest cost on the projected benefit obligation (PBO). Interest accrues each year because the PBO is computed on a discounted, or present value, basis.
- Investment return expected on trust fund assets.
- Amortization of deferred costs, including:
  - Actuarial gains and losses, or differences between actual and projected economic and demographic experience.
  - Prior service cost, or fluctuations in the PBO caused by retroactive plan design changes.
  - Transition asset or obligation, or the catch-up adjustment upon initial application of FAS 87.

Q. PLEASE DESCRIBE THE ASSUMPTIONS USED IN THE COMPANY'S FAS 87 ACTUARIAL REPORT.

A. FAS 87 actuarial assumptions fall into two categories: demographic assumptions and economic assumptions. These assumptions are annually reviewed with the independent actuary and adjusted as appropriate to ensure that they are reasonable, both individually and in aggregate, and that they accurately reflect expected future experience of the plan. These assumptions also apply to postretirement benefit cost under FASB FAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (also known as FASB ASC 715-60).

Q. PLEASE DESCRIBE THE DEMOGRAPHIC ASSUMPTIONS USED IN THE ACTUARIAL STUDIES AND HOW THEY WERE DEVELOPED.

A. The demographic assumptions used to develop pension and postretirement benefit liabilities include mortality rates, employee withdrawal rates, expected retirement age, and assumptions regarding marital status and spouse's age. The assumptions regarding expected mortality and marital status are considered standard and are used by the majority of large companies for their FAS 87 and FAS 106 actuarial valuations. The employee turnover and retirement assumptions are based on studies of prior AEP demographic experience.

Q. PLEASE DESCRIBE THE ECONOMIC ASSUMPTIONS AND HOW THEY WERE DEVELOPED.

A. The economic assumptions used to develop pension and postretirement benefit liabilities include discount rate selection, an assumption regarding the expected long-term rate of return on plan assets, and estimates of expected future growth of employee salaries. The discount rate is used to adjust for the time value of money, as most of each plan's expected benefit payments will not be paid for many years. In accordance with FAS 87 and FAS 106, the discount rate is chosen as of the Company's December 31 annual measurement date to be in line with high-quality corporate bond yields. The rate chosen is based on the matching of high quality corporate bond spot rates to the annual projected benefit payments expected for the plans.

The long-term rate of return on assets is chosen based on a study of the mix of the assets funding the plan and the expected rate of return on each asset category. Lastly, the salary growth rate takes into account expected changes in compensation levels, including cost-of-living adjustments, merit increases, and promotions. This assumption also is based on prior AEP experience. All three of these economic assumptions are the same or similar for the FAS 87 valuation and the FAS 106 valuation, except that the FAS 106 expected return on assets assumption takes into account the different effect of income taxes on postretirement benefit trust funds.

Q. DO THE ACTUARIAL ASSUMPTIONS AND METHODS DISCUSSED ABOVE PROVIDE A REASONABLE BASIS FOR DETERMINING THE LEVEL OF PENSION COST TO BE INCLUDED IN COST OF SERVICE?

A. Yes. The demographic and economic actuarial assumptions, as well as the methods used for the pension valuation, are reasonable both individually and in the aggregate. They are consistent with the requirements of generally accepted accounting principles as set forth in FAS 87 and actuarial industry standards and they have been consistently applied from year to year.

Q. WHAT AMOUNT OF PENSION COST IS REFLECTED IN THE COMPANY'S FILING?

A. Exhibit HEM-1 shows the amount of the Company's actual FAS 87 pension cost for the 2013 and 2014 calendar years from each year's actuarial report. Exhibit HEM-1 also computes the Company's total pension cost of $4,249,110 for the twelve months ended September 2014 test year. However, consistent with prior filings, the Company's filing includes the calendar year 2014 total pension cost of $4,311,543 since this updated amount is more representative of the cost to be incurred during the period that rates resulting from this proceeding will be in effect. The Transmission and Distribution pension cost as shown on Exhibit HEM-1 is $2,637,992 for the twelve months ended September 30, 2014 and $2,567,458 for the calendar year 2014. The Generation portion of pension cost is included in adjustments related to recovery of Big Sandy Plant and Mitchell Plant costs supported by Company Witness Yoder.

Q. WHY IS TRANSMISSION AND DISTRIBUTION PENSION COST LOWER FOR THE CALENDAR YEAR 2014 THAN FOR THE TWELVE MONTHS ENDED SEPTEMBER 2014 TEST YEAR?

A. Transmission and Distribution pension cost for the Company decreased in calendar year 2014 mainly because of favorable changes in both investment return and interest rates.

Q. PLEASE EXPLAIN THE BASIS FOR THE BREAKOUT ON EXHIBIT HEM-1 OF QUALIFIED AND NON-QUALIFIED COSTS.

A. The schedule on Exhibit HEM-1 accumulates separate columns for the amount of qualified cost and for the amount of non-qualified cost (also know as excess, supplemental, or SERP (Supplemental Employee Retirement Plan) cost), since a separate actuarial report is prepared for each. Actuarial reports typically are prepared separately for the amount of pension benefits that may be included in a qualified pension trust fund under ERISA versus the excess or supplemental amount related to benefits beyond the statutory qualified plan limits on benefits and pay. This helps to avoid confusion about funding of qualified plans and provides the segregated information required by accounting and reporting rules. The distinction between qualified and non-qualified amounts has no bearing on the amount of costs that are reasonable and necessary to meet the Company's requirements to provide reasonable and adequate pensions for its employees. The qualified amount is simply the portion that is subject to ERISA requirements, protections and income tax incentives. The supplemental amount is the portion of an employee's pension benefit that exceeds the qualified plan limits on benefits and pay.

Q. DOES THE SERP PROVIDE SEPARATE AND ADDITIONAL BENEFITS TO THE COMPANY'S EXECUTIVES?

A. No. The same pension benefit formula applies to all employees regardless of pay level. The supplemental plan simply replaces the portion of pension benefits that otherwise would be lost under the qualified plan limits. It is reasonable and necessary to provide the supplemental pension plan to replace the portion of pension benefits that otherwise would be lost so that the Company can attract, retain, and motivate competent and qualified leaders.

V. POSTRETIREMENT BENEFIT COST

Q. PLEASE DESCRIBE THE COMPANY'S POSTRETIREMENT BENEFIT PLAN.

A. The employees of the Company also participate in AEP's Non-UMWA Postretirement Benefit Plan, which provides medical and life insurance benefits to AEP employees who are not members of the United Mine Workers of America. AEP provides postretirement benefits, including subsidized medical and dental coverage, prescription drug coverage, and life insurance benefits, to employees who retire directly from an AEP System company after attaining at least age 55 with at least ten years of service.

Q. HOW IS POSTRETIREMENT BENEFIT COST DETERMINED?

A. The Company's postretirement benefit cost is computed as part of an annual actuarial valuation performed by Towers Watson, the Company's independent actuary, in accordance with generally accepted accounting principles under the requirements of FAS 106. As required by FAS 106 and actuary industry standards, Towers Watson performs the valuation using reasonable actuarial methods and assumptions, which are disclosed under Appendix A – Statement of Actuarial Assumptions and Methods in the actuarial report included in Exhibit HEM-2. These actuarial assumptions, which are consistent with the requirements of FAS 106, are discussed in more detail later in this testimony.

As is the case with the calculation of pension cost that I discussed above, the Company's postretirement benefit cost is computed directly based on the specific demographics of the Company's actual employees and retirees and based on the Company's actual trust fund contributions and benefit payments. This method of determining the Company's postretirement benefit cost is reasonable, fair and equitable and results in no cross-subsidization of cost between the Company and its affiliates.

The 2014 actuarial report was completed in April 2014. All of the underlying actual economic and demographic data included in the 2014 actuarial report was complete, known and measurable as of December 31, 2013.

Q. WHAT ARE THE COMPONENTS OF POSTRETIREMENT BENEFIT COST?

A. FAS 106 postretirement benefit cost includes the same components as FAS 87 pension cost already discussed above, those being service cost, interest cost, investment return, and amortizations. Except for minor differences necessitated by the slightly different nature of pension benefits and postretirement benefits, the requirements of FAS 106 are very similar to those of FAS 87.

FAS 106 requires that employers such as the Company record the cost of postretirement benefits on an accrual basis during the working lives of employees. Under FAS 106, employers are required to accrue during employees' years of service a liability for the present value of their future benefits, so that an employer will have accrued the present value of the entire benefit cost by the employee's retirement date. The FASB based the rule on its decision that postretirement benefits are a form of deferred compensation that should be recorded on an accrual basis as the benefits are earned, much like pensions.

Q. PLEASE DESCRIBE THE ASSUMPTIONS USED IN THE FAS 106 ACTUARIAL REPORT.

A. FAS 106 actuarial assumptions fall into three categories: demographic assumptions, economic assumptions, and health care cost assumptions. These assumptions are reviewed with the independent actuary and adjusted annually to ensure that they are reasonable, both individually and in aggregate, and that they accurately reflect expected future experience of the plan. Demographic assumptions and economic assumptions also apply to pension cost under FAS 87.

Q. WHAT DEMOGRAPHIC AND ECONOMIC ASSUMPTIONS WERE USED IN THE POSTRETIREMENT BENEFIT ACTUARIAL STUDY AND HOW WERE THEY DEVELOPED?

A. The demographic and economic assumptions used to develop pension liabilities also apply to the assumptions used to develop postretirement benefit liabilities.

Q. PLEASE DESCRIBE HOW THE HEALTH CARE COST ASSUMPTIONS USED IN THE FAS 106 STUDY WERE DEVELOPED.

A. The health care cost trend rate for each future year is the expected annual rate of increase in the per capita health care charges submitted for reimbursement under the plan, before the effect of deductibles and co-payments. These rates are developed based on an analysis of the plan's design and experience, as well as medical cost trend rate information available from the insurance industry and published surveys. These data take into account all appropriate components of medical inflation that might affect retiree medical costs, including pure costs of services, utilization, cost shifting, technological advances, growth, and increase in malpractice insurance costs. The rates that are developed are then compared to the rates being used by other large organizations to make sure they are in line with assumptions being used for plans with similar benefits.

Q. DO THE ACTUARIAL ASSUMPTIONS AND METHODS DISCUSSED ABOVE PROVIDE A REASONABLE BASIS FOR DETERMINING THE LEVEL OF POSTRETIREMENT BENEFIT COST TO BE INCLUDED IN COST OF SERVICE?

A. Yes. The actuarial assumptions and methods used for the postretirement benefits valuation are reasonable both individually and in the aggregate. They are consistent with the requirements of generally accepted accounting principles as set forth in FAS 106 and actuarial industry standards.

Q. WHAT AMOUNT OF POSTRETIREMENT BENEFIT COST IS THE COMPANY REQUESTING?

A. Exhibit HEM-1 shows the amount of the Company's actual FAS 106 postretirement benefit cost for the 2013 and 2014 calendar years from each year's actuarial report. Exhibit HEM-1 also computes the Company's postretirement benefit cost of $(2,346,792) for the twelve months ended September 2014 test year. However, the Company's filing includes the calendar year 2014 postretirement benefit cost of $(2,793,315) since this updated amount is more representative of the cost to be incurred during the period that rates resulting from this proceeding will be in effect. The Transmission and Distribution postretirement benefit cost as shown on Exhibit HEM-1 is $(1,462,835) for the twelve months ended September 30, 2014 and $(1,714,439) for the calendar year 2014. The Generation portion of postretirement benefit cost is included in adjustments related to recovery of Big Sandy Plant and Mitchell Plant costs supported by Company Witness Yoder.

Q. WHY IS POSTRETIREMENT BENEFIT COST A NEGATIVE AMOUNT?

A. Postretirement benefit cost for the Company turned negative (a credit to expense) in 2013 mainly because of a plan amendment effective for retirements after 2012 that caps the Company's contribution to retiree medical coverage, thereby reducing the Company's exposure to future medical cost inflation. The resulting decline in the plan benefit obligation creates an actuarial gain that under FAS 106 is amortized to postretirement benefit cost over about 12 years beginning in 2013.

Q. WHY IS THE TRANSMISSION AND DISTRIBUTION POSTRETIREMENT BENEFIT CREDIT OR NEGATIVE COST HIGHER FOR THE CALENDAR YEAR 2014 THAN FOR THE TWELVE MONTHS ENDED SEPTEMBER 2014 TEST YEAR?

A. The amount of Transmission and Distribution postretirement benefit credit or negative cost for the Company increased in 2014 mainly because of favorable investment return and refined actuarial assumptions.

VI. RATE BASE TREATMENT OF THE PREPAID PENSION ASSET

Q. PLEASE EXPLAIN THE AMOUNT OF ADDITIONAL PENSION FUNDING THAT SHOULD BE INCLUDED IN RATE BASE.

A. In accordance with the provisions of generally accepted accounting principles under FAS 87, the Company has recorded as a prepaid pension asset additional cash pension contributions in excess of FAS 87 pension cost in the amount of $53,709,968 as of September 30, 2014. This total prepaid pension asset balance is separate from the related accumulated deferred federal income taxes that serve to reduce the combined rate base effect. As shown on EXHIBIT HEM-3, this prepaid pension asset includes substantial contributions totaling approximately $75 million from 2005 through 2014.

Q. HAS THE COMPANY BROUGHT THE ADDITIONAL PENSION CONTRIBUTIONS BEFORE THE COMISSION IN PRIOR CASES?

A. Yes, in Case No. 2005-00341, Case No. 2009-00459, and Case No. 2013-00197.

Q. WHY DID THE COMPANY MAKE THESE ADDITIONAL PENSION CONTRIBUTIONS?

A. The 2005 additional cash contributions eliminated the funding shortfall that had developed between pension plan assets and the FAS 87 benefit obligation. As a result of these additional contributions, the Company's qualified pension benefit obligation was fully funded at the end of 2005 and through 2007. Following the market downturn in 2008, additional pension contributions were required in 2010, 2011, 2012, and 2014.

Q. IS THIS PREPAID PENSION BALANCE THAT THE COMPANY PROPOSES TO INCLUDE IN RATE BASE ENTIRELY SUPPORTED BY CASH CONTRIBUTIONS?

A. Yes, the prepaid pension amount to be included in rate base is entirely supported by actual cash contributions in excess of pension cost. Including this amount in rate base will allow ratemaking recognition of the Company’s cost of funds on the additional cash contributions. Not included in the Company’s request are non-cash accrual adjustments made under FAS 158, *Employers’ Accounting for Defined*

Benefit Pension and Other Postretirement Plans (also known as FASB ASC 715-20), since such adjustments have no effect on the amount of the Company's cash pension investment or its FAS 87 pension cost.

Q. DOES ANY PORTION OF THE PREPAID PENSION ASSET SERVE TO PRE-FUND THE COMPANY'S PENSION OBLIGATIONS IN ADVANCE?

A. No. These additional contributions were made to address substantial underfunding that would have continued to exist if the contributions had not been made. They do not relate to anticipating or pre-funding future obligations but rather were made to help catch-up funding to the current accumulated benefit obligation. With these additional contributions, the Company's qualified pension plan was about 100 percent funded in terms of the FAS 87 benefit obligation at December 31, 2013. Without the additional pension contributions that are recorded as a prepaid pension asset, the qualified pension would be only about 69 percent funded, a dangerously low level. The additional pension contributions have been prudently incurred by the Company to provide service to its customers, are necessary for the provision of service, and constitute property that is used and useful in providing public service.

Q. PLEASE EXPLAIN WHY THE ADDITIONAL PENSION CONTRIBUTIONS WERE NECESSARY.

A. As explained above, pension cost included in cost of service for ratemaking purposes is based on generally accepted accounted principles as set forth in FAS 87. However, pension contributions are based on separate ERISA requirements, so the amount of pension cost and the amount of pension cash contribution can often vary. FAS 87 requires that this difference be recorded on the balance sheet as a prepayment if contributions exceed cost or as a liability if cost exceeds contributions.

The Company's pension funding shortfall under FAS 87 grew substantially over the period 2000 through 2003 because of a combination of factors that increased significantly the difference between the accumulated pension benefit obligation and the pension fund assets. The decline in value of the pension fund assets and the increase in pension obligations caused the Company’s previously well-funded pension plan to become significantly underfunded, as was the case for other pension plans in the industry.

By 2005, the amount of underfunding had reached the point that it was neither prudent nor reasonable for the Company to rely on the shortfall reversing over time through normal market activity and ERISA-required cash contributions. Moreover, allowing the disparity between pension assets and the accumulated pension obligation to remain at the then current level, or risking possible further growth in the disparity, would have entailed making substantially increased required pension funding contributions in future years, since the additional investment income that results from contributing earlier rather than later reduces the total amount that needs to be contributed over time. Accordingly, the Company needed to take action by making additional contributions to bring the pension fund assets and the accumulated benefit obligation into alignment. Under these circumstances, the making of the additional contributions was clearly prudent and necessary.

The market decline of 2008 and the decline in interest rates in 2009 through 2012 again caused the difference between the benefit obligation and the pension fund assets to grow. As a result, the Company made substantial additional contributions in 2010, 2011 and 2012. These contributions were prudently made to reduce the funding shortfall and to bring the pension assets closer into alignment with the benefit obligation.

Q. DO CUSTOMERS OF THE COMPANY BENEFIT FROM THE ADDITIONAL FUNDING OF THE PENSION PLAN?

A. Yes, customers benefit from the investment earnings on the additional fund assets. This has the effect of reducing future pension cost under generally accepted accounting principles in an amount that grows over time through compounding. As computed on Exhibit HEM-3, the additional pension contributions recorded as a prepaid pension asset reduced by approximately $4.2 million the 2014 pension cost that the Company would have had to recover from customers. In other words, had the Company not made the additional pension contributions, the Company's total amount of 2014 pension cost would have been nearly $8.5 million instead of approximately $4.3 million.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Pension and Postretirement Benefit (OPEB) Cost in Account 926
Kentucky Power Company

	FAS 87 Cost			FAS 106
	Qualified	SERP	Total Pension	OPEB Cost
Calendar Year 2013 Actual per Actuarial Report				
Distribution	2,532,324	3,895	2,536,219	(600,974)
Transmission	313,374	0	313,374	(107,047)
Total Wires	**2,845,698**	**3,895**	**2,849,593**	**(708,021)**
Generation (Big Sandy)	1,212,219	0	1,212,219	(299,204)
50% of Mitchell	0	0	0	0
Total Generation	1,212,219	0	1,212,219	(299,204)
Total Company	4,057,917	3,895	4,061,812	(1,007,225)
Calendar Year 2014 Actual per Actuarial Report				
Distribution	2,293,613	239	2,293,852	(1,495,454)
Transmission	273,606	0	273,606	(218,985)
Total Wires	**2,567,219**	**239**	**2,567,458**	**(1,714,439)**
Generation (Big Sandy)	1,111,950	0	1,111,950	(856,233)
50% of Mitchell	632,135	0	632,135	(222,643)
Total Generation	1,744,085	0	1,744,085	(1,078,876)
Total Company	4,311,304	239	4,311,543	(2,793,315)
12 Months Ended September 2014 Computed from Above				
Distribution	2,353,291	1,153	2,354,444	(1,271,834)
Transmission	283,548	0	283,548	(191,001)
Total Wires	**2,636,839**	**1,153**	**2,637,992**	**(1,462,835)**
Generation (Big Sandy)	1,137,017	0	1,137,017	(716,976)
50% of Mitchell	474,101	0	474,101	(166,982)
Total Generation	1,611,118	0	1,611,118	(883,958)
Total Company	4,247,957	1,153	4,249,110	(2,346,792)
Calendar Year 2014 Versus 12 Months Ended September 2014				
Distribution	(59,678)	(914)	(60,592)	(223,620)
Transmission	(9,942)	0	(9,942)	(27,985)
Total Wires	**(69,620)**	**(914)**	**(70,534)**	**(251,605)**
Generation (Big Sandy)	(25,067)	0	(25,067)	(139,257)
50% of Mitchell	158,034	0	158,034	(55,661)
Total Generation	132,966	0	132,966	(194,918)
Total Company	63,347	(914)	62,433	(446,522)

Pension and Postretirement Benefit (OPEB) Cost in Account 926
Kentucky Power Company

	FAS 87 Cost			FAS 106
	Qualified	SERP	Total Pension	OPEB Cost
Calendar Year 2013 Actual per Actuarial Report	4,057,917	3,895	4,061,812	(1,007,225)
Calendar Year 2014 Actual per Actuarial Report	5,190,316	239	5,190,555	(3,040,335)
12 Months Ended September 2014 Computed from Above	4,907,216	1,153	4,908,369	(2,532,058)
Calendar Year 2014 Versus 12 Months Ended September 2014	283,100	(914)	282,186	(508,278)

Exhibit HEM-2

2014 Actuarial Reports

Exhibit HEM-2 includes the following 2014 AEP Actuarial Reports:

- Exhibit HEM-2A Qualified Pension
- Exhibit HEM-2B Supplemental Pension
- Exhibit HEM-2C Non-UMWA Postretirement

American Electric Power

American Electric Power System Retirement Plan

Actuarial Valuation Report

Pension Cost for Fiscal Year Beginning January 1, 2014 under US GAAP

Employer Contributions for Plan Year Beginning January 1, 2014

April 2014

TOWERS WATSON

Table of Contents

This page is intentionally blank

Purposes of valuation

American Electric Power Co. (the Company) retained Towers Watson Delaware Inc. ("Towers Watson"), to perform an actuarial valuation of the American Electric Power System Retirement Plan for the purpose of determining the following:

1. The minimum required contribution in accordance with ERISA and the Internal Revenue Code (IRC) for the plan year beginning January 1, 2014.

2. The estimated maximum tax-deductible contribution for the tax year in which the 2014 plan year ends in accordance with ERISA as allowed by the IRC. The maximum tax-deductible contribution should be finalized in consultation with the Company's tax advisor.

3. Plan accounting information in accordance with FASB Accounting Standards Codification Topic 960 (ASC 960).

4. Determination of the Funding Target Attainment Percentage (FTAP) under IRC §430(d)(2), as reported in the Annual Funding Notice required under ERISA 101(f).

5. The value of benefit obligations as of January 1, 2014 and American Electric Power Co.'s pension cost for fiscal year ending December 31, 2014 in accordance with FASB Accounting Standards Codification Topic 715 (ASC 715-30).

6. As requested by American Electric Power Co., a "specific certification" of the Adjusted Funding Target Attainment Percentage (AFTAP) for the American Electric Power System Retirement Plan under IRC §436 for the plan year beginning January 1, 2014. Please see Appendix C for additional information. Note that the AFTAP certification included herein may be superseded by a subsequent AFTAP certification for the American Electric Power System Retirement Plan for the plan year beginning January 1, 2014.

Limitations

This valuation has been conducted for the purposes described above and may not be suitable for any other purpose. In particular, please note the following:

1. This report does not determine the plan's liquidity shortfall requirements (if any) under IRC §430(j)(4). If applicable, we will determine such requirements separately as requested by the Company.

2. This report does not determine liabilities on a plan termination basis, for which a separate extensive analysis would be required.

3. The cost method for the minimum required contribution is established under IRC §430 and may not in all circumstances produce adequate assets to pay benefits under all optional forms of payment available under the plan when benefit payments are due.

4. This valuation reflects our understanding of the relevant provisions of the Pension Protection Act of 2006 (PPA); the Worker, Retiree and Employer Recovery Act of 2008 (WRERA); the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010 (PRA), and the Moving Ahead for Progress in the 21st Century Act (MAP-21). The IRS has yet to issue

final guidance with respect to certain aspects of these laws. It is possible that future guidance may conflict with our understanding of these laws based on currently available guidance and could therefore affect results shown in this report.

Section 1: Summary of results

Summary of valuation results

All monetary amounts shown in US Dollars

Plan Year Beginning	January 1, 2014	January 1, 2013
Funding		
Market value of assets with discounted receivable contributions	4,726,059,114	4,704,119,951
Actuarial value of assets	4,653,384,245	4,699,409,537
Funding balances	660,963,451	668,470,627
Funding target	4,221,975,836	4,024,284,946
Target normal cost	67,364,098	61,416,651
Funding shortfall (surplus)	229,555,042	(6,653,964)
Funding target attainment percentage (FTAP)	94.56%	100.16%
Minimum required contribution		
Prior to application of funding balances	67,364,098	54,762,687
Net of available funding balances	0	0
Effective interest rate	5.66%	6.24%
U.S. GAAP Accounting (ASC 715) as of Measurement Date	**January 1, 2014**	**January 1, 2013**
Projected benefit obligation (PBO)	4,741,966,540	5,158,918,282
Fair value of assets (without receivable contributions)	4,726,059,114	4,704,119,951
Funded status	(15,907,426)	(454,798,331)
Pension cost (excluding effects of settlements, curtailments and termination benefits) for fiscal year	151,433,757	172,774,575
Discount rate	4.70%	3.95%
Participants as of Census Date	**January 1, 2014**	**January 1, 2013**
Active employees	17,684	17,631
Participants with deferred benefits	3,642	2,479
Participants receiving benefits	16,041	16,292
Total	37,367	38,141
Plan Accounting (ASC 960)	**January 1, 2014**	**January 1, 2013**
Present value of accumulated benefits	4,105,351,485	3,935,881,858
Market value of assets with receivable contributions	4,726,059,114	4,704,119,951
Plan accounting discount rate	6.00%	6.50%

Minimum required contribution and funding policy

All monetary amounts shown in US Dollars

Plan Year Beginning	January 1, 2014	January 1, 2013
Minimum Required Contribution [MRC]		
Prior to application of funding balances	67,364,098	54,762,687
Net of available funding balances	0	0
Sponsor's Funding Policy Contribution	71,463,632	0

Our understanding of the current sponsor's funding policy is to contribute the greater of the FAS service cost and the minimum required contribution, utilizing credit balances as available. We understand the sponsor may deviate from this policy based on cash, tax or other considerations.

The minimum required contribution for the 2014 plan year must be partially satisfied in quarterly installments during the plan year, with a final payment due by September 15, 2015. These requirements may be satisfied through contributions and/or an election to apply the available funding balances. The minimum required contribution is determined assuming it is paid as of the valuation date for the plan year. Contributions made on a date other than the valuation date must be adjusted for interest at the plan's effective interest rate. The minimum funding schedule, before reflecting any funding balance elections or amounts already contributed for the 2014 plan year prior to the issuance of this report, is shown below:

All monetary amounts shown in US Dollars

Due Date	Amount
April 15, 2014	0
July 15, 2014	0
October 15, 2014	0
January 15, 2015	0
September 15, 2015	73,996,191

If a plan has a funding shortfall for the current plan year, quarterly contributions will be required for the following plan year.

Because the plan has a funding shortfall, quarterly contributions for the 2015 plan year will be required. Quarterly contributions for the 2015 plan year will not exceed $16,841,025 per payment, based on this year's valuation results.

The preliminary[1] minimum funding schedule for the 2015 plan year, before reflecting any funding balance elections, is shown below:

All monetary amounts shown in US Dollars

Plan Year	2015
Preliminary Schedule of Minimum Funding Requirements	
April 15, 2015	16,841,025
July 15, 2015	16,841,025
October 15, 2015	16,841,025
January 15, 2016	16,841,025
September 15, 2016	To be determined by 2015 valuation

[1] The final schedule is to be determined by the 2015 valuation.

Change in minimum funding requirement and funding shortfall (funding surplus)

The minimum funding requirement increased from $54,762,687 for the 2013 plan year to $67,364,098 for the 2014 plan year, and the funding shortfall (surplus) increased from $(6,653,964) on January 1, 2013 to $229,555,042 on January 1, 2014, as set forth below:

All monetary amounts shown in US Dollars

	Minimum Funding Requirement	Funding Shortfall (Surplus)
Prior year	54,762,687	(6,653,964)
Change due to:		
Expected based on prior valuation, contributions, and use of/creation of funding balances	7,664,167	3,831,768
Sponsor election to reduce funding balances	0	0
Unexpected noninvestment experience	3,203,628	(19,920,048)
Unexpected investment experience	0	(5,588,942)
Assumption changes	1,733,616	257,886,228
Method changes	0	0
Unpredictable contingent events	0	0
Becoming at-risk	0	0
Plan amendments	0	0
Current year	67,364,098	229,555,042

Significant reasons for these changes include the following:

- The plan's effective interest rate decreased 52 basis points compared to the prior year, which increased the minimum funding requirement and the funding shortfall.
- Investment experience was more favorable than expected which decreased the the funding shortfall.
- Demographic experience was more favorable than expected which decreased the the funding shortfall. There was an increase in minimum funding requirements due to a higher target normal cost relating to expected future benefit accruals.

Funding ratios

The Pension Protection Act of 2006 (PPA) defines several Funding Ratios. All of these ratios are based on a ratio of plan assets to plan liabilities, but the assets and liabilities are defined differently for different purposes. Depending on the purpose, the assets may be market value or, if different, a smoothed actuarial value of assets, and may be reduced by the prefunding balance or all funding balances. The liabilities may be based on the funding target, funding target disregarding at-risk assumptions, or the funding target calculated using at-risk assumptions (see the At-Risk status section below for a discussion of at-risk assumptions), and may or may not reflect the interest rate corridors of MAP-21.

Following are the key funding ratios and their implications for the 2014 or 2015 plan years.

Purpose of Ratio	Percent	Threshold	Implications
January 1, 2013 Funding Ratios			
Use of the funding balances to satisfy the 2014 Minimum Required Contribution (MRC)	104.88%	80%	Because the percent is greater than or equal to the threshold, the funding balances can be used to satisfy 2014 MRC
Quarterly contribution exemption test for 2014	100.16%	100%	Because the percent is greater than or equal to the threshold, quarterly contributions are not required for 2014
At-risk Prong 1 Test for 2014	100.16%	80%	Because at least one of the percents is greater than or equal to the thresholds, the plan is not at risk in 2014
At-risk Prong 2 Test for 2014	N/A	70%	
January 1, 2014 Funding Ratios			
Use of the funding balances to satisfy the 2015 MRC	98.00%	80%	Because the percent is greater than or equal to the threshold, the funding balances can be used to satisfy 2015 MRC
Quarterly contribution exemption test for 2015	94.56%	100%	Because the percent is greater than or equal to the threshold, quarterly contributions are not required for 2015
At-risk Prong 1 Test for 2015	94.56%	80%	Because at least one of the percents is greater than or equal to the thresholds, the plan is not at risk in 2015
At-risk Prong 2 Test for 2015	N/A	70%	
PBGC 4010 filing in 2015	81.47%	80%	Because the percent is greater than or equal to the threshold, this plan does not trigger a 4010 filing in 2015
PBGC variable premium for 2014	97.64%	100%	Because the percent is less than the threshold, PBGC variable premiums are required in 2014

January 1, 2014 Funding Ratios (continued)

Exempt from establishing SAB – prefunding balance applied to the 2014 MRC	110.21%	100%	Because the percent is greater than or equal to the threshold, if prefunding balance is applied to the 2014 MRC, a new Shortfall Amortization Base (SAB) is not created
Exempt from establishing SAB – prefunding balance not applied to the 2014 MRC	110.21%	100%	Because the percent is greater than or equal to the threshold, if prefunding balance is not applied to the 2014 MRC, a new Shortfall Amortization Base (SAB) is not created
Eliminate SABs	94.56%	100%	Because the percent is less than the threshold, the Shortfall Amortization Bases are not eliminated

Benefit limitations

The Adjusted Funding Target Attainment Percentage (AFTAP) for the plan year beginning January 1, 2014 is 110.21%. This AFTAP may be changed by subsequent events.

As requested by American Electric Power Co. in your letter dated April 30, 2014, this report is intended to constitute a “specific certification” of the AFTAP, effective as of April 30, 2014 for the plan year beginning January 1, 2014 for the purpose of determining benefit restrictions under IRC §436 for the American Electric Power System Retirement Plan. This AFTAP certification is based on the data, methods, assumptions, plan provisions, annuity purchase information, and other information provided in this report. Please see the Appendices for additional information. Note that the AFTAP certification provided herein may be superseded by a subsequent AFTAP certification for the plan year beginning January 1, 2014. Please see Appendix C for a discussion of the implications of this certified AFTAP.

Under the PPA, a plan may become subject to various benefit limitations if its AFTAP falls below certain thresholds.

If the AFTAP is below 60%, plans are prohibited from paying lump sums or other accelerated forms of distribution. If the AFTAP is at least 60% but less than 80%, the amounts that can be paid are limited. In addition, lump sums to the 25 highest paid employees may be restricted if a plan’s AFTAP is below 110%. These limitations do not apply to mandatory lump sum cash-outs of $5,000 or less. In addition, plans that were completely frozen before September 2005 are exempt from the restrictions on lump sums and other accelerated forms of distribution.

If the AFTAP is below 60%, benefit accruals must cease, amendments to improve benefits cannot take effect, and plant shutdown benefits and other Unpredictable Contingent Event Benefits (UCEBs) cannot be paid without being fully paid for. In addition, if the AFTAP would be below 80% reflecting a proposed amendment, the plan amendment cannot take effect unless actions are taken to increase plan assets.

To avoid these benefit limitations, a plan sponsor may take a variety of steps, including reducing the funding balances, contributing additional amounts to the plan for the prior plan year, contributing special “designated IRC §436 contributions” for the current plan year, or providing security outside the plan. Not all of these approaches are available for all of the restrictions discussed above. For example, restrictions on accelerated distributions cannot be avoided by making designated IRC §436 contributions.

PBGC reporting requirements

Certain financial and actuarial information (i.e., a “4010 filing”) must be provided to the PBGC if the Funding Target Attainment Percentage (FTAP) is less than 80% for any plan in the contributing sponsor’s controlled group. However, this reporting requirement may be waived for controlled groups with no more than $15 million in aggregate funding shortfall. Note that the segment interest rate corridors of MAP-21 do not apply for purposes of determining the FTAP for PBGC 4010 reporting purposes, but they do apply (assuming segment rates are used for funding purposes) for the purpose of determining whether there is $15 million in aggregate funding shortfall in the controlled group.

The 2014 FTAP is 81.47%. In addition, we understand that American Electric Power System Retirement Plan is the only pension plan within American Electric Power’s controlled group. As a result, no 4010 filing is expected to be required for 2014 as a result of the plans’ funded status. However, a filing may also be required if there are outstanding funding waivers or missed contributions within the controlled group.

At-Risk status for determining minimum required contributions

As defined in the PPA, the plan is not in at-risk status for the 2014 plan year, because the plan’s FTAP for the 2013 plan year was at least 80%, and/or the plan’s FTAP measured using “at-risk assumptions” was at least 70%.

As defined in the PPA, the plan will not be in at-risk status for the 2015 plan year, because the plan’s FTAP for the 2014 plan year is at least 80%, and/or the plan’s FTAP measured using “at-risk assumptions” is at least 70%.

Pension cost and funded position

The cost of the pension plan is determined in accordance with ASC 715. The Fiscal 2014 pension cost for the plan is $151,433,757.

Under ASC 715, the funded position (fair value of plan assets less the projected benefit obligation, or “PBO”) of each pension plan at the plan sponsor’s fiscal year-end (measurement date) is required to be reported as an asset (for overfunded plans) or a liability (for underfunded plans). The PBO is the actuarial present value of benefits attributed to service rendered prior to the measurement date, taking into consideration expected future pay increases for pay-related plans. The plan’s overfunded/(underfunded) PBO as of January 1, 2014 was $(15,907,426), based on the fair value of plan assets of $4,726,059,114 and the PBO of $4,741,966,540.

Fiscal year-end financial reporting information and disclosures are prepared before detailed participant data and full valuation results are available. Therefore, the funded position at December 31, 2013 was derived from a roll forward of the January 1, 2013 valuation results, adjusted for the year-end discount rate, changes in other key assumptions and asset values, as well as significant changes in plan provisions and participant population. The fiscal year-end December 31, 2014 financial reporting information will be developed based on the results of the January 1, 2014 valuation, projected to the end of 2014 and similarly adjusted for the year-end discount rate and asset values, as well as significant changes in plan provisions and participant population.

Change in pension cost and funded position

The pension cost decreased from $172,774,577 in fiscal 2013 to $151,433,757 in fiscal 2014 and the funded position improved from $(454,798,331) to $(15,907,426), as set forth below:

	Pension Cost	Funded Position
Prior year	172,774,577	(454,798,331)
Change due to:		
▸ Expected based on prior valuation and contributions during prior year	(25,013,429)	(13,990,110)
▸ Unexpected noninvestment experience	(2,942,248)	21,683,562
▸ Unexpected investment experience	(1,100,902)	33,989,549
▸ Assumption changes	7,715,520	397,207,904
▸ Plan amendments	0	0
▸ Method change	0	0
▸ Interim events	0	0
Current year	151,433,518	(15,907,426)

Significant reasons for these changes include the following:

- The return on the fair value of plan assets since the prior measurement date was greater than expected, which decreased the pension cost and improved the funded position.
- The return on the market-related value of plan assets, which reflects gradual recognition of asset gains and losses over the past five years, was greater than expected, which decreased the pension cost.
- The discount rate increased 73 basis points compared to the prior year, which decreased the pension cost and caused the funded position to improve.
- The interest rate used to convert forms of payment was increased, which increased the pension cost and caused the funded status to decrease.
- The expected return on assets decreased 50 basis points which increased the pension cost.
- Demographic experience was more favorable than expected which decreased the pension cost and improved the funded position.

Basis for valuation

Appendix A summarizes the assumptions and methods used in the valuation. Appendix B summarizes the principal provisions of the plan being valued.

Changes in Assumptions

The discount rate decreased from 3.95% to 4.70%.

The mortality table used to value the benefit obligations was updated from the RP2000 with projections to 2020 for annuitants and to 2028 for nonannuitants to RP2000 with projections to 2021 for annuitants and to 2029 for nonannuitants.

The mortality used to convert to 417(e) based forms of payment was updated for an additional year of mortality improvements.

The lump sum coversion rate was changed from 5.10% to 5.90%.

The expected return on assets was decreased from 6.50% to 6.00%.

Changes in Methods

None.

Changes in Benefits Valued

Pay credits for participants on long-term disability were eliminated.

This page is intentionally blank

Actuarial certification

This valuation has been conducted in accordance with generally accepted actuarial principles and practices. However please note the information discussed below regarding this valuation.

Reliances

In preparing the results presented in this report, we have relied upon information regarding plan provisions, participants, assets and sponsor elections provided by American Electric Power Co. and other persons or organizations designated by American Electric Power Co.. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations. In addition, the results in this report are dependent on contributions reported for the prior plan year and maintenance of funding balance elections after the valuation date. We have relied on all the information provided as complete and accurate. The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, assets, plan provisions or information regarding contributions or funding balance elections provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies, as corrected by American Electric Power Co., may produce materially different results that could require that a revised report be issued.

Assumptions and methods under ERISA and the Internal Revenue Code for funding purposes

The plan sponsor selected, as prescribed by regulation, key assumptions and funding methods (including asset valuation method and choice among prescribed interest rates) employed in the development of the contribution amounts and communicated them to us in the letter dated April 30, 2014. To the extent not prescribed by ERISA, the Internal Revenue Code and regulatory guidance from the Treasury and the IRS, or selected by the sponsor, the actuarial assumptions and methods employed in the development of the contribution amounts have been selected by Towers Watson, with the concurrence of the plan sponsor. It is beyond the scope of this actuarial valuation to analyze the reasonableness and appropriateness of prescribed methods and assumptions, or to analyze other sponsor elections from among the alternatives available for prescribed methods and assumptions.

Other than prescribed assumptions, ERISA and the Internal Revenue Code require the use of assumptions each of which is “reasonable (taking into account the experience of the plan and reasonable expectations), and which, in combination, offer the actuary’s best estimate of anticipated experience under the plan.” The results shown in this report have been developed based on actuarial assumptions that, to the extent evaluated or selected by Towers Watson, we consider to be reasonable. Other actuarial assumptions could also be considered to be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

A summary of the assumptions and methods used is provided in Appendix A. Note that any subsequent changes in methods or assumptions for the 2014 plan year will change the results shown in this report and could result in plan qualification issues under IRC §436 if the application of benefit restrictions is affected by the change.

Assumptions and methods under ASC 715-30-35

As required by U.S. GAAP, the actuarial assumptions and methods employed in the development of the pension cost have been selected by the plan sponsor. Towers Watson has concurred with these assumptions and methods, except for the expected rate of return on plan assets selected as of January 1, 2014. Evaluation of the expected return assumption was outside the scope of Towers Watson's assignment and would have required substantial additional work that we were not engaged to perform. ASC 715-30-35 requires that each significant assumption "individually represent the best estimate of a particular future event."

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for deferred taxes. Any deferred tax effects in AOCI should be determined in consultation with AEP's tax advisors and auditors.

Nature of actuarial calculations

The results shown in this report are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. The effects of certain plan provisions may be approximated, or determined to be insignificant and therefore not valued. Reasonable efforts were made in preparing this valuation to confirm that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and are not excluded or included inappropriately. The numbers shown in this report are not rounded, but this is for convenience only and should not imply precision, which is not a characteristic of actuarial calculations.

If overall future plan experience produces higher benefit payments or lower investment returns than assumed, the relative level of plan costs or contribution requirements reported in this valuation will likely increase in future valuations (and vice versa). Future actuarial measurements may differ significantly from the current measurements presented in this report due to many factors, including: plan experience differing from that anticipated by the economic or demographic assumptions; increases or decreases expected as part of the natural operation of the methodology used for the measurements (such as the end of an amortization period); and changes in plan provisions or applicable law. It is beyond the scope of this valuation to analyze the potential range of future pension contributions, but we can do so upon request.

See Basis for Valuation in Section 1 above for a discussion of any material events that have occurred after the valuation date that are not reflected in this valuation.

Limitations on use

This report is provided subject to the terms set out herein and in our Master Consulting Services agreement dated July 29, 2004 and any accompanying or referenced terms and conditions.

The information contained in this report was prepared for the internal use of American Electric Power Co. and its auditors, and any organization that provides benefit administration services for the plan, in connection with our actuarial valuation of the pension plan as described in Purposes of Valuation above. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard. American Electric Power Co. may distribute this actuarial valuation report to the appropriate authorities who have the legal right to require American Electric Power Co. to provide them this report, in which case American Electric Power Co. will use best efforts to notify Towers Watson in advance of this distribution. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited without Towers Watson's prior written consent. Towers Watson accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

Professional qualifications

The undersigned consulting actuaries are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to pension plans. Our objectivity is not impaired by any relationship between American Electric Power Co. and our employer, Towers Watson Delaware Inc.

Joseph A. Perko, FSA, EA, MAAA
Senior Consultant
EA#: 14-06491

Ryan S. Carney, FSA, EA, MAAA
Senior Consultant
EA#: 14-06630

Towers Watson Delaware Inc.

April 2014

This page is intentionally blank

Section 2: Actuarial exhibits

2.1 Summary of liabilities for minimum funding purposes

All monetary amounts shown in US Dollars

Plan Year Beginning	January 1, 2014	January 1, 2013
A Funding Target (Disregarding At-risk Assumptions)		
1 Funding target	4,221,975,836	4,024,284,946
2 Target normal cost	67,364,098	61,416,651
B Funding Target (At-risk Assumptions)		
1 Funding target	N/A	N/A
2 Target normal cost	N/A	N/A
C Funding Target		
1 Number of consecutive years at-risk	0	0
2 Funding target		
a Active employees – non-vested benefits	39,046,313	46,678,501
b Active employees – vested benefits	1,666,969,675	1,477,502,076
c Participants with deferred benefits	200,237,513	223,969,681
d Participants receiving benefits	2,315,722,335	2,276,134,688
e Total funding target	4,221,975,836	4,024,284,946
3 Target normal cost	67,364,098	61,416,651

2.2 Change in plan assets during plan year

All monetary amounts shown in US Dollars

Plan Year Beginning		January 1, 2013
A	**Reconciliation of Market Value of Assets**	
1	Market value of assets at January 1, 2013 (including discounted contributions receivable)	4,704,119,951
2	Discounted contributions receivable at January 1, 2013	0
3	Market value of assets at January 1, 2013 (excluding contributions receivable)	4,704,119,951
4	Employer contributions	
	a For prior plan year	0
	b For current plan year	0
	c IRC §436 contributions for current plan year	0
	d Total	0
5	Employee contributions	0
6	Benefit payments	(324,352,206)
7	Administrative expenses paid by plan	(3,461,590)
8	Transfers from/(to) other plans	0
9	Investment return	349,752,959
10	Market value of assets at January 1, 2014 (excluding contributions receivable)	4,726,059,114
11	Discounted contributions receivable at January 1, 2014	0
12	Market value of assets at January 1, 2014 (including discounted contributions receivable)	4,726,059,114
B	**Rate of Return on Invested Assets (i.e., for crediting unused funding balances)**	
1	Rate of return	7.70%

2.3 Development of actuarial value of assets

AEP elected a smoothing method that uses seven monthly data points to calculate the AVA.

All monetary amounts shown in US Dollars

Plan Year Beginning	January 1, 2014

Development of AVA

Month	Expenses	Benefit Payments	Contributions	Fair Value at Beginning of Month
July 2013	136,103	24,606,132	0	4,591,389,538
August 2013	89,278	24,772,844	0	4,656,756,136
September 2013	430,032	29,206,058	0	4,577,382,615
October 2013	28,600	25,031,111	0	4,632,464,881
November 2013	54,390	24,063,803	0	4,714,705,399
December 2013	197,042	26,391,884	0	4,706,008,841

AVA with receivables

A	**Preliminary Actuarial Value of Assets before Corridor as of January 1, 2014**		
	1 Monthly asset values adjusted for expenses and benefit payments rolled forward to January 1, 2014		
		Month	**Asset value**
	a	July 2013	4,582,255,884
	b	August 2013	4,648,336,417
	c	September 2013	4,569,453,408
	d	October 2013	4,630,242,915
	e	November 2013	4,713,300,389
	f	December 2013	4,704,041,590
	g	January 2013	4,726,059,114
	h	Average of monthly asset values	4,653,384,245
	2 Preliminary Actuarial Value of Assets and before application of corridor		4,653,384,245
B	Lower Bound of Corridor (90% of A12 from prior page)		4,253,453,203
C	Upper Bound of Corridor (110% of A12 from prior page)		5,198,665,025
D	**Actuarial Value of Assets as of January 1, 2014 (A2 but not smaller than B nor larger than C)**		4,653,384,245

2.4 Calculation of minimum required contribution

All monetary amounts shown in US Dollars

Reconciliation of Funding Balances as of January 1, 2014		Funding Standard Carryover Balance	Prefunding Balance	Total
A	**Determination of Funding Balances**			
1	Funding balance as of January 1, 2013	189,814,041	478,656,586	668,470,627
2	Amount used to offset prior year minimum required contribution[1]	54,762,687	0	54,762,687
3	Adjustment for investment experience	10,398,954	36,856,557	47,255,511
4	Amount of additional prefunding balance created by election	N/A	0	0
5	Amount of funding balance reduction for current year by election or deemed election	0	0	0
6	Funding balance as of January 1, 2014	145,450,308	515,513,143	660,963,451

Plan Year Beginning		January 1, 2014
B	**Calculation of Minimum Required Contribution**	
1	Target normal cost	67,364,098
2	Funding surplus	0
3	Net shortfall amortization installment	0
4	Waiver amortization installment	0
5	Minimum required contribution	67,364,098
6	Funding balance available	660,963,451
7	Remaining cash requirement (assuming sponsor elects full use of the available funding balances)	0

The minimum required contribution is determined as of the plan's valuation date. Any payment made on a date other than the valuation date must be adjusted for interest using the plan's effective interest rate of 5.66%.

Additional details regarding the calculation of the minimum required contribution may be obtained from the Form 5500 Schedule SB forms and attachments.

[1] Net of revoked excess application of funding balance, if any.

2.5 Calculation of estimated maximum deductible contribution

All monetary amounts shown in US Dollars

Based on Plan Year			2014
A	**Basic Maximum**		
	1	Funding target	4,221,975,836
	2	Target normal cost	67,364,098
	3	Actuarial value of assets	4,653,384,245
	4	50% of funding target	2,110,987,918
	5	Additional funding target for future compensation or benefit increases	94,122,747
	6	Basic maximum deductible contribution	1,841,066,354
B	**At-risk Maximum**[1]		
	1	Funding target (at-risk assumptions)	N/A
	2	Target normal cost (at-risk assumptions)	N/A
	3	Actuarial value of assets	N/A
	4	At-risk maximum deductible contribution	N/A
C	**Minimum Required Contribution**		67,364,098
D	**Estimated Maximum Deductible Contribution**		1,841,066,354

The estimated maximum deductible contribution applies to the tax year in which the plan year ends, and is based on our understanding of IRC §404(a)(1). Regulatory guidance from the IRS/Treasury is pending. Allocations of costs to inventory have not been considered, and amounts deductible under state law may differ. Deductibility can be influenced by timing of contributions, differences between fiscal year and plan year, and differences (if any) between the years to which prior contributions were assigned for minimum funding purposes and the years in which they were deducted. Our results have not been adjusted for non-deducted contributions included in the valuation assets. We recommend the plan sponsor review with tax counsel the tax-deductibility of all contributions as Towers Watson does not provide legal or tax advice.

The calculation above reflects the interest rate corridors of MAP-21 (including their effect on at-risk status), which is not required in determining the maximum deductible contribution. Not reflecting such corridors would likely result in a higher maximum deductible amount, but would require substantial additional work that may not be of value to the Company. We can discuss not reflecting the corridors if the Company wishes to consider contributions in excess of the estimated maximum amount above.

1 At-risk maximum applies only for plans not in at-risk status for purposes of determining maximum deductible contributions for the plan year.

2.6 ASC 960 (plan accounting) information

All monetary amounts shown in US Dollars

Plan Year Beginning	January 1, 2014
A Present Value of Accumulated Benefits	
1 Vested accumulated benefits	
a Active employees	1,621,820,351
b Participants with deferred benefits	195,202,736
c Participants receiving benefits	2,246,889,732
d Total vested accumulated benefits	4,063,912,819
2 Non-vested accumulated benefits	41,438,666
3 Total accumulated benefits	4,105,351,485
4 Market value of assets[1]	4,726,059,114
B Reconciliation of Present Value of Accumulated Benefits	
1 Present value of accumulated benefits as of December 31, 2012	3,935,640,036
2 Changes during the year due to:	
a Benefits accumulated	49,053,407
b Actuarial (gains)/losses	16,024,740
c Decrease in the discount period	246,611,103
d Actual benefits paid	(324,352,206)
e Assumption changes	164,374,405
f Plan amendments	0
g Net increase/(decrease)	151,711,449
3 Present value of accumulated benefits as of December 31, 2013	4,105,351,485

Actuarial Assumptions and Methods

The same actuarial assumptions shown in Appendix A were used to determine the present value of accumulated benefits, except a discount rate of 6.00% was used. For the prior valuation, a discount rate of 6.50% was used. The same plan provisions shown in Appendix B were used to determine the present value of accumulated benefits.

1 Assets include accrued contributions for the 2013 plan year of $ 0 not yet deposited at January 1, 2014.

2.7 Pension obligations and funded position under U.S. GAAP (ASC 715)

All monetary amounts shown in US Dollars

Measurement Date		January 1, 2014	January 1, 2013
A	**Obligations**		
1	Accumulated Benefit Obligation (ABO)	4,623,245,673	5,029,758,827
2	Future salary increases	118,720,867	129,159,455
3	Projected benefit obligation (PBO)	4,741,966,540	5,158,918,282
B	**Assets**		
1	Fair value [FV]	4,726,059,114	4,696,196,951
2	Investment losses/(gains) not yet in market-related value	(218,503,581)	(306,922,548)
3	Market-related value	4,507,555,533	4,397,197,403
C	**Funded Position**		
1	Overfunded/(underfunded) PBO	(15,907,426)	(454,798,331)
2	PBO funded percentage	99.7%	91.2%
D	**Amounts in Accumulated Other Comprehensive Income**		
1	Prior service cost/(credit)	7,900,618	10,408,177
2	Net actuarial loss/(gain)	1,489,707,968	2,098,866,513
3	Total	1,497,608,586	2,109,274,690
E	**Key Assumptions**		
1	Discount rate	4.70%	3.95%
2	Rate of compensation increase	Rates vary by age from 3.5% to 11.5%	Rates vary by age from 3.5% to 11.5%
F	**Census Date**	January 1, 2014	January 1, 2013

The results above may differ from the amounts reported in American Electric Power Co.'s December 31, 2013 financial statements because year-end financial reporting is prepared before the corresponding valuation results are available.

2.8 Pension cost under U.S. GAAP (ASC 715)

All monetary amounts shown in US Dollars

Fiscal Year Ending			December 31, 2014	December 31, 2013
A	**Pension Cost**			
	1	Service cost	71,463,632	68,688,725
	2	Interest cost	217,701,098	199,615,109
	3	Expected return on assets	(261,710,475)	(277,771,978)
	4	Net prior service cost/(credit) amortization	2,505,561	2,507,559
	5	Net loss/(gain) amortization	121,473,941	179,735,160
	6	Net periodic pension cost/(income)	151,433,757	172,774,575
	7	Curtailments	0	0
	8	Settlements	0	0
	9	Special/contractual termination benefits	0	0
	10	Total pension cost	151,433,757	172,774,577
B	**Key Assumptions**[1]			
	1	Discount rate	4.70%	3.95%
	2	Rate of return on assets	6.00%	6.50%
	3	Cash balance crediting rate	4.00%	4.00%
	4	Rate of compensation increase	Rates vary by age from 3.5% to 11.5%	Rates vary by age from 3.5% to 11.5%
C	**Census Date**		January 1, 2014	January 1, 2013

[1] These assumptions were used to calculate Net Periodic Pension Cost/(Income) as of the beginning of the year. For other assumptions used, as well as assumptions used for interim remeasurements, if any, refer to Appendix A.

2.9 Development of market-related value of assets under U.S. GAAP (ASC 715)

All monetary amounts shown in US Dollars

Fiscal Year Ending				December 31, 2014
Market-Related Value of Assets as of January 1, 2014				
1	Fair value of assets as of January 1, 2014			4,726,059,114
2	Deferred investment (gains)/losses for prior periods			
	Fiscal Year	**(Gain)/Loss**	**Percent Deferred**	**Deferred Amount**
a	2014	(50,899,071)	80%	(40,719,257)
b	2013	(249,128,700)	60%	(149,477,220)
c	2012	10,601,513	40%	4,240,605
d	2011	(162,738,544)	20%	(32,547,709)
e	Total			0
3	Market-Related Value of Assets			4,507,555,533

TOWERS WATSON

This page is intentionally blank

Section 3: Participant data

3.1 Summary of plan participants

All monetary amounts shown in US Dollars

Census Date		January 1, 2014	January 1, 2013
A	**Active Employees**		
1	Number	17,684	17,631
2	Expected plan compensation for year beginning on the valuation date (limited by IRC §401(a)(17))	1,556,194,791	1,573,666,355
3	Average plan compensation	88,000	89,256
4	Average age	47.5	46.8
5	Average credited service	18.0	17.3
6	Average future working life (years)	10.159	10.515
B	**Participants with Deferred Benefits**		
1	Number (non-cash balance)	1,864	2,479
2	Total annual pension (non-cash balance)	10,334,827	21,017,548
3	Average annual pension (non-cash balance)	5,544	8,478
4	Number of cash balance	1,778	1,739
5	Total cash balance	136,112,085	137,581,778
6	Average cash balance	76,553	79,115
7	Average age	53.5	53.5
8	Distribution at January 1, 2014		

NON-CASH BALANCE	Age	Number	Annual annual pension
	Under 40	1	9,303
	40-44	15	3,546
	45-49	175	4,246
	50-54	520	5,388
	55-59	657	5,695
	60-64	440	6,060
	65 and over	56	5,708
	Total	1,864	5,544

CASH BALANCE	Age	Number	Annual annual pension
	Under 40	343	13,388
	40-44	166	28,828
	45-49	237	43,981
	50-54	347	65,692
	55-59	374	109,946
	60-64	238	164,772
	65 and over	73	180,553
	Total	1,778	76,553

C	**Participants Receiving Benefits**		
1	Number	16,041	16,292
2	Total annual pension	238,294,213	240,299,847
3	Average annual pension	14,855	14,750
4	Average age	74.1	73.7
5	Distribution at January 1, 2014		

Age	Number	Annual Pension
Under 55	89	4,201
55-59	621	16,034
60-64	1,979	20,716
65-69	3,289	16,238
70-74	2,639	12,257
75-79	2,468	14,197
80-84	2,297	14,543
85 and over	2,659	12,324
Total	16,041	14,855

3.2 Participant reconciliation

	Active	Deferred Inactive	Currently Receiving Benefits	Total
1 Included in January 1, 2013 valuation	18,137	3,712	16,292	38,141
2 Change due to:				
a New hire and rehire	665	(28)	(2)	635
b Non-vested termination	(106)	0	0	(106)
c Vested termination	(304)	304	0	0
d Retirement	(201)	(132)	333	0
e Disability	0	0	0	0
f Death without beneficiary	(6)	(13)	(557)	(576)
g Death with beneficiary	(2)	0	(266)	(268)
h New beneficiary	0	0	268	268
i Cashout	(499)	(238)	0	(737)
j Miscellaneous	0	37	(27)	10
k Net change	(453)	(70)	(251)	(774)
3 Included in January 1, 2014 valuation	17,684	3,642	16,041	37,367

* 506 participants who were on disability were included in the deferred population at January 1, 2013. Subsequent to the plan change that eliminated pension accruals while on disability, the method to value disabled particpants was changed such that such particpants are now included in the active population.

3.3 Age and service distribution of participating employees

Number distributed by attained age and attained years of credited service

Schedule SB, line 26 - Schedule of Active Participant Data

Attained Age	Years Of Credited Service														
	Under 1			1 to 4			5 to 9			10 to 14			15 to 19		
		Average			Average			Average			Average			Average	
	No.	Comp.	Cash Bal.	No.	Comp.	Cash Bal.	No.	Comp.	Cash Bal.	No.	Comp.	Cash Bal.	No.	Comp.	Cash Bal.
<25	4			223	60,221	3,600	25	63,621	8,828						
25 to 29	20	52,103	1,363	449	65,985	5,129	589	75,436	13,508	10					
30 to 34	21	51,755	1,530	341	68,474	6,620	1,052	80,597	18,022	215	84,082	30,650	7		
35 to 39	17			258	70,186	7,805	888	81,804	21,833	402	91,730	41,374	143	87,564	49,981
40 to 44	17			200	73,759	9,880	736	82,654	25,537	437	97,064	50,986	314	92,321	65,373
45 to 49	8			155	78,501	11,695	517	83,058	29,435	348	95,806	60,308	308	93,582	79,218
50 to 54	13			110	76,300	13,812	416	84,317	33,815	300	93,605	69,122	278	88,124	86,015
55 to 59	16			82	72,774	14,976	277	86,674	40,048	219	95,537	81,574	170	86,821	98,828
60 to 64	7			41	71,026	17,856	131	85,554	42,264	115	92,026	86,597	70	80,598	105,925
65 to 69	2			6			32	90,884	52,011	25	93,230	91,898	15		
>70	1						2			10			3		

Schedule SB, line 26 - Schedule of Active Participant Data

Attained Age	Years Of Credited Service														
	20 to 24			25 to 29			30 to 34			35 to 39			40 & up		
		Average			Average			Average			Average			Average	
	No.	Comp.	Cash Bal.	No.	Comp.	Cash Bal.	No.	Comp.	Cash Bal.	No.	Comp.	Cash Bal.	No.	Comp.	Cash Bal.
<25															
25 to 29															
30 to 34															
35 to 39	4														
40 to 44	162	105,228	94,022	7											
45 to 49	538	101,291	110,050	413	98,912	131,667	30	84,667	143,371						
50 to 54	437	93,130	125,326	955	100,613	159,409	1,013	96,453	184,888	88	87,713	195,855			
55 to 59	320	92,545	144,503	598	93,180	175,854	1,073	102,411	227,243	800	96,370	240,867	42	88,542	252,537
60 to 64	109	82,896	156,010	214	93,095	201,545	299	95,984	246,487	267	98,540	290,900	162	94,961	314,398
65 to 69	16			21	90,477	199,788	26	113,862	311,202	10			27	109,348	420,615
>70	3			2			2						1		

This page is intentionally blank

Appendix A – Statement of actuarial assumptions and methods

Actuarial Assumptions and Methods — Contributions

Economic Assumptions

Interest rate basis:

• Applicable month (published)	October 2013
• Yield curve basis	Segment rates
• MAP-21 applied for funding	Yes
• MAP-21 applied for benefit restrictions	Yes

Funding interest rates:	Reflecting Corridors	Not Reflecting Corridors
• First segment rate	4.43%	1.37%
• Second segment rate	5.62%	4.05%
• Third segment rate	6.22%	5.06%
• Effective interest rate	5.66%	4.15%

Annual rates of increase

- Compensation:

	Age	*Rate*
– Representative rates	< 26	11.50%
	26 – 30	9.50%
	31 – 35	7.50%
	36 – 40	6.50%
	41 – 45	5.00%
	46 – 50	4.00%
	> 50	3.50%
– Weighted average		4.95%

• Cash balance crediting rate	4.00%
• Lump sum/annuity conversion rate	October 2013 segment rates
• Future Social Security wage bases	4.00%
• Statutory limits on compensation	N/A
• Expected rate of return on assets for prior year	6.50% but not greater than the third segment rate

Demographic Assumptions

Inclusion Date	The valuation date coincident with or next following the date on which the employee becomes a participant.
New or rehired employees	It was assumed there will be no new or rehired employees.
Mortality	
• Healthy	Separate rates for non-annuitants (based on RP-2000 “Employees” table without collar or amount adjustments, projected to 2029 using Scale AA and annuitants (based on RP-2000 “Healthy Annuitants” table without collar or amount adjustments, projected to 2021 using Scale AA.
• Disabled	Post-1994 current liability disabled
• Lump sum/annuity conversion	Applicable 417(e) IRS Mortality Table
Termination	Rates varying by age and service:

Percentage leaving during the year		
Attained Age	Less than five years of service	Five or more years of service
< 25	8.00%	8.00%
25 – 29	8.00%	6.00%
30 – 34	8.00%	5.00%
35 – 39	8.00%	3.00%
40 – 49	8.00%	2.50%
> 49	8.00%	4.00%

Disability

Rates apply to employees not eligible to retire and vary by age and sex as indicated by the following sample values:

Percentage becoming disabled during the year		
Age	Male	Female
20	0.060%	0.090%
30	0.060%	0.090%
40	0.074%	0.110%
50	0.178%	0.267%
60	0.690%	1.035%

Retirement

Rates varying by age; average retirement age 61:

Percentage retiring during the year	
Age	Rate
55-57	7.00%
58-60	10.00%
61-63	25.00%
64-65	50.00%
66-69	25.00%
70+	100.00%

Benefit commencement date:	
• Preretirement death benefit	The later of the death of the active participant or the date the participant would have attained age 55.
• Deferred vested benefit	The later of age 55 or termination of employment.
• Disability benefit	Upon disablement.
• Retirement benefit	Upon termination of employment.
Form of payment	40% lump sum; 60% annuity for retirement eligible East grandfathered participants and 75% lump sum; 25% annuity for all other participants. Married participants are assumed to elect the 50% joint and survivor annuity and unmarried participants are assumed to elect the single life annuity. No other optional form of payment election is assumed.
Percent married	80% of male participants; 70% of female participants.
Spouse ages	Wives are assumed to be three years younger than husbands.
Valuation pay	2014 base salary pay (Grandfathered) – not estimated due to freeze of final average pay accruals at December 31, 2010. 2014 expanded pay (Cash Balance) – sum of the following updated one year according to the salary increase assumption: (i) 2013 base salary (ii) a 15% increase for overtime eligible employees and a target bonus percent increase for incentive-eligible employees
At-risk assumptions	If at-risk calculations are required, all participants eligible to elect benefits during the current and subsequent ten plan years are assumed to commence benefits at the earliest possible date under the plan, but not before the end of the current plan year, except in accordance with the regular valuation assumptions. In addition, all participants (not just those eligible to begin benefits within the next 11 years) are assumed to elect the most valuable form of benefit under the plan, which is usually a joint and survivor form of payment.
Timing of benefit payments	Annuity payments are payable monthly at the beginning of the month and lump sum payments are payable on date of decrement.

Methods

Valuation date	First day of plan year.
Funding target	Present value of accrued benefits.
Target normal cost	Present value of benefits expected to accrue during plan year plus plan-related expenses expected to be paid from the trust (based on actual trust expenses paid in previous year, adjusted by the difference between the prior and expected current year PBGC premiums).

Actuarial value of assets	Average of the fair market value of assets on the valuation date and the six immediately preceding months, adjusted for contributions, benefit/expense payments and expected investment returns. The average asset value must be within 10% of fair value, including contributing receivable. The method of computing the actuarial value of assets complies with rules governing the calculation of such values under PPA. These rules produce smoothed values that reflect the underlying market value of plan assets but fluctuate less than the market value. As a result, the actuarial value of assets will be lower than the market value in some years and greater in other years. However, over the long term under PPA's smoothing rules, the method has a bias to produce an actuarial value of assets that is below the market value of assets.
Benefits Not Valued	All benefits were valued except: – Any liabilities that may be reinstated in the event of reemployment – The alternate benefit formula for members who did not elect to withdraw their employee contributions – Any liabilities relating to memebers' unwithdrawn employee contributions – Liabilities related to special benefits as a result of termination due to downsizing and restructuring
Change in Assumptions and Methods Since Prior Valuation	The interest rates used to calculate the funding target, target normal cost and to convert 417(e) based forms of payments were updated from the segment rates as of October 2012 to the segment rates as of October 2013. The required mortality table used to value the funding target and target normal cost was updated to include one additional year of projected mortality improvements. Assumed plan-related expenses of $3,461,590 were added to the target normal cost.
Data Sources	Towers Watson used participant and asset data as of January 1, 2014, supplied by ACS, the third party database for the AEP pension data with the exception of certain elements taken from the dbConnect pension calculator database. Data were reviewed for reasonableness and consistency, but no audit was performed. Assumptions or estimates were made or by Towers Watson actuaries when data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Actuarial Assumptions and Methods — Pension Cost

Economic Assumptions

Discount rate	4.70%
Return on assets*	6.00%

Annual rates of increase

- Compensation:
  - Representative rates

Age	Rate
< 26	11.50%
26 – 30	9.50%
31 – 35	7.50%
36 – 40	6.50%
41 – 45	5.00%
46 – 50	4.00%
> 50	3.50%

  - Weighted average: 4.95%

Cash balance crediting rate	4.00%
Lump sum/annuity conversion rate	5.90%
Future Social Security wage bases	4.00%
Statutory limits on compensation	3.00%

The return on assets shown above is net of investment expenses and administrative expenses assumed to be paid from the trust.

* Also used as discount rate for plan accounting (ASC 960) purposes.

Demographic Assumptions

Inclusion Date	The valuation date coincident with or next following the date on which the employee becomes a participant.
New or rehired employees	It was assumed there will be no new or rehired employees.
Mortality	
Healthy	Separate rates for (1) non-annuitants (based on RP-2000 "Employees" table without collar or amount adjustments, projected to 2029 using Scale AA and (2) annuitants (based on RP-2000 "Healthy Annuitants" table without collar or amount adjustments, projected to 2021 using Scale AA.
Disabled	RP2000 disabled retiree, no projection.
Lump sum/annuity conversion	Applicable 417(e) IRS Mortality Table
Termination	Rates varying by age and service

Percentage leaving during the year		
Attained Age	Less than five years of service	Five or more years of service
< 25	8.00%	8.00%
25 – 29	8.00%	6.00%
30 – 34	8.00%	5.00%
35 – 39	8.00%	3.00%
40 – 49	8.00%	2.50%
> 49	8.00%	4.00%

Disability — Rates apply to employees not eligible to retire and vary by age and sex a indicated by the following sample values:

Percentage becoming disabled during the year		
Age	Male	Female
20	0.060%	0.090%
30	0.060%	0.090%
40	0.074%	0.110%
50	0.178%	0.267%
60	0.690%	1.035%

Retirement	Rates varying by age; average retirement age 61:

Percentage retiring during the year	
Age	Rate
55-57	7.00%
58-60	10.00%
61-63	25.00%
64-65	50.00%
66-69	25.00%
70+	100.00%

Benefit commencement date:

- Preretirement death benefit — The later of the death of the active participant or the date the participant would have attained age 55.
- Deferred vested benefit — The later of age 55 or termination of employment.
- Disability benefit — Upon disablement.
- Retirement benefit — Upon termination of employment.

Form of payment	40% lump sum; 60% annuity for retirement eligible East grandfathered participants and 75% lump sum; 25% annuity for all other participants. Married participants are assumed to elect the 50% joint and survivor annuity and unmarried participants are assumed to elect the single life annuity. No other optional form of payment election is assumed.
Percent married	80% of male participants; 70% of female participants.
Spouse ages	Wives are assumed to be three years younger than husbands.
Valuation pay	2014 base salary pay (Grandfathered) – not estimated due to freeze of final average pay accruals at December 31, 2010. 2014 expanded pay (Cash Balance) – sum of the following updated one year according to the salary increase assumption: (i) 2013 base salary (ii) a 15% increase for overtime eligible employees and a target bonus percent increase for incentive-eligible employees
Administrative expenses	Discount rate is net of expenses paid by the trust.
Timing of benefit payments	Annuity payments are payable monthly at the beginning of the month and lump sum payments are payable on date of decrement.

Methods

Service cost and projected benefit obligation	Projected unit credit
Market-related value of assets	The market value on the valuation date less the following percentages of prior years' investment gains and losses: – 80% of the prior year – 60% of the second prior year – 40% of the third prior year – 20% of the fourth prior year The investment gain or loss is calculated each year by: – Rolling forward the prior year's fair value of assets with actual contributions, benefit payments and expected return on investments using the long-term yield assumption – Comparing the actual fair value of assets to the expected value calculated above.
Benefits not valued	All benefits were valued except: – Any liabilities that may be reinstated in the event of reemployment – The alternate benefit formula for members who did not elect to withdraw their employee contributions – Any liabilities relating to members' unwithdrawn employee contributions – Liabilities related to special benefits as a result of termination due to restructuring or downsizing
Change in assumptions and methods since prior valuation	The discount rate was decreased from 3.95% to 4.70%. The mortality table used to value the benefit obligations was updated from the RP2000 with projections to 2020 for annuitants and to 2028 for nonannuitants to RP2000 with projections to 2021 and 2029, respectively. The mortality table used for lump sum/annuity conversions was updated for an additional year of mortality improvements. Accruals for particpants in LTD status were frozen. The lump sum conversion rate increased from 5.10% to 5.90%. The expected return on assets was changed from 6.50% to 6.00%.
Data Sources	Towers Watson used participant and asset data as of January 1, 2014, supplied by ACS, the third party database for the AEP pension data with the exception of certain elements taken from the dbConnect pension calculator database. Data were reviewed for reasonableness and consistency, but no audit was performed. Assumptions or estimates were made or by Towers Watson actuaries when data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Appendix B1 : Summary of plan provisions covered by the former East Retirement Plan

Plan Provisions	
Effective Date	May 1, 1955. Restated effective January 1, 2012.
Recent Amendments	Executed as of April 3, 2012.
Covered Employees	Employees become Members of the Plan on the first day of the month following completion of one year of service.
Participation Date	Date of becoming a covered employee.
Definitions	
Grandfathered employee	If, on December 31, 2000, either: – Participating in AEP System Retirement Plan, or – In one-year waiting period for AEP System Retirement Plan participation.
Vesting service	A period of time from employment date to termination date and, in general, includes periods of severance that are not in the excess of 12 months.
Accredited service	Elapsed time from date of hire (from benefit service start date).
Cash balance pay	Pay received during the year, including base pay, overtime, shift differential/Sunday premium pay and incentive pay, subject to IRS limits.
Covered compensation amount	The average of the Social Security taxable wage based during the 35-year period including the year in which the participant retires, dies, becomes disabled or otherwise terminates employment. This monthly average is calculated to the next lower or equal whole dollar amount and is then rounded to nearest $50.
Final average pay	Average of the highest 36-consecutive months of base pay out of the last 120 months of employment, subject to IRS limits.
Normal retirement date (NRD)	The first day of the calendar month whose first day is nearest the later of the member's 65th birthday or the completion of five years of Vesting Service.

Cash balance account

Recordkeeping account to which annual Interest Credits and annual Company Credits are credited. The cash balance account is updated at the end of each plan year and is equal to:

Cash Balance Account as of the
end of the prior plan year
+
Interest Credits
+
Company Credits

Cash balance benefit

Cash Balance Account converted to a monthly annuity

Opening balance

For those participating in or eligible for the AEP System Retirement Plan on December 31, 2000, opening balance is calculated as follows:

- Present value of monthly normal retirement benefit determined as of December 31, 2000, and payable at age 65 (or current age if older)
  - Present value determined based on 5.78% interest and IRS regulated mortality (GAM83 Unisex) data for lump sums (postretirement only)

Plus

- Credit for early retirement subsidy for monthly payments beginning at age 62 (or current age if older)

Plus

- Transition credit based on age, service and pay received in 2000 (see “Company Credits” for credit percentages)
  - Age and service based on completed whole years as of December 31, 2000.

For employees hired on or after January 1, 2001, opening balance is $0.

Interest credits

Interest credits are applied to beginning of year account balance on December 31 each year.

Based on the average 30-year Treasury Bond rate for November of the previous year.

Minimum of 4%.

Company credits

Applied to account balance on December 31 or termination date if earlier.

Amount is a percentage of eligible pay received during the year, based on age plus years of Vesting Service (age and service in completed whole years as of December 31).

Age Plus Years of Service	*Annual Company Credit*
Less than 30	3.0%
30 – 39	3.5%
40 – 49	4.5%
50 – 59	5.5%
60 – 69	7.0%
70+	8.5%

Monthly Grandfathered Benefit	Sum of (1), (2) and (3): (1) 1.10% of Final Average Pay x Accredited Service up to 35 years (2) 0.50% of Final Average Pay Less Covered Compensation x Accredited Service up to 35 years (3) 1.33% of Final Average Pay x Accredited Service between 35 and 45 years Accruals for the grandfathered benefit ceased on December 31, 2010.
Long-term disability and paid leaves	Participants do not receive company credits while on long-term disability. Vesting service continues.
Unpaid leave	No compensation for annual Company Credit. Vesting service continues.

Eligibility for Benefits

Normal retirement	All members at or after their Normal Retirement Date.
Early retirement	Any time after attainment of age 55 and completion of five years of vesting. Applicable only to grandfathered benefits.
Postponed retirement	Retirement after Normal Retirement Date.
Vested termination	All members who terminate employment after completion of three years of Vesting Service, or upon death.
Disability	All members who are unable to work at own occupation solely because of sickness or injury for the first 24 months of disability. After 24 months of disability, the participant is eligible if unable to work at any gainful occupation for which the participant may be able, or may reasonably become qualified by education, training or experience, to perform.
Surviving spouse	The surviving spouse of a Grandfathered Member who retired or is eligible to retire on Normal or Early Retirement and who was married to that spouse for the year preceding commencement and whose grandfathered benefit exceeds his or her Cash Balance Benefit.
Preretirement death	Beneficiary of deceased member.

Benefits Paid Upon the Following Events

Normal retirement	For Grandfathered Employees, the better of the monthly grandfathered benefit or the Cash Balance Benefit determined as of Normal Retirement Date. For all other employees, the Cash Balance Benefit determined as of Normal Retirement Date.
Early retirement	For Grandfathered Employees, the better of: (1) The monthly grandfathered retirement benefit reduced by 3% per year for each year commencement precedes age 62, and (2) The Cash Balance Benefit determined as of the Early Retirement Date. For all other employees, the Cash Balance Benefit determined as of the Early Retirement Date.

Deferred vested retirement	The accrued Normal Retirement Benefit (better of Cash Balance and Grandfathered Benefits, if eligible), payable at Normal Retirement Date or actuarially reduced and payable at any age.
Disability	The greater of (1) or (2): (1) Accrued Grandfathered Retirement Benefit reduced as in the Early Retirement Benefit. If retirement occurs prior to age 55, the benefit is further reduced actuarially from age 55. The Disability Retirement Benefit will reflect Accredited Service that accrued (at most recent rate of base earnings) to a member while receiving benefits under the Company's LTD plan. (2) The Cash Balance Benefit with continued Company Credits while disabled. Benefit (1) applies for Grandfathered Employees only.
Preretirement death	Better of (1) or (2): (1) The grandfathered monthly benefit as if the employee commenced a 60% qualified joint and survivor benefit at his earliest retirement date (2) Annuity equivalent of Cash Balance account or the cash balance account. Benefit (1) applies for a Grandfathered Employee whose beneficiary is his or her spouse.
Surviving spouse benefits	A benefit payable for life equal to 30% of the single life annuity payable to the grandfathered member. The spouse's benefit is actuarially reduced for each year by which the spouse is more than ten years younger than the member. Payable to Grandfathered Employees only.

Other Plan Provisions

Forms of payment

- Grandfathered employees

The following are available for Grandfathered Employees for both the Grandfathered Benefit and the Cash Balance Benefit:

- Full lump sum payment.
- Combination of partial lump sum (25%, 50% or 75% of full lump sum) with remainder paid as a monthly benefit (see below).
- Monthly payment:
  - Single life annuity.
  - Optional joint annuities (spouse or other beneficiary).
    - Available in 40%, 50%, 60%, 75%, 100%.
    - Can elect pop-up and/or level income options.
  - Automatic company-paid 30% surviving spouse annuity included in Grandfathered Benefit annuity if terminate on or after age 55 and married at least one year. Cash Balance Benefit is actuarially reduced for this feature.

A one-time option to elect a lump sum of the accrued benefit for terminated vested participants whose benefit was determined in no way by reference to either the AEP or CSW cash balance formulas was offered during the period from May 1, 2012 through June 30, 2012. Participants eligible for the window were also permitted to elect any of the other optional forms of payment generally applicable to such a participant under the normal terms of the plan document. Any participant who elected to commence benefits under this window, regardless of lump sum or annuity election, had a benefit commencement date of August 1, 2012.

- Employees hired on or after January 1, 2001

The following are available for those hired on or after January 1, 2001:

- Full lump sum payment.
- Combination of partial lump sum (25%, 50% or 75% of full lump sum) with remainder paid as a monthly benefit (see below).
- Monthly payment:
  - Single life annuity.
  - Joint annuities (spouse or other beneficiary).
    - Available in 50%, 75%, 100%.

Form of payment conversion for non-417(e) covered conversions

- Cash balance: 7.50% interest and the applicable 417(e) Mortality Table.
- Grandfathered benefit: 7.50% interest and the 1974 George B. Buck Mortality Table.

Pension Increases: None.

Plan Participants' Contributions: Prior to January 1, 1978, employee contributions were required as a condition of Membership. In May and June of 1981, Members were permitted an election to withdraw those contributions. Those who did not elect to withdraw have retirement benefits based on a formula that differs from the formulas previously described in this section. However, the number of nonelecting Members is so small that special plan provisions for that group have not been included in this summary.

Maximum on benefits and pay	All benefits and pay for any calendar year may not exceed the maximum limitations for that year as defined in the Internal Revenue Code. The plan provides for increasing the dollar limits automatically as such changes become effective. Increases in the dollar limits are assumed for determining pension cost but not for determining contributions.
Benefits not valued	A small portion of the population made employee contributions to the plan. Because the amount of these contributions is not material to the plan, they are not part of the valuation. Participants who were employees of Columbus Southern Power (CSP) at the time AEP acquired that company have a frozen benefit under the CSP benefit formula at December 31, 1986. Benefits for these participants are the greater of an all-service AEP benefit and a two-part benefit consisting of the frozen CSP benefit plus an AEP benefit accrued from January 1, 1987. Because this applies to a small portion of the population and the CSP frozen benefit is not often the greater benefit for these participants, this benefit is not valued.
Plan status	Ongoing.

Future Plan Changes

Towers Watson is not aware of any future plan changes that are required to be reflected.

Changes in Benefits Valued Since Prior Year

None.

Appendix B2 : Summary of plan provisions covered by the former West Retirement Plan

Plan Provisions	
Effective Date	January 1940. Restated effective January 1, 1997.
Recent Amendments	Executed as of April 3, 2012.
Covered Employees	All full-time employees of a Participating Company employed by CSW before January 1, 2001, and not covered by a union (that has not bargained for coverage) or another pension plan provided by AEP. Part-time employees of the Company had to work more than 1,000 hours in the first anniversary year or subsequent calendar years.
Participation Date	Date of becoming a covered employee

Definitions	
Grandfathered employee	Employees who were at least age 50 with ten years of vesting service of July 1, 1997.
Vesting service	All service from date of hire in completed years.
Credited service	The aggregate of: For the period prior to January 1, 1976: (1) The number of full years in the last continuous period that employee was a participant after June 30, 1970, plus (2) Credited service under any prior plan if service extended to July 1, 1970. For the period beginning on or after January 1, 1976, the number of full years of service.
Cash balance pay	Pay received during the year, including base pay, overtime, shift differential/Sunday premium pay and incentive pay, subject to IRS limits
Final average pay	Highest average annual earnings (base pay only) during any 36 consecutive months in the 120 months before retirement. Any changes in earnings within the last three months before retirement will not be taken into account.
Normal retirement date (NRD)	The first day of the calendar month on or following the member's 65th birthday.

Cash balance account	Recordkeeping account to which annual interest credits and annual company credits are credited. The cash balance account is updated at the end of each plan year and is equal to: Cash Balance Account as of the end of the prior plan year + Interest Credits + Company Credits
Cash balance benefit	Cash Balance Account converted to a monthly annuity
Interest credits	Interest credits are applied to beginning of year account balance on December 31 each year. Based on the average 30-year Treasury Bond rate for November of the previous year. Minimum of 4%.
Company credits	Applied to account balance on December 31 or termination date if earlier. Amount is a percentage of eligible pay received during the year, based on age plus years of Vesting Service (age and service in completed whole years as of December 31).

Age Plus Years of Service	*Annual Company Credit*
Less than 30	3.0%
30 – 39	3.5%
40 – 49	4.5%
50 – 59	5.5%
60 – 69	7.0%
70+	8.5%

Monthly Grandfathered Benefit

Greater of (1) or (2) below with automatic cost of living adjustments upon retirement:

(1) Basic benefit — An annual amount equal to:

The aggregate of a participant's (a) earned benefit (if any) under any prior plan or acquired Company pension plan under which no election was made to receive a paid-up annuity; and (b) participant contributions without interest for the period commencing on or after July 1, 1970. For the period after September 1, 1980, participants will be deemed to have made contributions at the rate of 2% annually of the participant's annual rate of earnings as of January 1.

(2) Minimum benefit:

1-2/3% of final average annual earnings less 50% of participant's annual primary Social Security benefit times years of credited service up to 30 years.

Minimum benefits

The benefit payable will never be less than the frozen accrued benefit as of July 1, 1997, under the prior plan.

Primary Social Security benefit

The annual amount payable under the Social Security Act as amended in effect at the employee's date of retirement. The date as of which the amount is to be determined is:

(1) In the case of an employee (including deferred vested employees) retiring on or after normal retirement date, normal retirement date.

(2) In the case of an employee retiring prior to normal retirement date, the later of employee's 62nd birthday or actual retirement date.

Early retirees and deferred vested employees are assumed to have no earnings after termination in determining the amount of this benefit.

Long-term disability and paid leaves

Participants do not receive company credits while on long-term disability. For the grandfathered formula, the final average pay will be determined as of the date on which the participant became disabled. Vesting service continues.

Unpaid leave

No compensation for annual compensation credit. Vesting service continues.

Eligibility for Benefits

Normal retirement

All members at or after their Normal Retirement Date

Early retirement

Any time after attainment of age 55 and completion of five years of vesting

Postponed retirement

Retirement after NRD.

Vested

The participant's cash balance account is 100% vested when any one of the following applies:

(1) Three years of vesting service

(2) Attainment of age 55 while an employee

(3) Death prior to termination

(4) Upon disability.

Disability

All participants who become permanently and totally disabled. Permanent and total disability is determined by reference to the LTD plan covering that participant.

Surviving spouse

The surviving spouse of a participant who retired or is eligible to retire on normal or early retirement.

Preretirement death

Beneficiary of participant who dies after becoming vested.

Benefits Paid Upon the Following Events

Normal retirement

Grandfathered employees must elect either the cash balance or the grandfathered formula. For purposes of this valuation, the employee is assumed to elect the formula with the higher present value. Employees with a prior plan frozen benefit get the better of the cash balance benefit and the prior plan frozen benefit. For all other employees, the Cash Balance Benefit is determined as of Normal Retirement Date.

Early retirement

Greater of (1) if applicable or (2):

(1) The grandfathered accrued benefit and the prior plan frozen are payable subject to reduction according to the following schedule if payments commence prior to the normal retirement date.

Age at Retirement	*Percent of Benefit Payable*
64	100%
63	100%
62	100%
61	95%
60	90%
59	84%
58	78%
57	72%
56	66%
55	60%

(2) The Cash Balance Benefit determined as of the Early Retirement Date.

Deferred vested retirement

Greater of (1) if applicable or (2):

(1) Grandfathered accrued benefit payable at age 65, or if earlier reduced 5% per year from age 65, 6% per year from age 60 and 7.5% per year compounded from age 55.

(2) Vested cash balance account.

Disability retirement

The greatest of grandfathered accrued benefit, if eligible, based on projected service and frozen pay deferred to age 65, prior plan frozen benefit if eligible and cash balance account with continued pay credits.

Preretirement death

If the beneficiary is the spouse and the participant is a grandfathered/protected plan participant, then:

(1) For an active participant who dies on or after 55th birthday but before retirement, a monthly benefit equal to 50% of the benefit accrued to the date of death without reduction for early retirement is payable immediately as a life annuity to a qualifying spouse.

(2) For an active participant who dies after completing five or more years of vesting service but before age 55, a deferred monthly benefit equal to 50% of the benefit accrued to the date of death reduced as for early retirement is payable as a life annuity to a

qualifying spouse. Benefit commencement is deferred to when the deceased participant would have attained age 55.

(3) For a deferred vested participant who dies before benefits commence, a monthly benefit equal to 50% of the deferred vested benefit reduced for early commencement (as for deferred vesteds) is payable as a life annuity to a qualifying spouse. If death occurs before age 55, the benefit to the spouse is deferred to when the deceased participant would have attained age 55.

The spouse's benefit is actuarially reduced for each year by which the spouse is more than five years younger than the participant.

For all employees, the minimum benefit is the cash balance account immediate annuity, which is also payable if the beneficiary is not the participant's spouse.

Other Plan Provisions

Form of payment

The following are available for those participants who did not work an hour of service on or after January 1, 2003:

- Full lump sum payment.
- Monthly payment:
  - Single life annuity.
  - 50% joint annuity (spouse or other beneficiary).

A one-time option to elect a lump sum of the accrued benefit for terminated vested participants whose benefit was determined in no way by reference to either the AEP or CSW cash balance formulas was offered during the period from May 1, 2012 through June 30, 2012. Participants eligible for the window were also permitted to elect any of the other optional forms of payment generally applicable to such a participant under the normal terms of the plan document. Any participant who elected to commence benefits under this window, regardless of lump sum or annuity election, had a benefit commencement date of August 1, 2012.

The following are available for those participants who work an hour of service on or after January 1, 2003:

- Full lump sum payment.
- Combination of partial lump sum (25%, 50% or 75% of full lump sum) with remainder paid as a monthly benefit (see below).
- Monthly payment:
  - Single life annuity.
  - Joint annuities (spouse or other beneficiary).
    - Available in 50%, 75%, 100%.

Form of payment conversion for non-417(e) covered conversions	
■ Cash balance	7.50% interest and the applicable 417(e) Mortality Table
■ Grandfathered benefit	Factors as specified in Tables I, II, III and IV of Exhibit A to the American Electric Power System Retirement Plan document. 7.50% interest and the 1951 Group Annuity male mortality table to the extent not covered by Tables I, II, III and IV.
Pension Increases	None.
Member Contributions	None.
Maximum on benefits and pay	All benefits and pay for any calendar year may not exceed the maximum limitations for that year as defined in the Internal Revenue Code. The plan provides for increasing the dollar limits automatically as such changes become effective. Increases in the dollar limits are assumed for determining pension cost but not for determining contributions.
Plan status	Continuing accruals. All new entrants to plan are covered under former East plan provision.

Future Plan Changes

Towers Watson is not aware of any future plan changes that are required to be reflected.

Changes in Benefits Valued Since Prior Year

None.

Appendix C : Adjusted Funding Target Attainment Percentage (AFTAP)

American Electric Power Co. retained Towers Watson Delaware Inc. ("Towers Watson") to perform a valuation of its pension plan for the purpose of measuring the plan's AFTAP for the plan year beginning January 1, 2014 in accordance with ERISA and the Internal Revenue Code. This valuation has been conducted in accordance with generally accepted actuarial principles and practices.

The enrolled actuary making this certification is a member of the Society of Actuaries and other professional actuarial organizations and meets their "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States."

We hereby certify that the plan's AFTAP for the plan year beginning January 1, 2014 is 110.21%. This percentage is based on the assumptions, participant data, and plan provisions we relied upon to prepare these results shown in this report, reflects the valuation limitations discussed in this report and is also based on the following additional information:

Annuity Purchases

American Electric Power Co.'s representation that there were no annuity purchases made on behalf of non-highly compensated employees by the plan in the plan years beginning in 2012 and 2013.

Funding Balances

Our understanding is that American Electric Power Co. has not elected to reduce the plan's funding balance as of the first day of the 2014 plan year.

Our understanding is that American Electric Power Co. has elected to apply the plan's funding balances as of the first day of the 2013 and 2014 plan year to the 2013 and 2014 minimum required contribution (MRC), respectively, as follows:

Date	Amount
April 18, 2014 (2013 MRC)	$54,762,687
April 18, 2014 (2014 MRC)	$67,364,098

Our understanding is that American Electric Power Co. has not elected to increase the prefunding balance as of the first day of the 2014 plan year.

Contributions

Our understanding is that American Electric Power Co. has not made any employer contributions after December 31, 2013 and before April 30, 2014 for the 2013 plan year.

Events

There were no plan amendments that took effect in the current plan year that were taken into account for the current plan year's AFTAP certification.

There were no UCEBs that took effect in the current plan year that were taken into account for the current plan year's AFTAP certification.

There were no previously suspended accruals restored during the current plan year that were taken into account for the current plan year's AFTAP certification.

Elections

Our understanding of sponsor elections required under the Pension Protection Act of 2006 (PPA) , with respect to interest rates, Actuarial Value of Assets and other methods and/or assumptions, as confirmed in the Sponsor's letter dated April 30, 2014.

In making this certification, we relied on asset, contribution, funding balance election, and annuity purchase information provided by the Company, including dates and amounts of contributions made to the plan through the date of this certification, dates and amounts of funding balance elections by the Company through the date of this certification, and amounts of annuity purchases in the past two years, as shown above. We have reviewed this information for overall reasonableness and consistency but, consistent with the scope of our engagement, have neither audited nor independently verified this information. We do not certify to the accuracy or completeness of asset, contribution, funding balance election and annuity purchase information, and this certification relies on and is contingent on the accuracy and completeness of this information.

The development of the AFTAP is shown below:

All monetary amounts shown in US Dollars

Plan Year Beginning	January 1, 2014
Actuarial value of assets as of January 1, 2014[1]	4,653,384,245
Funding standard carryover balance at January 1, 2014[2]	145,450,308
Prefunding balance at January 1, 2014[2]	515,513,143
Funding target (disregarding at-risk assumptions)	4,221,975,836
AVA/funding target (disregarding at-risk assumptions)	110.21%
Assets for AFTAP calculation[3]	4,653,384,245
Annuity purchases for NHCEs during 2012 and 2013	0
Reflection of Post-Valuation Date Events not Previously Reflected	
Increase in funding target (disregarding at-risk assumptions) for 2014 amendments/UCEBs/restored accruals[4]	0
IRC §436 contributions made to enable plan amendments/UCEBs/restored accruals to take effect[5]	0
Adjusted funding target, disregarding at-risk assumptions, (includes NHCE annuity purchases and amendments)	0
Adjusted assets (includes NHCE annuity purchases and IRC §436 contributions)	0
Specific AFTAP	
Adjusted Funding Target Attainment Percentage (AFTAP)	110.21%

1 Reflects discounted contributions made for the 2013 plan year only if paid on or before the certification date. Includes security posted by the beginning of the plan year in the form of a bond or cash held in escrow.
2 Reflects elections made to-date (other than elections to apply the funding balances to 2014 MRC).
3 AVA if AVA/Funding Target (disregarding at-risk assumptions) >=100%; otherwise (AVA-funding balances).
4 If amendments/UCEBs/restored accruals (i) went into effect before this specific certification, (ii) were not reflected in the funding valuation and (iii) require AFTAP recertification, or if AFTAP recertification is not required but the plan sponsor decides to reflect the amendment/UCEBs/restored accruals in the specific AFTAP certification.
5 Discounted to January 1, 2014 using the 2014 plan year effective interest rate.

Immediate Implications of AFTAP Certification

We believe that the certified AFTAP of 110.21% for the 2014 plan year has the following implications for benefit limitations described in IRC §436. American Electric Power Co. should review these conclusions with ERISA counsel:

- Benefit accruals called for under the plan without regard to IRC §436 must continue.
- Accelerated distributions called for under the plan without regard to IRC §436 must continue in full.
- Amendments that increase benefits must be evaluated at the time they would take effect to determine if they are permissible.
- Plant shutdown and other unpredictable UCEBs must be evaluated at the time they would take effect to determine if they are permissible.

Implications of 2014 AFTAP for Presumptions in Next Plan Year

Because the AFTAP for the 2014 plan year is at least 90%, the presumed AFTAP for 2015 will remain equal to the 2014 certified AFTAP, and changes in benefit restrictions will not occur, before the 2015 AFTAP is certified, provided that the 2015 AFTAP is certified before the first day of the tenth month of the plan year.

Note, however, that adoption of plan amendments and/or payment of UCEBs may change this result.

Appendix D : Results by business unit

Unless otherwise indicated, the data, assumptions, methods, data and plan provisions upon which the figures in this Appendix D rely are consistent with those indicated throughout the rest of the report.

Summary of key assumptions for Appendix D of 2014 AEP Retirement Plan valuation report:

	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Discount Rate	4.70%	5.30%	5.50%	5.60%	5.70%	5.80%	5.80%	5.80%	5.80%	5.80%
PPA effective interest rate	5.66%	5.16%	5.30%	5.40%	5.50%	5.60%	5.60%	5.60%	5.60%	5.60%
Expected return on assets	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Cash balance crediting rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Lump sum conversion rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%

Expected mortality	IRS-prescribed mortality table for minimum funding purposes, with adoption of RP-2014 and projection scale MP-2014 at year end 2015.
Valuation and data	January 1, 2014

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
SUMMARY OF PLAN PARTICIPANTS FOR THE 2014 VALUATION

Location	*Vested Actives*	*Non-Vested Actives*	*Total Actives*	*Retirees Receiving Benefits*	*Beneficiaries*	*Deferred Vesteds*	*Total Inactives*	*Total Participants*
140 Appalachian Power Co - Distribution	1,023	0	1,023	1,118	405	184	1,707	2,730
215 Appalachian Power Co - Generation	924	0	924	766	231	76	1,073	1,997
150 Appalachian Power Co - Transmission	62	0	62	115	18	16	149	211
Appalachian Power Co. - FERC	**2,009**	**0**	**2,009**	**1,999**	**654**	**276**	**2,929**	**4,938**
225 Cedar Coal Co	0	0	0	91	34	17	142	142
Appalachian Power Co. - SEC	**2,009**	**0**	**2,009**	**2,090**	**688**	**293**	**3,071**	**5,080**
211 AEP Texas Central Company - Distribution	874	0	874	878	251	305	1,434	2,308
147 AEP Texas Central Company - Generation	0	0	0	6	48	24	78	78
169 AEP Texas Central Company - Transmission	102	0	102	68	32	35	135	237
AEP Texas Central Co.	**976**	**0**	**976**	**952**	**331**	**364**	**1,647**	**2,623**
170 Indiana Michigan Power Co - Distribution	574	0	574	642	264	98	1,004	1,578
132 Indiana Michigan Power Co - Generation	382	0	382	281	89	88	458	840
190 Indiana Michigan Power Co - Nuclear	1,124	0	1,124	361	61	281	703	1,827
120 Indiana Michigan Power Co - Transmission	123	0	123	103	16	10	129	252
280 Ind Mich River Transp Lakin	324	0	324	102	41	40	183	507
Indiana Michigan Power Co. - FERC	**2,527**	**0**	**2,527**	**1,489**	**471**	**517**	**2,477**	**5,004**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**2,527**	**0**	**2,527**	**1,489**	**471**	**517**	**2,477**	**5,004**
110 Kentucky Power Co - Distribution	252	0	252	186	70	34	290	542
117 Kentucky Power Co - Generation	94	0	94	97	24	12	133	227
180 Kentucky Power Co - Transmission	29	0	29	11	0	3	14	43
600 Kentucky Power Co. - Kammer Actives	43	0	43	0	0	0	0	43
701 Kentucky Power Co. - Mitchell Actives	244	0	244	0	0	0	0	244
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	97	12	4	113	113
Kentucky Power Co.	**662**	**0**	**662**	**391**	**106**	**53**	**550**	**1,212**
250 Ohio Power Co - Distribution	1,468	0	1,468	1,687	519	228	2,434	3,902
160 Ohio Power Co - Transmission	13	0	13	197	67	20	284	297
Ohio Power Co	**1,481**	**0**	**1,481**	**1,884**	**586**	**248**	**2,718**	**4,199**
167 Public Service Co of Oklahoma - Distribution	660	0	660	435	191	137	763	1,423
198 Public Service Co of Oklahoma - Generation	364	0	364	168	70	57	295	659
114 Public Service Co of Oklahoma - Transmission	81	0	81	50	16	14	80	161
Public Service Co. of Oklahoma	**1,105**	**0**	**1,105**	**653**	**277**	**208**	**1,138**	**2,243**
159 Southwestern Electric Power Co - Distribution	521	0	521	177	95	54	326	847
168 Southwestern Electric Power Co - Generation	588	0	588	182	86	39	307	895
161 Southwestern Electric Power Co - Texas - Distribution	239	0	239	95	39	36	170	409
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	3	0	3	3
194 Southwestern Electric Power Co - Transmission	74	0	74	34	10	14	58	132
Southwestern Electric Power Co.	**1,422**	**0**	**1,422**	**488**	**233**	**143**	**864**	2,286
119 AEP Texas North Company - Distribution	252	0	252	165	83	81	329	581
166 AEP Texas North Company - Generation	0	0	0	101	49	32	182	182
192 AEP Texas North Company - Transmission	48	0	48	23	11	3	37	85
AEP Texas North Co.	**300**	**0**	**300**	**289**	**143**	**116**	**548**	**848**
230 Kingsport Power Co - Distribution	50	0	50	45	16	5	66	116
260 Kingsport Power Co - Transmission	6	0	6	8	1	1	10	16
Kingsport Power Co.	**56**	**0**	**56**	**53**	**17**	**6**	**76**	**132**
210 Wheeling Power Co - Distribution	48	0	48	54	31	3	88	136
200 Wheeling Power Co - Transmission	0	0	0	3	8	0	11	11
Wheeling Power Co.	**48**	**0**	**48**	**57**	**39**	**3**	**99**	**147**
103 American Electric Power Service Corporation	5,019	0	5,019	2,428	477	1,275	4,180	9,199
American Electric Power Service Corp	**5,019**	**0**	**5,019**	**2,428**	**477**	**1,275**	**4,180**	**9,199**
143 AEP Pro Serv, Inc.	0	0	0	1	0	2	3	3
171 CSW Energy, Inc.	87	0	87	3	1	23	27	114
293 Elmwood	82	0	82	5	0	17	22	104
292 AEP River Operations LLC	936	0	936	8	0	107	115	1,051
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**1,105**	**0**	**1,105**	**17**	**1**	**149**	**167**	**1,272**
270 Cook Coal Terminal	15	0	15	13	3	3	19	34
AEP Generating Company	**15**	**0**	**15**	**13**	**3**	**3**	**19**	**34**
104 Cardinal Operating Company	305	0	305	187	53	14	254	559
181 Ohio Power Co - Generation	654	0	654	1,224	389	248	1,861	2,515
AEP Generation Resources - FERC	**959**	**0**	**959**	**1,411**	**442**	**262**	**2,115**	**3,074**
290 Conesville Coal Preparation Company	0	0	0	11	1	2	14	14
AEP Generation Resources - SEC	**959**	**0**	**959**	**1,422**	**443**	**264**	**2,129**	**3,088**
Total	**17,684**	**0**	**17,684**	**12,226**	**3,815**	**3,642**	**19,683**	**37,367**

AMERICAN ELECTRIC POWER - QUALIFIED RETIREMENT PLAN
FUNDED STATUS OF PRESENT VALUE OF ACCUMULATED PLAN BENEFITS (ASC 960) AS OF JANUARY 1, 2014

Location	*Present Value of Vested Benefits*	*Present Value of Non-Vested Benefits*	*Present Value of Accumulated Plan Benefits*	*Market Value of Assets*	*Percent Funded*
140 Appalachian Power Co - Distribution	$284,431,277	$3,309,856	$287,741,133	$311,905,817	108.4%
215 Appalachian Power Co - Generation	239,157,340	2,319,770	241,477,110	264,763,253	109.6%
150 Appalachian Power Co - Transmission	33,733,806	81,977	33,815,783	31,400,384	92.9%
Appalachian Power Co. - FERC	**$557,322,423**	**$5,711,603**	**$563,034,026**	**$608,069,454**	**108.0%**
225 Cedar Coal Co	3,129,088	0	3,129,088	4,585,983	146.6%
Appalachian Power Co. - SEC	**$560,451,511**	**$5,711,603**	**$566,163,114**	**$612,655,437**	**108.2%**
211 AEP Texas Central Company - Distribution	$243,044,304	$783,238	$243,827,542	$274,418,722	112.5%
147 AEP Texas Central Company - Generation	6,726,255	0	6,726,255	14,533,651	216.1%
169 AEP Texas Central Company - Transmission	23,400,366	94,474	23,494,840	26,420,727	112.5%
AEP Texas Central Co.	**$273,170,925**	**$877,712**	**$274,048,637**	**$315,373,100**	**115.1%**
170 Indiana Michigan Power Co - Distribution	$144,632,728	$1,265,419	$145,898,147	$162,166,819	111.2%
132 Indiana Michigan Power Co - Generation	96,522,292	1,275,027	97,797,319	106,393,117	108.8%
190 Indiana Michigan Power Co - Nuclear	181,069,134	2,513,970	183,583,104	220,471,645	120.1%
120 Indiana Michigan Power Co - Transmission	32,553,990	312,533	32,866,523	33,774,470	102.8%
280 Ind Mich River Transp Lakin	27,696,276	513,462	28,209,738	36,874,139	130.7%
Indiana Michigan Power Co. - FERC	**$482,474,420**	**$5,880,411**	**$488,354,831**	**$559,680,190**	**114.6%**
202 Price River Coal	0	0	0	0	0.0%
Indiana Michigan Power Co. - SEC	**$482,474,420**	**$5,880,411**	**$488,354,831**	**$559,680,190**	**114.6%**
110 Kentucky Power Co - Distribution	$63,095,058	$672,919	$63,767,977	$68,385,212	107.2%
117 Kentucky Power Co - Generation	30,644,824	345,124	30,989,948	31,474,046	101.6%
180 Kentucky Power Co - Transmission	5,831,552	19,562	5,851,114	6,182,096	105.7%
600 Kentucky Power Co. - Kammer Actives	4,441,812	59,701	4,501,513	5,425,733	120.5%
701 Kentucky Power Co. - Mitchell Actives	23,833,188	814,006	24,647,194	35,513,146	144.1%
702 Kentucky Power Co. - Mitchell Inactives	21,230,696	0	21,230,696	27,697,105	130.5%
Kentucky Power Co.	**$149,077,130**	**$1,911,312**	**$150,988,442**	**$174,677,338**	**115.7%**
250 Ohio Power Co - Distribution	$377,684,134	$2,932,541	$380,616,675	$433,703,784	113.9%
160 Ohio Power Co - Transmission	43,625,541	18,513	43,644,054	43,515,760	99.7%
Ohio Power Co	**$421,309,675**	**$2,951,054**	**$424,260,729**	**$477,219,544**	**112.5%**
167 Public Service Co of Oklahoma - Distribution	$139,111,847	$538,001	$139,649,848	$160,382,988	114.8%
198 Public Service Co of Oklahoma - Generation	69,324,437	390,464	69,714,901	83,303,607	119.5%
114 Public Service Co of Oklahoma - Transmission	16,534,123	73,483	16,607,606	20,043,420	120.7%
Public Service Co. of Oklahoma	**$224,970,407**	**$1,001,948**	**$225,972,355**	**$263,730,015**	**116.7%**
159 Southwestern Electric Power Co - Distribution	$82,724,696	$438,557	$83,163,253	$101,766,058	122.4%
168 Southwestern Electric Power Co - Generation	92,456,597	983,278	93,439,875	109,720,641	117.4%
161 Southwestern Electric Power Co - Texas - Distributic	45,335,956	205,887	45,541,843	50,874,622	111.7%
111 Southwestern Electric Power Co - Texas - Transmis	140,266	0	140,266	77,692	55.4%
194 Southwestern Electric Power Co - Transmission	12,755,048	75,148	12,830,196	16,157,232	125.9%
Southwestern Electric Power Co.	**$233,412,563**	**$1,702,870**	**$235,115,433**	**$278,596,245**	**118.5%**
119 AEP Texas North Company - Distribution	$59,688,266	$248,405	$59,936,671	$67,393,547	112.4%
166 AEP Texas North Company - Generation	19,264,845	0	19,264,845	24,712,557	128.3%
192 AEP Texas North Company - Transmission	8,068,451	49,742	8,118,193	9,827,102	121.1%
AEP Texas North Co.	**$87,021,562**	**$298,147**	**$87,319,709**	**$101,933,206**	**116.7%**
230 Kingsport Power Co - Distribution	$11,801,061	$57,448	$11,858,509	$12,882,303	108.6%
260 Kingsport Power Co - Transmission	2,428,498	21,666	2,450,164	2,251,944	91.9%
Kingsport Power Co.	**$14,229,559**	**$79,114**	**$14,308,673**	**$15,134,247**	**105.8%**
210 Wheeling Power Co - Distribution	$13,853,409	$25,922	$13,879,331	$15,565,330	112.1%
200 Wheeling Power Co - Transmission	655,442	0	655,442	887,084	135.3%
Wheeling Power Co.	**$14,508,851**	**$25,922**	**$14,534,773**	**$16,452,414**	**113.2%**
103 American Electric Power Service Corporation	$1,227,718,652	$17,288,576	$1,245,007,228	$1,387,290,786	111.4%
American Electric Power Service Corp	**$1,227,718,652**	**$17,288,576**	**$1,245,007,228**	**$1,387,290,786**	**111.4%**
143 AEP Pro Serv, Inc.	$934,735	$0	$934,735	$1,014,265	108.5%
171 CSW Energy, Inc.	7,332,576	348,203	7,680,779	9,701,893	126.3%
293 Elmwood	2,408,829	62,493	2,471,322	5,068,769	205.1%
292 AEP River Operations LLC	24,806,529	718,391	25,524,920	48,044,913	188.2%
189 Central Coal Company	0	0	0	0	0.0%
Miscellaneous	**$35,482,669**	**$1,129,087**	**$36,611,756**	**$63,829,840**	174.3%
270 Cook Coal Terminal	$3,154,805	$39,803	$3,194,608	$3,974,249	124.4%
AEP Generating Company	**$3,154,805**	**$39,803**	**$3,194,608**	**$3,974,249**	**124.4%**
104 Cardinal Operating Company	$67,405,829	$796,536	$68,202,365	$87,358,287	128.1%
181 Ohio Power Co - Generation	266,588,806	1,744,571	268,333,377	363,841,775	135.6%
AEP Generation Resources - FERC	**$333,994,635**	**$2,541,107**	**$336,535,742**	**$451,200,062**	**134.1%**
290 Conesville Coal Preparation Company	2,935,455	0	2,935,455	4,312,441	146.9%
AEP Generation Resources - SEC	**$336,930,090**	**$2,541,107**	**$339,471,197**	**$455,512,503**	**134.2%**
Total	**$4,063,912,819**	**$41,438,666**	**$4,105,351,485**	**$4,726,059,114**	**115.1%**

SUMMARY OF ASC 715-30 VALUATION RESULTS AS OF JANUARY 1, 2014

Location	*Valuation Earnings*	*Market-Related Value of Assets*	*Fair Value of Assets*	*Accumulated Benefit Obligation*	*Projected Benefit Obligation*	*January 1, 2014 Pre-Tax AOCI*
140 Appalachian Power Co - Distribution	$84,512,632	$297,485,232	$311,905,817	$324,582,269	$328,405,056	$118,322,027
215 Appalachian Power Co - Generation	77,844,052	252,522,247	264,763,253	272,926,813	276,974,512	82,779,783
150 Appalachian Power Co - Transmission	4,800,964	29,948,625	31,400,384	38,077,411	38,259,468	16,257,932
Appalachian Power Co. - FERC	**$167,157,648**	**$579,956,104**	**$608,069,454**	**$635,586,493**	**$643,639,036**	**$217,359,742**
225 Cedar Coal Co	0	4,373,955	4,585,983	3,459,518	3,459,518	2,595,629
Appalachian Power Co. - SEC	**$167,157,648**	**$584,330,059**	**$612,655,437**	**$639,046,011**	**$647,098,554**	**$219,955,371**
211 AEP Texas Central Company - Distribution	$70,653,200	$261,731,307	$274,418,722	$271,270,951	$279,000,916	$131,503,530
147 AEP Texas Central Company - Generation	0	13,861,705	14,533,651	7,311,167	7,311,167	(7,222,484)
169 AEP Texas Central Company - Transmission	8,786,245	25,199,197	26,420,727	26,139,434	27,069,199	16,499,353
AEP Texas Central Co.	**$ 79,439,445**	**$ 300,792,209**	**$ 315,373,100**	**$ 304,721,552**	**$ 313,381,282**	**$ 140,780,399**
170 Indiana Michigan Power Co - Distribution	$47,036,673	$154,669,233	$162,166,819	$164,062,313	$167,203,867	$56,282,754
132 Indiana Michigan Power Co - Generation	33,662,402	101,474,161	106,393,117	111,027,706	112,032,380	28,967,084
190 Indiana Michigan Power Co - Nuclear	111,226,470	210,278,407	220,471,645	210,602,928	217,368,696	30,355,681
120 Indiana Michigan Power Co - Transmission	10,512,000	32,212,949	33,774,470	37,154,418	37,856,413	12,171,034
280 Ind Mich River Transp Lakin	21,755,217	35,169,308	36,874,139	32,204,002	34,240,192	4,104,557
Indiana Michigan Power Co. - FERC	**$224,192,762**	**$533,804,058**	**$559,680,190**	**$555,051,367**	**$568,701,548**	**$131,881,110**
202 Price River Coal	0	0	0	0	0	389,835
Indiana Michigan Power Co. - SEC	**$224,192,762**	**$533,804,058**	**$559,680,190**	**$555,051,367**	**$568,701,548**	**$132,270,945**
110 Kentucky Power Co - Distribution	$20,689,821	$65,223,505	$68,385,212	$72,297,234	$73,061,972	$20,093,799
117 Kentucky Power Co - Generation	7,869,114	30,018,882	31,474,046	35,232,456	35,440,721	10,746,494
180 Kentucky Power Co - Transmission	2,373,202	5,896,275	6,182,096	6,727,364	6,840,091	1,725,755
600 Kentucky Power Co. - Kammer Actives	3,372,332	5,174,881	5,425,733	5,204,952	5,291,035	3,473,585
701 Kentucky Power Co. - Mitchell Actives	21,105,325	33,871,239	35,513,146	28,796,052	29,968,723	9,817,201
702 Kentucky Power Co. - Mitchell Inactives	$0	$26,416,563	$27,697,105	$23,740,957	$23,740,957	$9,489,032
Kentucky Power Co.	**$55,409,794**	**$166,601,345**	**$174,677,338**	**$171,999,015**	**$174,343,499**	**$55,345,866**
250 Ohio Power Co - Distribution	$116,244,877	$413,652,018	$433,703,784	$427,181,120	$436,333,873	$182,275,697
160 Ohio Power Co - Transmission	879,542	41,503,861	43,515,760	48,389,591	48,419,864	31,483,029
Ohio Power Co	**$117,124,419**	**$455,155,879**	**$477,219,544**	**$475,570,711**	**$484,753,737**	**$213,758,726**
167 Public Service Co of Oklahoma - Distribution	$53,646,651	$152,967,876	$160,382,988	$154,990,426	$160,988,434	$65,152,593
198 Public Service Co of Oklahoma - Generation	32,076,137	79,452,166	83,303,607	77,163,690	80,229,161	24,692,416
114 Public Service Co of Oklahoma - Transmission	7,029,125	19,116,736	20,043,420	18,455,843	19,218,275	6,548,628
Public Service Co. of Oklahoma	**$92,751,913**	**$251,536,778**	**$263,730,015**	**$250,609,959**	**$260,435,870**	**$96,393,637**
159 Southwestern Electric Power Co - Distribution	$42,472,372	$97,061,029	$101,766,058	$92,358,579	$97,690,360	$38,583,037
168 Southwestern Electric Power Co - Generation	50,660,835	104,647,841	109,720,641	103,629,992	107,814,840	33,690,674
161 Southwestern Electric Power Co - Texas - Distribution	19,088,423	48,522,496	50,874,622	50,510,093	52,454,149	22,178,342
111 Southwestern Electric Power Co - Texas - Transmission	0	74,100	77,692	149,162	149,162	923,789
194 Southwestern Electric Power Co - Transmission	6,469,427	15,410,222	16,157,232	14,309,451	14,988,719	4,842,254
Southwestern Electric Power Co.	**$118,691,057**	**$265,715,688**	**$278,596,245**	**$260,957,277**	**$273,097,230**	**$100,218,096**
119 AEP Texas North Company - Distribution	$20,645,160	$64,277,688	$67,393,547	$66,160,245	$68,052,511	$30,710,316
166 AEP Texas North Company - Generation	0	23,570,002	24,712,557	21,294,691	21,294,691	16,645,985
192 AEP Texas North Company - Transmission	4,117,298	9,372,758	9,827,102	8,994,306	9,466,250	3,885,839
AEP Texas North Co.	**$24,762,458**	**$97,220,448**	**$101,933,206**	**$96,449,242**	**$98,813,452**	**$51,242,140**
230 Kingsport Power Co - Distribution	$3,953,378	$12,286,705	$12,882,303	$13,425,702	$13,640,456	$5,099,242
260 Kingsport Power Co - Transmission	444,453	2,147,828	2,251,944	2,741,050	2,774,811	1,388,742
Kingsport Power Co.	**$4,397,831**	**$14,434,533**	**$15,134,247**	**$16,166,752**	**$16,415,267**	**$6,487,984**
210 Wheeling Power Co - Distribution	$3,674,311	$14,845,686	$15,565,330	$15,588,079	$15,762,329	$6,868,291
200 Wheeling Power Co - Transmission	0	846,071	887,084	702,255	702,255	665,333
Wheeling Power Co.	**$3,674,311**	**$15,691,757**	**$16,452,414**	**$16,290,334**	**$16,464,584**	**$7,533,624**
103 American Electric Power Service Corporation	$499,855,502	$1,323,151,091	$1,387,290,786	$1,408,611,387	$1,448,053,663	$367,388,910
American Electric Power Service Corp	**$499,855,502**	**$1,323,151,091**	**$1,387,290,786**	**$1,408,611,387**	**$1,448,053,663**	**$367,388,910**
143 AEP Pro Serv, Inc.	$0	$967,372	$1,014,265	$1,077,850	$1,077,850	$14,188
171 CSW Energy, Inc.	10,958,535	9,253,338	9,701,893	9,195,908	10,587,705	4,118,275
293 Elmwood	4,209,151	4,834,420	5,068,769	2,794,783	3,047,933	(2,044,996)
292 AEP River Operations LLC	71,039,647	45,823,615	48,044,913	29,276,534	35,725,072	(12,315,862)
189 Central Coal Company	0	0	0	0	0	3,400,814
Miscellaneous	**$86,207,333**	**$60,878,745**	**$63,829,840**	**$42,345,075**	**$50,438,560**	**($6,827,581)**
270 Cook Coal Terminal	$1,443,667	$3,790,505	$3,974,249	$3,628,628	$3,754,790	$523,916
AEP Generating Company	**$1,443,667**	**$3,790,505**	**$3,974,249**	**$3,628,628**	**$3,754,790**	**$523,916**
104 Cardinal Operating Company	$25,622,840	$83,319,383	$87,358,287	$77,169,947	$78,530,195	($8,828,092)
181 Ohio Power Co - Generation	55,463,811	347,019,994	363,841,775	301,340,675	304,396,568	120,905,766
AEP Generation Resources - FERC	**$81,086,651**	**$430,339,377**	**$451,200,062**	**$378,510,622**	**$382,926,763**	**$112,077,674**
290 Conesville Coal Preparation Company	0	4,113,061	4,312,441	3,287,741	3,287,741	458,879
AEP Generation Resources - SEC	**$81,086,651**	**$434,452,438**	**$455,512,503**	**$381,798,363**	**$386,214,504**	**$112,536,553**
Total	**1,556,194,791**	**4,507,555,533**	**4,726,059,114**	**4,623,245,673**	**4,741,966,540**	**1,497,608,586**

Location	ASC 715-30 Cost 2014	Estimated Net Periodic Pension Cost 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
140 Appalachian Power Co - Distribution	$9,732,911	$6,902,782	$8,242,226	$6,874,665	$6,060,349	$5,653,520	$5,657,586	$5,617,293	$5,666,947	$5,671,600	$5,744,247
215 Appalachian Power Co - Generation	8,547,560	6,128,680	7,202,249	6,140,297	5,447,493	4,996,295	4,947,058	4,862,384	4,840,079	4,794,710	4,755,009
150 Appalachian Power Co - Transmission	1,198,260	874,717	815,486	568,164	464,033	395,486	417,338	396,380	416,942	395,519	401,831
Appalachian Power Co. - FERC	**19,478,731**	**13,906,179**	**16,259,961**	**13,583,126**	**11,971,875**	**11,045,301**	**11,021,982**	**10,876,057**	**10,923,968**	**10,861,829**	**10,901,087**
225 Cedar Coal Co	(9,812)	(41,632)	(30,571)	(48,336)	(58,460)	(66,614)	(69,361)	(71,897)	(74,794)	(77,751)	(80,707)
Appalachian Power Co. - SEC	**19,468,919**	**13,864,547**	**16,229,390**	**13,534,790**	**11,913,415**	**10,978,687**	**10,952,621**	**10,804,160**	**10,849,174**	**10,784,078**	**10,820,380**
211 AEP Texas Central Company - Distribution	8,985,957	6,588,713	7,852,194	6,819,786	6,341,074	6,058,144	6,147,746	6,185,493	6,303,213	6,375,528	6,466,186
147 AEP Texas Central Company - Generation	(284,812)	(387,659)	(412,038)	(471,009)	(465,740)	(477,195)	(512,836)	(525,749)	(527,135)	(559,628)	(610,760)
169 AEP Texas Central Company - Transmission	1,001,137	776,147	898,878	807,147	776,153	737,127	739,925	732,026	726,608	716,831	710,434
AEP Texas Central Co.	**9,702,282**	**6,977,201**	**8,339,034**	**7,155,924**	**6,651,487**	**6,318,076**	**6,374,835**	**6,391,770**	**6,502,686**	**6,532,731**	**6,565,860**
170 Indiana Michigan Power Co - Distribution	4,974,314	3,562,537	4,276,094	3,696,591	3,284,975	3,127,633	3,122,966	3,088,690	3,079,757	3,036,173	3,044,997
132 Indiana Michigan Power Co - Generation	3,625,910	2,607,900	3,000,620	2,559,323	2,261,124	2,054,017	2,053,385	2,014,008	2,006,216	1,990,229	2,000,609
190 Indiana Michigan Power Co - Nuclear	8,908,147	6,843,421	7,439,981	6,503,191	5,752,554	5,080,480	4,761,301	4,387,825	4,065,597	3,760,570	3,489,582
120 Indiana Michigan Power Co - Transmission	1,273,251	939,702	1,046,991	830,440	732,341	674,045	668,475	658,240	653,726	648,836	653,535
280 Ind Mich River Transp Lakin	1,304,020	1,000,344	1,095,163	950,626	814,197	709,039	655,203	609,098	550,401	484,766	408,990
Indiana Michigan Power Co. - FERC	**20,085,642**	**14,953,904**	**16,858,849**	**14,540,171**	**12,845,191**	**11,645,214**	**11,261,330**	**10,757,861**	**10,355,697**	**9,920,574**	**9,597,713**
202 Price River Coal	32	5	0	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**20,085,674**	**14,953,909**	**16,858,849**	**14,540,171**	**12,845,191**	**11,645,214**	**11,261,330**	**10,757,861**	**10,355,697**	**9,920,574**	**9,597,713**
110 Kentucky Power Co - Distribution	2,293,613	1,649,850	1,935,938	1,601,868	1,398,174	1,288,089	1,281,527	1,266,352	1,275,934	1,275,256	1,285,823
117 Kentucky Power Co - Generation	1,111,950	794,465	878,006	663,296	566,985	508,725	505,747	495,520	508,118	515,278	526,135
180 Kentucky Power Co - Transmission	273,606	207,768	226,520	192,880	169,612	154,746	149,121	140,734	134,291	126,590	119,877
600 Kentucky Power Co. - Kammer Actives	246,878	190,259	201,630	177,061	153,582	137,818	132,655	124,360	118,519	114,054	110,714
701 Kentucky Power Co. - Mitchell Actives	1,114,089	760,035	786,098	610,418	437,977	321,058	245,788	144,693	68,062	(11,971)	(97,635)
702 Kentucky Power Co. - Mitchell Inactives	150,180	(58,802)	26,571	(83,915)	(149,486)	(198,188)	(210,689)	(222,788)	(237,504)	(251,956)	(265,152)
Kentucky Power Co.	**5,190,316**	**3,543,575**	**4,054,763**	**3,161,608**	**2,576,844**	**2,212,248**	**2,104,149**	**1,948,871**	**1,867,420**	**1,767,251**	**1,679,762**
250 Ohio Power Co - Distribution	12,321,597	8,536,020	10,365,822	8,886,270	7,880,705	7,246,783	7,221,949	7,174,123	7,099,439	7,077,865	7,026,486
160 Ohio Power Co - Transmission	1,052,586	721,546	811,380	474,844	349,121	260,190	275,276	232,388	199,978	169,023	155,045
Ohio Power Co.	**13,374,183**	**9,257,566**	**11,177,202**	**9,361,114**	**8,229,826**	**7,506,973**	**7,497,225**	**7,406,511**	**7,299,417**	**7,246,888**	**7,181,531**
167 Public Service Co of Oklahoma - Distribution	5,809,449	4,384,514	5,114,363	4,576,078	4,310,017	4,180,799	4,248,957	4,174,802	4,234,739	4,180,641	4,122,981
198 Public Service Co of Oklahoma - Generation	3,036,576	2,442,716	2,815,613	2,538,388	2,384,778	2,305,913	2,330,825	2,356,850	2,359,397	2,368,245	2,347,802
114 Public Service Co of Oklahoma - Transmission	667,937	517,554	601,585	532,257	493,399	457,999	480,806	474,310	473,982	463,515	449,839
Public Service Co. of Oklahoma	**9,513,962**	**7,344,784**	**8,531,561**	**7,646,723**	**7,188,194**	**6,944,711**	**7,060,588**	**7,005,962**	**7,068,118**	**7,012,401**	**6,920,622**
159 Southwestern Electric Power Co - Distribution	3,837,615	3,048,767	3,490,051	3,130,308	2,898,868	2,827,165	2,823,935	2,776,924	2,776,332	2,756,174	2,703,853
168 Southwestern Electric Power Co - Generation	4,625,799	3,766,384	4,253,297	3,888,267	3,718,093	3,590,861	3,618,172	3,565,987	3,576,012	3,539,325	3,500,153
161 Southwestern Electric Power Co - Texas - Distribution	2,078,358	1,653,515	1,923,082	1,681,416	1,622,639	1,566,608	1,569,226	1,567,223	1,551,685	1,546,493	1,529,490
111 Southwestern Electric Power Co - Texas - Transmissio	6,099	5,823	2,675	1,587	1,204	864	837	677	547	407	329
194 Southwestern Electric Power Co - Transmission	537,230	420,737	491,826	436,448	395,805	370,754	360,706	337,688	319,015	293,905	267,917
Southwestern Electric Power Co.	**11,085,101**	**8,895,226**	**10,160,931**	**9,138,026**	**8,636,609**	**8,356,252**	**8,372,876**	**8,248,499**	**8,223,591**	**8,136,304**	**8,001,742**
119 AEP Texas North Company - Distribution	2,397,004	1,930,717	2,258,848	1,973,479	1,865,566	1,799,561	1,876,924	1,879,102	1,893,896	1,901,005	1,905,655
166 AEP Texas North Company - Generation	141,758	(46,286)	31,724	(44,520)	(88,340)	(120,491)	(119,676)	(116,836)	(118,665)	(110,854)	(117,694)
192 AEP Texas North Company - Transmission	379,445	293,290	328,644	284,144	282,575	272,020	275,565	273,250	272,454	263,805	278,831
AEP Texas North Co.	**2,918,207**	**2,177,721**	**2,619,216**	**2,213,103**	**2,059,801**	**1,951,090**	**2,032,813**	**2,035,516**	**2,047,685**	**2,053,956**	**2,066,792**
230 Kingsport Power Co - Distribution	444,947	322,943	375,928	317,611	282,969	260,262	256,611	248,626	245,098	238,339	241,219
260 Kingsport Power Co - Transmission	91,691	70,561	64,661	47,681	40,603	35,345	35,036	34,447	34,183	34,368	33,460
Kingsport Power Co.	**536,638**	**393,504**	**440,589**	**365,292**	**323,572**	**295,607**	**291,647**	**283,073**	**279,281**	**272,707**	**274,679**
210 Wheeling Power Co - Distribution	458,837	323,390	387,538	333,094	293,084	271,278	276,546	273,492	272,930	276,820	276,424
200 Wheeling Power Co - Transmission	(226)	(4,772)	(534)	(2,094)	(2,282)	(2,233)	(1,283)	(471)	88	439	598
Wheeling Power Co.	**458,611**	**318,618**	**387,004**	**331,000**	**290,802**	**269,045**	**275,263**	**273,021**	**273,018**	**277,259**	**277,022**
103 American Electric Power Service Corporation	48,004,650	34,995,903	40,429,476	34,921,358	31,145,924	28,752,143	28,246,902	27,559,850	27,121,096	26,646,509	26,276,483
American Electric Power Service Corp	**48,004,650**	**34,995,903**	**40,429,476**	**34,921,358**	**31,145,924**	**28,752,143**	**28,246,902**	**27,559,850**	**27,121,096**	**26,646,509**	**26,276,483**
143 AEP Pro Serv, Inc.	20,377	11,260	15,416	9,332	6,327	2,798	868	(961)	(3,114)	(4,626)	(5,146)
171 CSW Energy, Inc.	757,079	623,762	641,909	584,162	555,037	500,698	452,893	398,312	348,625	287,819	228,180
293 Elmwood	195,640	167,795	172,980	159,746	140,253	120,781	107,087	87,722	66,323	40,373	16,840
189 Central Coal Company	0	0	0	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	3,943,710	3,629,440	3,733,732	3,668,794	3,471,180	3,278,906	3,077,404	2,764,756	2,529,562	2,208,383	1,859,844
Miscellaneous	**4,916,806**	**4,432,257**	**4,564,037**	**4,422,034**	**4,172,797**	**3,903,183**	**3,638,252**	**3,249,829**	**2,941,396**	**2,531,949**	**2,099,718**
270 Cook Coal Terminal	130,718	96,142	107,360	93,812	83,322	74,790	74,178	71,843	68,546	65,230	60,141
AEP Generating Company	**130,718**	**96,142**	**107,360**	**93,812**	**83,322**	**74,790**	**74,178**	**71,843**	**68,546**	**65,230**	**60,141**
104 Cardinal Operating Company	1,905,828	1,183,831	1,428,711	1,078,315	836,220	651,978	569,583	474,082	399,804	320,214	231,042
181 Ohio Power Co - Generation	4,148,137	1,362,526	2,247,275	832,259	(80,751)	(786,077)	(1,035,932)	(1,382,426)	(1,655,354)	(2,026,341)	(2,355,393)
AEP Generation Resources - FERC	**6,053,965**	**2,546,357**	**3,675,986**	**1,910,574**	**755,469**	**(134,099)**	**(466,349)**	**(908,344)**	**(1,255,550)**	**(1,706,127)**	**(2,124,351)**
290 Conesville Coal Preparation Company	(6,515)	(36,136)	(23,905)	(39,913)	(51,272)	(60,292)	(63,930)	(67,139)	(72,654)	(80,201)	(87,744)
AEP Generation Resources - SEC	**6,047,450**	**2,510,221**	**3,652,081**	**1,870,661**	**704,197**	**(194,391)**	**(530,279)**	**(975,483)**	**(1,328,204)**	**(1,786,328)**	**(2,212,095)**
Total	**$151,433,517**	**$109,761,174**	**$127,551,493**	**$108,755,616**	**$96,821,981**	**$89,013,628**	**$87,652,400**	**$85,061,283**	**$83,568,921**	**$81,461,509**	**$79,610,350**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
2014 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$328,405,056	$297,485,232	$3,484,074	$15,012,514	($17,272,111)	$95,769	$8,412,665	$9,732,911
215 Appalachian Power Co - Generation	276,974,512	252,522,247	3,337,610	12,687,762	(14,661,543)	88,548	7,095,183	8,547,560
150 Appalachian Power Co - Transmission	38,259,468	29,948,625	197,061	1,746,686	(1,738,829)	13,259	980,083	1,198,260
Appalachian Power Co. - FERC	**$643,639,036**	**$579,956,104**	**$7,018,745**	**$29,446,962**	**($33,672,483)**	**$197,576**	**$16,487,931**	**$19,478,731**
225 Cedar Coal Co	3,459,518	4,373,955	0	155,264	(253,954)	256	88,622	(9,812)
Appalachian Power Co. - SEC	**$647,098,554**	**$584,330,059**	**$7,018,745**	**$29,602,226**	**($33,926,437)**	**$197,832**	**$16,576,553**	**$19,468,919**
211 AEP Texas Central Company - Distribution	$279,000,916	$261,731,307	$4,001,121	$12,743,770	($15,196,224)	$290,197	$7,147,093	$8,985,957
147 AEP Texas Central Company - Generation	7,311,167	13,861,705	0	332,716	(804,816)	0	187,288	(284,812)
169 AEP Texas Central Company - Transmission	27,069,199	25,199,197	500,409	1,238,193	(1,463,075)	32,185	693,425	1,001,137
AEP Texas Central Co.	**$313,381,282**	**$300,792,209**	**$4,501,530**	**$14,314,679**	**($17,464,115)**	**$322,382**	**$8,027,806**	**$9,702,282**
170 Indiana Michigan Power Co - Distribution	$167,203,867	$154,669,233	$1,987,533	$7,633,937	($8,980,157)	$49,784	$4,283,217	$4,974,314
132 Indiana Michigan Power Co - Generation	112,032,380	101,474,161	1,463,138	5,152,341	(5,891,630)	32,157	2,869,904	3,625,910
190 Indiana Michigan Power Co - Nuclear	217,368,696	210,278,407	5,311,540	10,151,275	(12,208,848)	85,904	5,568,276	8,908,147
120 Indiana Michigan Power Co - Transmission	37,856,413	32,212,949	425,845	1,737,237	(1,870,297)	10,708	969,758	1,273,251
280 Ind Mich River Transp Lakin	34,240,192	35,169,308	856,192	1,595,825	(2,041,944)	16,825	877,122	1,304,020
Indiana Michigan Power Co. - FERC	**$568,701,548**	**$533,804,058**	**$10,044,248**	**$26,270,615**	**($30,992,876)**	**$195,378**	**$14,568,277**	**$20,085,642**
202 Price River Coal	0	0	0	0	0	32	0	32
Indiana Michigan Power Co. - SEC	**$568,701,548**	**$533,804,058**	**$10,044,248**	**$26,270,615**	**($30,992,876)**	**$195,410**	**$14,568,277**	**$20,085,674**
110 Kentucky Power Co - Distribution	$73,061,972	$65,223,505	$835,000	$3,349,713	($3,786,903)	$24,194	$1,871,609	$2,293,613
117 Kentucky Power Co - Generation	35,440,721	30,018,882	307,728	1,626,354	(1,742,908)	12,900	907,876	1,111,950
180 Kentucky Power Co - Transmission	6,840,091	5,896,275	119,495	317,369	(342,340)	3,861	175,221	273,606
600 Kentucky Power Co. - Kammer Actives	5,291,035	5,174,881	158,964	251,077	(300,456)	1,754	135,539	246,878
701 Kentucky Power Co. - Mitchell Actives	29,968,723	33,871,239	877,776	1,427,475	(1,966,578)	7,715	767,701	1,114,089
702 Kentucky Power Co. - Mitchell Inactives	23,740,957	26,416,563	0	1,069,343	(1,533,756)	6,427	608,166	150,180
Kentucky Power Co.	**$174,343,499**	**$166,601,345**	**$2,298,963**	**$8,041,331**	**($9,672,941)**	**$56,851**	**$4,466,112**	**$5,190,316**
250 Ohio Power Co - Distribution	$436,333,873	$413,652,018	$5,102,236	$19,927,019	($24,016,801)	$131,694	$11,177,449	$12,321,597
160 Ohio Power Co - Transmission	48,419,864	41,503,861	24,782	2,171,890	(2,409,731)	25,286	1,240,359	1,052,586
Ohio Power Co.	**$484,753,737**	**$455,155,879**	**$5,127,018**	**$22,098,909**	**($26,426,532)**	**$156,980**	**$12,417,808**	**$13,374,183**
167 Public Service Co of Oklahoma - Distribution	$160,988,434	$152,967,876	$3,000,746	$7,383,422	($8,881,376)	$182,659	$4,123,998	$5,809,449
198 Public Service Co of Oklahoma - Generation	80,229,161	79,452,166	1,817,328	3,684,008	(4,613,024)	93,055	2,055,209	3,036,576
114 Public Service Co of Oklahoma - Transmission	19,218,275	19,116,736	380,791	882,109	(1,109,925)	22,653	492,309	667,937
Public Service Co. of Oklahoma	**$260,435,870**	**$251,536,778**	**$5,198,865**	**$11,949,539**	**($14,604,325)**	**$298,367**	**$6,671,516**	**$9,513,962**
159 Southwestern Electric Power Co - Distribution	$97,690,360	$97,061,029	$2,331,507	$4,510,429	($5,635,402)	$128,573	$2,502,508	$3,837,615
168 Southwestern Electric Power Co - Generation	107,814,840	104,647,841	2,829,007	4,977,118	(6,075,895)	133,705	2,761,864	4,625,799
161 Southwestern Electric Power Co - Texas - Distribution	52,454,149	48,522,496	1,086,188	2,399,321	(2,817,236)	66,381	1,343,704	2,078,358
111 Southwestern Electric Power Co - Texas - Transmission	149,162	74,100	0	6,477	(4,302)	103	3,821	6,099
194 Southwestern Electric Power Co - Transmission	14,988,719	15,410,222	337,799	688,507	(894,724)	21,686	383,962	537,230
Southwestern Electric Power Co.	**$273,097,230**	**$265,715,688**	**$6,584,501**	**$12,581,852**	**($15,427,559)**	**$350,448**	**$6,995,859**	**$11,085,101**
119 AEP Texas North Company - Distribution	68,052,511	64,277,688	1,214,724	3,081,845	(3,731,988)	89,140	1,743,283	2,397,004
166 AEP Texas North Company - Generation	21,294,691	23,570,002	0	957,267	(1,368,484)	7,475	545,500	141,758
192 AEP Texas North Company - Transmission	9,466,250	9,372,758	228,142	440,542	(544,186)	12,453	242,494	379,445
AEP Texas North Co.	**$98,813,452**	**$97,220,448**	**$1,442,866**	**$4,479,654**	**($5,644,658)**	**$109,068**	**$2,531,277**	**$2,918,207**
230 Kingsport Power Co - Distribution	$13,640,456	$12,286,705	$178,862	$626,422	($713,371)	$3,610	$349,424	$444,947
260 Kingsport Power Co - Transmission	2,774,811	2,147,828	18,754	125,997	(124,704)	562	71,082	91,691
Kingsport Power Co.	**$16,415,267**	**$14,434,533**	**$197,616**	**$752,419**	**($838,075)**	**$4,172**	**$420,506**	**$536,638**
210 Wheeling Power Co - Distribution	$15,762,329	$14,845,686	$190,484	$720,107	($861,946)	$6,413	$403,779	$458,837
200 Wheeling Power Co - Transmission	702,255	846,071	0	30,855	(49,123)	53	17,989	(226)
Wheeling Power Co.	**$16,464,584**	**$15,691,757**	**$190,484**	**$750,962**	**($911,069)**	**$6,466**	**$421,768**	**$458,611**
103 American Electric Power Service Corporation	$1,448,053,663	$1,323,151,091	$20,540,697	$66,541,695	($76,822,680)	$650,533	$37,094,405	$48,004,650
American Electric Power Service Corp	**$1,448,053,663**	**$1,323,151,091**	**$20,540,697**	**$66,541,695**	**($76,822,680)**	**$650,533**	**$37,094,405**	**$48,004,650**
143 AEP Pro Serv, Inc.	$1,077,850	$967,372	$0	$48,890	($56,166)	$42	$27,611	$20,377
171 CSW Energy, Inc.	10,587,705	9,253,338	506,837	512,634	(537,253)	3,639	271,222	757,079
293 Elmwood	3,047,933	4,834,420	243,647	147,881	(280,688)	6,722	78,078	195,640
292 AEP River Operations LLC	35,725,072	45,823,615	3,852,656	1,798,832	(2,660,537)	37,599	915,160	3,943,710
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$50,438,560**	**$60,878,745**	**$4,603,140**	**$2,508,237**	**($3,534,644)**	**$48,002**	**$1,292,071**	**$4,916,806**
270 Cook Coal Terminal	$3,754,790	$3,790,505	$79,089	$174,559	($220,078)	$963	$96,185	$130,718
AEP Generating Company	**$3,754,790**	**$3,790,505**	**$79,089**	**$174,559**	**($220,078)**	**$963**	**$96,185**	**$130,718**
104 Cardinal Operating Company	$78,530,195	$83,319,383	$1,098,547	$3,614,275	($4,837,557)	$18,876	$2,011,687	$1,905,828
181 Ohio Power Co - Generation	304,396,568	347,019,994	2,537,323	13,872,781	(20,148,119)	88,506	7,797,646	4,148,137
AEP Generation Resources - FERC	**$382,926,763**	**$430,339,377**	**$3,635,870**	**$17,487,056**	**($24,985,676)**	**$107,382**	**$9,809,333**	**$6,053,965**
290 Conesville Coal Preparation Company	3,287,741	4,113,061	0	147,365	(238,806)	705	84,221	(6,515)
AEP Generation Resources - SEC	**$386,214,504**	**$434,452,438**	**$3,635,870**	**$17,634,421**	**($25,224,482)**	**$108,087**	**$9,893,554**	**$6,047,450**
Total	**$4,741,966,540**	**$4,507,555,533**	**$71,463,632**	**$217,701,098**	**($261,710,471)**	**$2,505,561**	**$121,473,697**	**$151,433,517**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2015 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$305,096,427	$302,549,254	$3,568,911	$15,714,899	($17,592,600)	$86,250	$5,125,322	$6,902,782
215 Appalachian Power Co - Generation	257,316,178	257,806,555	3,418,881	13,296,178	(14,990,906)	81,866	4,322,661	6,128,680
150 Appalachian Power Co - Transmission	35,543,993	30,176,594	201,859	1,818,327	(1,754,705)	12,132	597,104	874,717
Appalachian Power Co. - FERC	**$597,956,598**	**$590,532,403**	**$7,189,651**	**$30,829,404**	**($34,338,211)**	**$180,248**	**$10,045,087**	**$13,906,179**
225 Cedar Coal Co	3,213,978	4,437,999	0	162,393	(258,060)	43	53,992	(41,632)
Appalachian Power Co. - SEC	**$601,170,576**	**$594,970,402**	**$7,189,651**	**$30,991,797**	**($34,596,271)**	**$180,291**	**$10,099,079**	**$13,864,547**
211 AEP Texas Central Company - Distribution	$259,198,758	$265,571,093	$4,098,548	$13,340,700	($15,442,398)	$237,577	$4,354,286	$6,588,713
147 AEP Texas Central Company - Generation	6,792,255	14,616,330	0	348,147	(849,909)	0	114,103	(387,659)
169 AEP Texas Central Company - Transmission	25,147,956	25,546,430	512,594	1,299,612	(1,485,471)	26,951	422,461	776,147
AEP Texas Central Co.	**$291,138,969**	**$305,733,853**	**$4,611,142**	**$14,988,459**	**($17,777,778)**	**$264,528**	**$4,890,850**	**$6,977,201**
170 Indiana Michigan Power Co - Distribution	$155,336,532	$156,943,446	$2,035,929	$7,998,196	($9,125,930)	$44,840	$2,609,502	$3,562,537
132 Indiana Michigan Power Co - Generation	104,080,854	104,372,506	1,498,765	5,400,168	(6,069,041)	29,551	1,748,457	2,607,900
190 Indiana Michigan Power Co - Nuclear	201,940,900	218,874,152	5,440,876	10,655,338	(12,727,069)	81,866	3,392,410	6,843,421
120 Indiana Michigan Power Co - Transmission	35,169,545	32,891,089	436,214	1,815,459	(1,912,547)	9,762	590,814	939,702
280 Ind Mich River Transp Lakin	31,809,986	36,165,821	877,040	1,675,892	(2,102,966)	16,001	534,377	1,000,344
Indiana Michigan Power Co. - FERC	**$528,337,817**	**$549,247,014**	**$10,288,824**	**$27,545,053**	**($31,937,553)**	**$182,020**	**$8,875,560**	**$14,953,904**
202 Price River Coal	0	0	0	0	0	5	0	5
Indiana Michigan Power Co. - SEC	**$528,337,817**	**$549,247,014**	**$10,288,824**	**$27,545,053**	**($31,937,553)**	**$182,025**	**$8,875,560**	**$14,953,909**
110 Kentucky Power Co - Distribution	$67,876,381	$66,655,876	$855,332	$3,507,623	($3,875,898)	$22,536	$1,140,257	$1,649,850
117 Kentucky Power Co - Generation	32,925,307	30,710,518	315,221	1,699,800	(1,785,752)	12,083	553,113	794,465
180 Kentucky Power Co - Transmission	6,354,614	6,148,520	122,405	332,434	(357,523)	3,701	106,751	207,768
600 Kentucky Power Co. - Kammer Actives	4,915,502	5,482,518	162,835	262,064	(318,797)	1,581	82,576	190,259
701 Kentucky Power Co. - Mitchell Actives	27,841,686	36,162,172	899,150	1,488,975	(2,102,754)	6,951	467,713	760,035
702 Kentucky Power Co. - Mitchell Inactives	22,055,937	26,705,264	0	1,117,744	(1,552,855)	5,791	370,518	(58,802)
Kentucky Power Co.	**$161,969,427**	**$171,864,868**	**$2,354,943**	**$8,408,640**	**($9,993,579)**	**$52,643**	**$2,720,928**	**$3,543,575**
250 Ohio Power Co - Distribution	$405,364,969	$420,799,602	$5,226,476	$20,851,271	($24,468,608)	$117,145	$6,809,736	$8,536,020
160 Ohio Power Co - Transmission	44,983,252	40,559,995	25,385	2,275,919	(2,358,478)	23,045	755,675	721,546
Ohio Power Co.	**$450,348,221**	**$461,359,597**	**$5,251,861**	**$23,127,190**	**($26,827,086)**	**$140,190**	**$7,565,411**	**$9,257,566**
167 Public Service Co of Oklahoma - Distribution	$149,562,240	$156,164,417	$3,073,814	$7,726,161	($9,080,631)	$152,670	$2,512,500	$4,384,514
198 Public Service Co of Oklahoma - Generation	74,534,877	79,394,834	1,861,580	3,864,925	(4,616,642)	80,740	1,252,113	2,442,716
114 Public Service Co of Oklahoma - Transmission	17,854,253	19,192,769	390,063	924,173	(1,116,019)	19,403	299,934	517,554
Public Service Co. of Oklahoma	**$241,951,370**	**$254,752,020**	**$5,325,457**	**$12,515,259**	**($14,813,292)**	**$252,813**	**$4,064,547**	**$7,344,784**
159 Southwestern Electric Power Co - Distribution	$90,756,763	$97,905,731	$2,388,279	$4,716,405	($5,693,011)	$112,469	$1,524,625	$3,048,767
168 Southwestern Electric Power Co - Generation	100,162,655	105,819,396	2,897,893	5,220,527	(6,153,174)	118,503	1,682,635	3,766,384
161 Southwestern Electric Power Co - Texas - Distribution	48,731,203	49,076,220	1,112,637	2,517,608	(2,853,678)	58,311	818,637	1,653,515
111 Southwestern Electric Power Co - Texas - Transmission	138,575	56,867	0	6,791	(3,307)	11	2,328	5,823
194 Southwestern Electric Power Co - Transmission	13,924,891	15,464,993	346,024	720,725	(899,257)	19,320	233,925	420,737
Southwestern Electric Power Co.	**$253,714,087**	**$268,323,207**	**$6,744,833**	**$13,182,056**	**($15,602,427)**	**$308,614**	**$4,262,150**	**$8,895,226**
119 AEP Texas North Company - Distribution	63,222,467	63,880,354	1,244,303	3,261,209	(3,714,508)	77,637	1,062,076	1,930,717
166 AEP Texas North Company - Generation	19,783,295	23,733,160	0	999,942	(1,380,033)	1,465	332,340	(46,286)
192 AEP Texas North Company - Transmission	8,794,381	9,603,174	233,697	459,447	(558,404)	10,813	147,737	293,290
AEP Texas North Co.	**$91,800,143**	**$97,216,688**	**$1,478,000**	**$4,720,598**	**($5,652,945)**	**$89,915**	**$1,542,153**	**$2,177,721**
230 Kingsport Power Co - Distribution	$12,672,321	$12,592,337	$183,217	$655,824	($732,218)	$3,237	$212,883	$322,943
260 Kingsport Power Co - Transmission	2,577,868	2,128,172	19,211	131,302	(123,749)	491	43,306	70,561
Kingsport Power Co.	**$15,250,189**	**$14,720,509**	**$202,428**	**$787,126**	**($855,967)**	**$3,728**	**$256,189**	**$393,504**
210 Wheeling Power Co - Distribution	$14,643,594	$15,101,507	$195,122	$754,491	($878,121)	$5,900	$245,998	$323,390
200 Wheeling Power Co - Transmission	652,412	825,711	0	32,272	(48,013)	9	10,960	(4,772)
Wheeling Power Co.	**$15,296,006**	**$15,927,218**	**$195,122**	**$786,763**	**($926,134)**	**$5,909**	**$256,958**	**$318,618**
103 American Electric Power Service Corporation	$1,345,277,699	$1,357,978,133	$21,040,864	$69,726,723	($78,963,559)	$592,526	$22,599,349	$34,995,903
American Electric Power Service Corp	**$1,345,277,699**	**$1,357,978,133**	**$21,040,864**	**$69,726,723**	**($78,963,559)**	**$592,526**	**$22,599,349**	**$34,995,903**
143 AEP Pro Serv, Inc.	$1,001,349	$974,948	$0	$51,089	($56,691)	$40	$16,822	$11,260
171 CSW Energy, Inc.	9,836,240	10,361,187	519,178	538,764	(602,481)	3,062	165,239	623,762
293 Elmwood	2,831,605	5,032,185	249,580	156,557	(292,611)	6,701	47,568	167,795
292 AEP River Operations LLC	33,189,476	48,297,149	3,946,468	1,896,267	(2,808,377)	37,531	557,551	3,629,440
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$46,858,670**	**$64,665,469**	**$4,715,226**	**$2,642,677**	**($3,760,160)**	**$47,334**	**$787,180**	**$4,432,257**
270 Cook Coal Terminal	$3,488,293	$3,901,148	$81,015	$182,484	($226,844)	$887	$58,600	$96,142
AEP Generating Company	**$3,488,293**	**$3,901,148**	**$81,015**	**$182,484**	**($226,844)**	**$887**	**$58,600**	**$96,142**
104 Cardinal Operating Company	$72,956,495	$85,365,972	$1,125,297	$3,779,645	($4,963,851)	$17,142	$1,225,598	$1,183,831
181 Ohio Power Co - Generation	282,791,947	354,114,255	2,599,107	14,524,044	(20,590,996)	79,742	4,750,629	1,362,526
AEP Generation Resources - FERC	**$355,748,442**	**$439,480,227**	**$3,724,404**	**$18,303,689**	**($25,554,847)**	**$96,884**	**$5,976,227**	**$2,546,357**
290 Conesville Coal Preparation Company	3,054,393	4,161,525	0	153,908	(241,984)	629	51,311	(36,136)
AEP Generation Resources - SEC	**$358,802,835**	**$443,641,752**	**$3,724,404**	**$18,457,597**	**($25,796,831)**	**$97,513**	**$6,027,538**	**$2,510,221**
Total	**$4,405,404,302**	**$4,604,301,878**	**$73,203,770**	**$228,062,422**	**($267,730,426)**	**$2,218,916**	**$74,006,492**	**$109,761,174**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2016 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$313,684,728	$304,205,021	$3,760,647	$16,782,409	($17,693,841)	$84,048	$5,308,963	$8,242,226
215 Appalachian Power Co - Generation	264,559,490	260,599,424	3,602,557	14,199,586	(15,157,556)	80,120	4,477,542	7,202,249
150 Appalachian Power Co - Transmission	36,544,537	33,926,142	212,704	1,945,696	(1,973,287)	11,874	618,499	815,486
Appalachian Power Co. - FERC	**$614,788,755**	**$598,730,587**	**$7,575,908**	**$32,927,691**	**($34,824,684)**	**$176,042**	**$10,405,004**	**$16,259,961**
225 Cedar Coal Co	3,304,450	4,474,238	0	173,743	(260,240)	0	55,926	(30,571)
Appalachian Power Co. - SEC	**$618,093,205**	**$603,204,825**	**$7,575,908**	**$33,101,434**	**($35,084,924)**	**$176,042**	**$10,460,930**	**$16,229,390**
211 AEP Texas Central Company - Distribution	$266,495,064	$265,985,028	$4,318,739	$14,263,243	($15,470,806)	$230,717	$4,510,301	$7,852,194
147 AEP Texas Central Company - Generation	6,983,453	15,302,241	0	359,813	(890,043)	0	118,192	(412,038)
169 AEP Texas Central Company - Transmission	25,855,857	25,641,284	540,133	1,386,270	(1,491,405)	26,282	437,598	898,878
AEP Texas Central Co.	**$299,334,374**	**$306,928,553**	**$4,858,872**	**$16,009,326**	**($17,852,254)**	**$256,999**	**$5,066,091**	**$8,339,034**
170 Indiana Michigan Power Co - Distribution	$159,709,172	$157,641,981	$2,145,308	$8,553,495	($9,169,119)	$43,409	$2,703,001	$4,276,094
132 Indiana Michigan Power Co - Generation	107,010,674	106,243,941	1,579,285	5,760,948	(6,179,594)	28,877	1,811,104	3,000,620
190 Indiana Michigan Power Co - Nuclear	207,625,428	227,816,314	5,733,182	11,363,421	(13,250,753)	80,170	3,513,961	7,439,981
120 Indiana Michigan Power Co - Transmission	36,159,549	33,930,833	459,649	1,939,406	(1,973,560)	9,513	611,983	1,046,991
280 Ind Mich River Transp Lakin	32,705,420	37,583,302	924,158	1,787,982	(2,186,003)	15,502	553,524	1,095,163
Indiana Michigan Power Co. - FERC	**$543,210,243**	**$563,216,371**	**$10,841,582**	**$29,405,252**	**($32,759,029)**	**$177,471**	**$9,193,573**	**$16,858,849**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$543,210,243**	**$563,216,371**	**$10,841,582**	**$29,405,252**	**($32,759,029)**	**$177,471**	**$9,193,573**	**$16,858,849**
110 Kentucky Power Co - Distribution	$69,787,065	$67,352,483	$901,284	$3,748,899	($3,917,503)	$22,145	$1,181,113	$1,935,938
117 Kentucky Power Co - Generation	33,852,137	31,883,927	332,156	1,815,570	(1,854,503)	11,852	572,931	878,006
180 Kentucky Power Co - Transmission	6,533,493	6,379,924	128,981	354,407	(371,083)	3,639	110,576	226,520
600 Kentucky Power Co. - Kammer Actives	5,053,871	5,783,091	171,583	279,347	(336,369)	1,535	85,534	201,630
701 Kentucky Power Co. - Mitchell Actives	28,625,415	38,477,842	947,456	1,585,454	(2,238,033)	6,750	484,471	786,098
702 Kentucky Power Co. - Mitchell Inactives	22,676,800	26,789,027	0	1,195,316	(1,558,162)	5,623	383,794	26,571
Kentucky Power Co.	**$166,528,781**	**$176,666,294**	**$2,481,460**	**$8,978,993**	**($10,275,653)**	**$51,544**	**$2,818,419**	**$4,054,763**
250 Ohio Power Co - Distribution	$416,775,776	$422,791,748	$5,507,263	$22,283,069	($24,591,343)	$113,103	$7,053,730	$10,365,822
160 Ohio Power Co - Transmission	46,249,506	42,208,752	26,749	2,434,541	(2,455,038)	22,377	782,751	811,380
Ohio Power Co.	**$463,025,282**	**$465,000,500**	**$5,534,012**	**$24,717,610**	**($27,046,381)**	**$135,480**	**$7,836,481**	**$11,177,202**
167 Public Service Co of Oklahoma - Distribution	$153,772,337	$156,913,080	$3,238,952	$8,251,431	($9,126,723)	$148,180	$2,602,523	$5,114,363
198 Public Service Co of Oklahoma - Generation	76,632,994	80,076,128	1,961,591	4,135,431	(4,657,564)	79,178	1,296,977	2,815,613
114 Public Service Co of Oklahoma - Transmission	18,356,841	19,370,875	411,019	987,620	(1,126,691)	18,956	310,681	601,585
Public Service Co. of Oklahoma	**$248,762,172**	**$256,360,083**	**$5,611,562**	**$13,374,482**	**($14,910,978)**	**$246,314**	**$4,210,181**	**$8,531,561**
159 Southwestern Electric Power Co - Distribution	$93,311,517	$99,095,490	$2,516,587	$5,047,828	($5,763,810)	$110,193	$1,579,253	$3,490,051
168 Southwestern Electric Power Co - Generation	102,982,180	107,251,312	3,053,580	5,578,710	(6,238,187)	116,270	1,742,924	4,253,297
161 Southwestern Electric Power Co - Texas - Distribution	50,102,960	49,055,006	1,172,412	2,698,682	(2,853,245)	57,264	847,969	1,923,082
111 Southwestern Electric Power Co - Texas - Transmission	142,476	121,170	0	7,312	(7,048)	0	2,411	2,675
194 Southwestern Electric Power Co - Transmission	14,316,869	15,591,771	364,614	772,804	(906,883)	18,985	242,306	491,826
Southwestern Electric Power Co.	**$260,856,002**	**$271,114,749**	**$7,107,193**	**$14,105,336**	**($15,769,173)**	**$302,712**	**$4,414,863**	**$10,160,931**
119 AEP Texas North Company - Distribution	65,002,146	63,905,083	1,311,151	3,488,363	(3,716,988)	76,192	1,100,130	2,258,848
166 AEP Texas North Company - Generation	20,340,184	23,686,933	0	1,064,447	(1,377,731)	760	344,248	31,724
192 AEP Texas North Company - Transmission	9,041,938	9,820,669	246,252	489,954	(571,211)	10,619	153,030	328,644
AEP Texas North Co.	**$94,384,268**	**$97,412,685**	**$1,557,403**	**$5,042,764**	**($5,665,930)**	**$87,571**	**$1,597,408**	**$2,619,216**
230 Kingsport Power Co - Distribution	$13,029,040	$12,744,278	$193,060	$700,473	($741,261)	$3,146	$220,510	$375,928
260 Kingsport Power Co - Transmission	2,650,434	2,432,180	20,243	140,556	(141,466)	471	44,857	64,661
Kingsport Power Co.	**$15,679,474**	**$15,176,458**	**$213,303**	**$841,029**	**($882,727)**	**$3,617**	**$265,367**	**$440,589**
210 Wheeling Power Co - Distribution	$15,055,803	$15,207,253	$205,605	$805,879	($884,518)	$5,760	$254,812	$387,538
200 Wheeling Power Co - Transmission	670,777	799,759	0	34,630	(46,517)	0	11,353	(534)
Wheeling Power Co.	**$15,726,580**	**$16,007,012**	**$205,605**	**$840,509**	**($931,035)**	**$5,760**	**$266,165**	**$387,004**
103 American Electric Power Service Corporation	$1,383,146,545	$1,378,030,795	$22,171,262	$74,428,731	($80,152,054)	$572,446	$23,409,091	$40,429,476
American Electric Power Service Corp	**$1,383,146,545**	**$1,378,030,795**	**$22,171,262**	**$74,428,731**	**($80,152,054)**	**$572,446**	**$23,409,091**	**$40,429,476**
143 AEP Pro Serv, Inc.	$1,029,536	$973,557	$0	$54,579	($56,626)	$39	$17,424	$15,416
171 CSW Energy, Inc.	10,113,125	11,252,626	547,071	575,230	(654,500)	2,948	171,160	641,909
293 Elmwood	2,911,313	5,389,306	262,988	167,672	(313,465)	6,512	49,273	172,980
292 AEP River Operations LLC	34,123,742	52,848,816	4,158,488	2,035,163	(3,073,909)	36,462	577,528	3,733,732
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$48,177,716**	**$70,464,305**	**$4,968,547**	**$2,832,644**	**($4,098,500)**	**$45,961**	**$815,385**	**$4,564,037**
270 Cook Coal Terminal	$3,586,487	$4,018,172	$85,367	$194,136	($233,714)	$871	$60,700	$107,360
AEP Generating Company	**$3,586,487**	**$4,018,172**	**$85,367**	**$194,136**	**($233,714)**	**$871**	**$60,700**	**$107,360**
104 Cardinal Operating Company	$75,010,181	$87,329,105	$1,185,752	$4,036,141	($5,079,427)	$16,734	$1,269,511	$1,428,711
181 Ohio Power Co - Generation	290,752,389	360,647,812	2,738,741	15,487,044	(20,976,791)	77,436	4,920,845	2,247,275
AEP Generation Resources - FERC	**$365,762,570**	**$447,976,917**	**$3,924,493**	**$19,523,185**	**($26,056,218)**	**$94,170**	**$6,190,356**	**$3,675,986**
290 Conesville Coal Preparation Company	3,140,373	4,174,845	0	165,159	(242,827)	614	53,149	(23,905)
AEP Generation Resources - SEC	**$368,902,943**	**$452,151,762**	**$3,924,493**	**$19,688,344**	**($26,299,045)**	**$94,784**	**$6,243,505**	**$3,652,081**
Total	**$4,529,414,072**	**$4,675,752,564**	**$77,136,569**	**$243,560,590**	**($271,961,397)**	**$2,157,572**	**$76,658,159**	**$127,551,493**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2017 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$307,888,278	$309,227,507	$4,108,964	$16,788,780	($17,994,415)	$78,793	$3,892,543	$6,874,665
215 Appalachian Power Co - Generation	259,670,806	263,671,681	3,936,231	14,190,482	(15,343,453)	74,093	3,282,944	6,140,297
150 Appalachian Power Co - Transmission	35,869,246	35,652,757	232,405	1,945,543	(2,074,688)	11,419	453,485	568,164
Appalachian Power Co. - FERC	**$603,428,330**	**$608,551,945**	**$8,277,600**	**$32,924,805**	**($35,412,556)**	**$164,305**	**$7,628,972**	**$13,583,126**
225 Cedar Coal Co	3,243,388	4,518,555	0	173,601	(262,942)	0	41,005	(48,336)
Appalachian Power Co. - SEC	**$606,671,718**	**$613,070,500**	**$8,277,600**	**$33,098,406**	**($35,675,498)**	**$164,305**	**$7,669,977**	**$13,534,790**
211 AEP Texas Central Company - Distribution	$261,570,612	$266,270,148	$4,718,747	$14,256,412	($15,494,662)	$32,327	$3,306,962	$6,819,786
147 AEP Texas Central Company - Generation	6,854,409	15,573,515	0	348,579	(906,246)	0	86,658	(471,009)
169 AEP Texas Central Company - Transmission	25,378,078	25,668,951	590,160	1,385,967	(1,493,715)	3,887	320,848	807,147
AEP Texas Central Co.	**$293,803,099**	**$307,512,614**	**$5,308,907**	**$15,990,958**	**($17,894,623)**	**$36,214**	**$3,714,468**	**$7,155,924**
170 Indiana Michigan Power Co - Distribution	$156,757,973	$158,462,778	$2,344,009	$8,554,804	($9,221,188)	$37,120	$1,981,846	$3,696,591
132 Indiana Michigan Power Co - Generation	105,033,268	107,812,327	1,725,561	5,752,857	(6,273,762)	26,761	1,327,906	2,559,323
190 Indiana Michigan Power Co - Nuclear	203,788,804	236,367,773	6,264,198	11,349,534	(13,754,597)	67,613	2,576,443	6,503,191
120 Indiana Michigan Power Co - Transmission	35,491,372	35,509,586	502,223	1,937,278	(2,066,356)	8,588	448,707	830,440
280 Ind Mich River Transp Lakin	32,101,070	38,960,781	1,009,755	1,791,364	(2,267,187)	10,849	405,845	950,626
Indiana Michigan Power Co. - FERC	**$533,172,487**	**$577,113,245**	**$11,845,746**	**$29,385,837**	**($33,583,090)**	**$150,931**	**$6,740,747**	**$14,540,171**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$533,172,487**	**$577,113,245**	**$11,845,746**	**$29,385,837**	**($33,583,090)**	**$150,931**	**$6,740,747**	**$14,540,171**
110 Kentucky Power Co - Distribution	$68,497,499	$69,019,177	$984,762	$3,746,127	($4,016,330)	$21,315	$865,994	$1,601,868
117 Kentucky Power Co - Generation	33,226,597	33,365,400	362,921	1,810,966	(1,941,583)	10,918	420,074	663,296
180 Kentucky Power Co - Transmission	6,412,763	6,647,229	140,927	354,463	(386,812)	3,227	81,075	192,880
600 Kentucky Power Co. - Kammer Actives	4,960,482	6,075,197	187,475	279,014	(353,525)	1,383	62,714	177,061
701 Kentucky Power Co. - Mitchell Actives	28,096,457	40,743,865	1,035,211	1,584,857	(2,370,947)	6,082	355,215	610,418
702 Kentucky Power Co. - Mitchell Inactives	22,257,765	26,899,504	0	1,194,942	(1,565,323)	5,067	281,399	(83,915)
Kentucky Power Co.	**$163,451,563**	**$182,750,372**	**$2,711,296**	**$8,970,369**	**($10,634,520)**	**$47,992**	**$2,066,471**	**$3,161,608**
250 Ohio Power Co - Distribution	$409,074,349	$424,461,007	$6,017,354	$22,300,147	($24,700,026)	$96,985	$5,171,810	$8,886,270
160 Ohio Power Co - Transmission	45,394,881	44,350,617	29,227	2,433,207	(2,580,829)	19,325	573,914	474,844
Ohio Power Co.	**$454,469,230**	**$468,811,624**	**$6,046,581**	**$24,733,354**	**($27,280,855)**	**$116,310**	**$5,745,724**	**$9,361,114**
167 Public Service Co of Oklahoma - Distribution	$150,930,842	$157,220,618	$3,538,948	$8,254,824	($9,148,905)	$23,036	$1,908,175	$4,576,078
198 Public Service Co of Oklahoma - Generation	75,216,925	80,836,735	2,143,277	4,136,311	(4,704,012)	11,866	950,946	2,538,388
114 Public Service Co of Oklahoma - Transmission	18,017,632	19,527,618	449,088	989,108	(1,136,342)	2,611	227,792	532,257
Public Service Co. of Oklahoma	**$244,165,399**	**$257,584,971**	**$6,131,313**	**$13,380,243**	**($14,989,259)**	**$37,513**	**$3,086,913**	**$7,646,723**
159 Southwestern Electric Power Co - Distribution	$91,587,252	$100,463,072	$2,749,677	$5,052,533	($5,846,098)	$16,285	$1,157,911	$3,130,308
168 Southwestern Electric Power Co - Generation	101,079,215	108,539,938	3,336,407	5,574,079	(6,316,103)	15,968	1,277,916	3,888,267
161 Southwestern Electric Power Co - Texas - Distribution	49,177,128	50,193,366	1,281,003	2,691,013	(2,920,828)	8,496	621,732	1,681,416
111 Southwestern Electric Power Co - Texas - Transmission	139,843	129,370	0	7,347	(7,528)	0	1,768	1,587
194 Southwestern Electric Power Co - Transmission	14,052,314	15,794,186	398,385	776,560	(919,088)	2,932	177,659	436,448
Southwestern Electric Power Co.	**$256,035,752**	**$275,119,932**	**$7,765,472**	**$14,101,532**	**($16,009,645)**	**$43,681**	**$3,236,986**	**$9,138,026**
119 AEP Texas North Company - Distribution	63,800,998	64,669,401	1,432,592	3,486,999	(3,763,210)	10,480	806,618	1,973,479
166 AEP Texas North Company - Generation	19,964,326	23,460,482	0	1,068,186	(1,365,201)	92	252,403	(44,520)
192 AEP Texas North Company - Transmission	8,874,856	9,999,030	269,061	483,128	(581,859)	1,612	112,202	284,144
AEP Texas North Co.	**$92,640,180**	**$98,128,913**	**$1,701,653**	**$5,038,313**	**($5,710,270)**	**$12,184**	**$1,171,223**	**$2,213,103**
230 Kingsport Power Co - Distribution	$12,788,282	$13,027,540	$210,942	$700,152	($758,092)	$2,930	$161,679	$317,611
260 Kingsport Power Co - Transmission	2,601,457	2,558,190	22,118	141,150	(148,865)	389	32,889	47,681
Kingsport Power Co.	**$15,389,739**	**$15,585,730**	**$233,060**	**$841,302**	**($906,957)**	**$3,319**	**$194,568**	**$365,292**
210 Wheeling Power Co - Distribution	$14,777,593	$15,289,279	$224,648	$806,474	($889,706)	$4,849	$186,829	$333,094
200 Wheeling Power Co - Transmission	658,382	775,425	0	34,705	(45,123)	0	8,324	(2,094)
Wheeling Power Co.	**$15,435,975**	**$16,064,704**	**$224,648**	**$841,179**	**($934,829)**	**$4,849**	**$195,153**	**$331,000**
103 American Electric Power Service Corporation	$1,357,587,953	$1,395,141,132	$24,224,799	$74,440,911	($81,185,365)	$277,416	$17,163,596	$34,921,358
American Electric Power Service Corp	**$1,357,587,953**	**$1,395,141,132**	**$24,224,799**	**$74,440,911**	**($81,185,365)**	**$277,416**	**$17,163,596**	**$34,921,358**
143 AEP Pro Serv, Inc.	$1,010,512	$1,002,952	$0	$54,880	($58,363)	$39	$12,776	$9,332
171 CSW Energy, Inc.	9,926,249	12,181,170	597,741	568,448	(708,841)	1,319	125,495	584,162
293 Elmwood	2,857,516	5,773,174	287,347	168,295	(335,950)	3,927	36,127	159,746
292 AEP River Operations LLC	33,493,184	57,858,928	4,543,654	2,046,841	(3,366,898)	21,752	423,445	3,668,794
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$47,287,461**	**$76,816,224**	**$5,428,742**	**$2,838,464**	**($4,470,052)**	**$27,037**	**$597,843**	**$4,422,034**
270 Cook Coal Terminal	$3,520,213	$4,106,116	$93,274	$194,119	($238,941)	$855	$44,505	$93,812
AEP Generating Company	**$3,520,213**	**$4,106,116**	**$93,274**	**$194,119**	**($238,941)**	**$855**	**$44,505**	**$93,812**
104 Cardinal Operating Company	$73,624,099	$89,266,265	$1,295,578	$4,030,591	($5,194,539)	$15,877	$930,808	$1,078,315
181 Ohio Power Co - Generation	285,379,696	366,171,243	2,992,408	15,470,158	(21,308,057)	69,776	3,607,974	832,259
AEP Generation Resources - FERC	**$359,003,795**	**$455,437,508**	**$4,287,986**	**$19,500,749**	**($26,502,596)**	**$85,653**	**$4,538,782**	**$1,910,574**
290 Conesville Coal Preparation Company	3,082,343	4,212,510	0	165,636	(245,132)	614	38,969	(39,913)
AEP Generation Resources - SEC	**$362,086,138**	**$459,650,018**	**$4,287,986**	**$19,666,385**	**($26,747,728)**	**$86,267**	**$4,577,751**	**$1,870,661**
Total	**$4,445,716,907**	**$4,747,456,095**	**$84,281,077**	**$243,521,372**	**($276,261,632)**	**$1,008,873**	**$56,205,925**	**$108,755,616**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2018 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$302,177,024	$308,338,825	$4,314,924	$16,740,307	($17,945,116)	$865	$2,949,369	$6,060,349
215 Appalachian Power Co - Generation	254,853,974	263,784,396	4,133,533	14,177,745	(15,352,077)	815	2,487,477	5,447,493
150 Appalachian Power Co - Transmission	35,203,880	35,494,959	244,054	1,942,032	(2,065,783)	126	343,604	464,033
Appalachian Power Co. - FERC	**$592,234,878**	**$607,618,180**	**$8,692,511**	**$32,860,084**	**($35,362,976)**	**$1,806**	**$5,780,450**	**$11,971,875**
225 Cedar Coal Co	3,183,224	4,517,519	0	173,387	(262,917)	0	31,070	(58,460)
Appalachian Power Co. - SEC	**$595,418,102**	**$612,135,699**	**$8,692,511**	**$33,033,471**	**($35,625,893)**	**$1,806**	**$5,811,520**	**$11,913,415**
211 AEP Texas Central Company - Distribution	$256,718,540	$264,152,171	$4,955,272	$14,253,542	($15,373,482)	$66	$2,505,676	$6,341,074
147 AEP Texas Central Company - Generation	6,727,261	15,279,123	0	357,834	(889,235)	0	65,661	(465,740)
169 AEP Texas Central Company - Transmission	24,907,321	25,458,024	619,742	1,394,936	(1,481,640)	10	243,105	776,153
AEP Texas Central Co.	**$288,353,122**	**$304,889,318**	**$5,575,014**	**$16,006,312**	**($17,744,357)**	**$76**	**$2,814,442**	**$6,651,487**
170 Indiana Michigan Power Co - Distribution	$153,850,150	$158,070,278	$2,461,502	$8,521,012	($9,199,586)	$408	$1,501,639	$3,284,975
132 Indiana Michigan Power Co - Generation	103,084,926	108,287,827	1,812,054	5,744,906	(6,302,280)	294	1,006,150	2,261,124
190 Indiana Michigan Power Co - Nuclear	200,008,570	243,116,559	6,578,188	11,370,681	(14,149,223)	744	1,952,164	5,752,554
120 Indiana Michigan Power Co - Transmission	34,833,015	35,578,710	527,397	1,935,523	(2,070,657)	94	339,984	732,341
280 Ind Mich River Transp Lakin	31,505,603	40,252,347	1,060,369	1,788,862	(2,342,660)	119	307,507	814,197
Indiana Michigan Power Co. - FERC	**$523,282,264**	**$585,305,721**	**$12,439,510**	**$29,360,984**	**($34,064,406)**	**$1,659**	**$5,107,444**	**$12,845,191**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$523,282,264**	**$585,305,721**	**$12,439,510**	**$29,360,984**	**($34,064,406)**	**$1,659**	**$5,107,444**	**$12,845,191**
110 Kentucky Power Co - Distribution	$67,226,886	$69,181,469	$1,034,123	$3,733,971	($4,026,316)	$235	$656,161	$1,398,174
117 Kentucky Power Co - Generation	32,610,252	33,325,255	381,112	1,806,972	(1,939,508)	120	318,289	566,985
180 Kentucky Power Co - Transmission	6,293,808	6,764,605	147,991	353,851	(393,696)	36	61,430	169,612
600 Kentucky Power Co. - Kammer Actives	4,868,467	6,327,661	196,872	277,443	(368,266)	15	47,518	153,582
701 Kentucky Power Co. - Mitchell Actives	27,575,275	42,807,641	1,087,100	1,573,040	(2,491,376)	67	269,146	437,977
702 Kentucky Power Co. - Mitchell Inactives	21,844,888	26,751,782	0	1,194,179	(1,556,936)	56	213,215	(149,486)
Kentucky Power Co.	**$160,419,576**	**$185,158,413**	**$2,847,198**	**$8,939,456**	**($10,776,098)**	**$529**	**$1,565,759**	**$2,576,844**
250 Ohio Power Co - Distribution	$401,486,118	$423,353,235	$6,318,971	$22,280,880	($24,638,878)	$1,066	$3,918,666	$7,880,705
160 Ohio Power Co - Transmission	44,552,817	43,791,453	30,692	2,431,997	(2,548,634)	213	434,853	349,121
Ohio Power Co.	**$446,038,935**	**$467,144,688**	**$6,349,663**	**$24,712,877**	**($27,187,512)**	**$1,279**	**$4,353,519**	**$8,229,826**
167 Public Service Co of Oklahoma - Distribution	$148,131,111	$156,440,298	$3,716,337	$8,252,506	($9,104,722)	$77	$1,445,819	$4,310,017
198 Public Service Co of Oklahoma - Generation	73,821,669	81,060,168	2,250,708	4,131,158	(4,717,648)	31	720,529	2,384,778
114 Public Service Co of Oklahoma - Transmission	17,683,409	19,597,036	471,599	989,733	(1,140,535)	5	172,597	493,399
Public Service Co. of Oklahoma	**$239,636,189**	**$257,097,502**	**$6,438,644**	**$13,373,397**	**($14,962,905)**	**$113**	**$2,338,945**	**$7,188,194**
159 Southwestern Electric Power Co - Distribution	$89,888,331	$101,331,512	$2,887,504	$5,031,400	($5,897,427)	$45	$877,346	$2,898,868
168 Southwestern Electric Power Co - Generation	99,204,220	108,929,460	3,503,643	5,585,767	(6,339,622)	32	968,273	3,718,093
161 Southwestern Electric Power Co - Texas - Distribution	48,264,904	49,781,196	1,345,212	2,703,553	(2,897,233)	22	471,085	1,622,639
111 Southwestern Electric Power Co - Texas - Transmission	137,249	129,117	0	7,379	(7,515)	0	1,340	1,204
194 Southwestern Electric Power Co - Transmission	13,791,647	16,030,390	418,354	775,788	(932,958)	9	134,612	395,805
Southwestern Electric Power Co.	**$251,286,351**	**$276,201,675**	**$8,154,713**	**$14,103,887**	**($16,074,755)**	**$108**	**$2,452,656**	**$8,636,609**
119 AEP Texas North Company - Distribution	62,617,505	64,193,596	1,504,400	3,486,002	(3,736,025)	17	611,172	1,865,566
166 AEP Texas North Company - Generation	19,593,993	23,143,809	0	1,067,369	(1,346,954)	0	191,245	(88,340)
192 AEP Texas North Company - Transmission	8,710,229	9,850,559	282,547	488,305	(573,296)	4	85,015	282,575
AEP Texas North Co.	**$90,921,727**	**$97,187,964**	**$1,786,947**	**$5,041,676**	**($5,656,275)**	**$21**	**$887,432**	**$2,059,801**
230 Kingsport Power Co - Distribution	$12,551,062	$13,067,221	$221,515	$699,423	($760,504)	$32	$122,503	$282,969
260 Kingsport Power Co - Transmission	2,553,201	2,557,237	23,226	141,283	(148,830)	4	24,920	40,603
Kingsport Power Co.	**$15,104,263**	**$15,624,458**	**$244,741**	**$840,706**	**($909,334)**	**$36**	**$147,423**	**$323,572**
210 Wheeling Power Co - Distribution	$14,503,473	$15,272,195	$235,909	$804,394	($888,832)	$53	$141,560	$293,084
200 Wheeling Power Co - Transmission	646,169	745,123	0	34,777	(43,366)	0	6,307	(2,282)
Wheeling Power Co.	**$15,149,642**	**$16,017,318**	**$235,909**	**$839,171**	**($932,198)**	**$53**	**$147,867**	**$290,802**
103 American Electric Power Service Corporation	$1,332,405,027	$1,402,484,353	$25,439,057	$74,322,959	($81,623,662)	$2,758	$13,004,812	$31,145,924
American Electric Power Service Corp	**$1,332,405,027**	**$1,402,484,353**	**$25,439,057**	**$74,322,959**	**($81,623,662)**	**$2,758**	**$13,004,812**	**$31,145,924**
143 AEP Pro Serv, Inc.	$991,767	$1,005,518	$0	$55,167	($58,520)	$0	$9,680	$6,327
171 CSW Energy, Inc.	9,742,119	12,831,826	627,703	579,038	(746,804)	13	95,087	555,037
293 Elmwood	2,804,510	6,165,495	301,750	169,915	(358,828)	43	27,373	140,253
292 AEP River Operations LLC	32,871,893	63,347,361	4,771,403	2,065,469	(3,686,774)	239	320,843	3,471,180
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$46,410,289**	**$83,350,200**	**$5,700,856**	**$2,869,589**	**($4,850,926)**	**$295**	**$452,983**	**$4,172,797**
270 Cook Coal Terminal	$3,454,914	$4,166,439	$97,949	$194,127	($242,484)	$9	$33,721	$83,322
AEP Generating Company	**$3,454,914**	**$4,166,439**	**$97,949**	**$194,127**	**($242,484)**	**$9**	**$33,721**	**$83,322**
104 Cardinal Operating Company	$72,258,390	$90,359,851	$1,360,519	$4,029,139	($5,258,884)	$175	$705,271	$836,220
181 Ohio Power Co - Generation	280,085,971	368,143,162	3,142,401	15,468,016	(21,425,688)	768	2,733,752	(80,751)
AEP Generation Resources - FERC	**$352,344,361**	**$458,503,013**	**$4,502,920**	**$19,497,155**	**($26,684,572)**	**$943**	**$3,439,023**	**$755,469**
290 Conesville Coal Preparation Company	3,025,166	4,231,045	0	165,438	(246,244)	7	29,527	(51,272)
AEP Generation Resources - SEC	**$355,369,527**	**$462,734,058**	**$4,502,920**	**$19,662,593**	**($26,930,816)**	**$950**	**$3,468,550**	**$704,197**
Total	**$4,363,249,928**	**$4,769,497,806**	**$88,505,632**	**$243,301,205**	**($277,581,621)**	**$9,692**	**$42,587,073**	**$96,821,981**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2019 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$296,520,531	$305,707,448	$4,533,988	$16,741,243	($17,803,062)	$0	$2,181,351	$5,653,520
215 Appalachian Power Co - Generation	250,083,328	263,501,011	4,343,387	14,158,316	(15,345,144)	0	1,839,736	4,996,295
150 Appalachian Power Co - Transmission	34,544,894	35,133,075	256,445	1,930,908	(2,045,996)	0	254,129	395,486
Appalachian Power Co. - FERC	**$581,148,753**	**$604,341,534**	**$9,133,820**	**$32,830,467**	**($35,194,202)**	**$0**	**$4,275,216**	**$11,045,301**
225 Cedar Coal Co	3,123,637	4,511,813	0	173,155	(262,748)	0	22,979	(66,614)
Appalachian Power Co. - SEC	**$584,272,390**	**$608,853,347**	**$9,133,820**	**$33,003,622**	**($35,456,950)**	**$0**	**$4,298,195**	**$10,978,687**
211 AEP Texas Central Company - Distribution	$251,912,991	$261,838,617	$5,206,845	$14,246,436	($15,248,333)	$0	$1,853,196	$6,058,144
147 AEP Texas Central Company - Generation	6,601,333	15,321,424	0	366,495	(892,253)	0	48,563	(477,195)
169 AEP Texas Central Company - Transmission	24,441,077	25,524,483	651,206	1,392,554	(1,486,434)	0	179,801	737,127
AEP Texas Central Co.	**$282,955,401**	**$302,684,524**	**$5,858,051**	**$16,005,485**	**($17,627,020)**	**$0**	**$2,081,560**	**$6,318,076**
170 Indiana Michigan Power Co - Distribution	$150,970,208	$156,430,835	$2,586,469	$8,540,399	($9,109,846)	$0	$1,110,611	$3,127,633
132 Indiana Michigan Power Co - Generation	101,155,266	108,509,886	1,904,050	5,724,959	(6,319,140)	0	744,148	2,054,017
190 Indiana Michigan Power Co - Nuclear	196,264,583	250,835,578	6,912,154	11,332,072	(14,607,565)	0	1,443,819	5,080,480
120 Indiana Michigan Power Co - Transmission	34,180,971	35,464,341	554,172	1,933,709	(2,065,288)	0	251,452	674,045
280 Ind Mich River Transp Lakin	30,915,845	41,485,337	1,114,203	1,783,328	(2,415,924)	0	227,432	709,039
Indiana Michigan Power Co. - FERC	**$513,486,873**	**$592,725,977**	**$13,071,048**	**$29,314,467**	**($34,517,763)**	**$0**	**$3,777,462**	**$11,645,214**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$513,486,873**	**$592,725,977**	**$13,071,048**	**$29,314,467**	**($34,517,763)**	**$0**	**$3,777,462**	**$11,645,214**
110 Kentucky Power Co - Distribution	$65,968,457	$68,918,189	$1,086,624	$3,729,662	($4,013,493)	$0	$485,296	$1,288,089
117 Kentucky Power Co - Generation	31,999,816	33,152,927	400,461	1,803,539	(1,930,681)	0	235,406	508,725
180 Kentucky Power Co - Transmission	6,175,993	6,864,287	155,504	353,554	(399,746)	0	45,434	154,746
600 Kentucky Power Co. - Kammer Actives	4,777,333	6,527,915	206,867	275,964	(380,157)	0	35,144	137,818
701 Kentucky Power Co. - Mitchell Actives	27,059,090	44,490,653	1,142,291	1,570,648	(2,590,941)	0	199,060	321,058
702 Kentucky Power Co. - Mitchell Inactives	21,435,971	26,594,575	0	1,192,869	(1,548,751)	0	157,694	(198,188)
Kentucky Power Co.	**$157,416,660**	**$186,548,546**	**$2,991,747**	**$8,926,236**	**($10,863,769)**	**$0**	**$1,158,034**	**$2,212,248**
250 Ohio Power Co - Distribution	$393,970,645	$421,589,345	$6,639,777	$22,260,280	($24,551,516)	$0	$2,898,242	$7,246,783
160 Ohio Power Co - Transmission	43,718,827	43,204,555	32,250	2,422,367	(2,516,044)	0	321,617	260,190
Ohio Power Co.	**$437,689,472**	**$464,793,900**	**$6,672,027**	**$24,682,647**	**($27,067,560)**	**$0**	**$3,219,859**	**$7,506,973**
167 Public Service Co of Oklahoma - Distribution	$145,358,224	$155,485,335	$3,905,010	$8,261,246	($9,054,784)	$0	$1,069,327	$4,180,799
198 Public Service Co of Oklahoma - Generation	72,439,791	81,050,227	2,364,974	4,128,046	(4,720,010)	0	532,903	2,305,913
114 Public Service Co of Oklahoma - Transmission	17,352,391	19,685,703	495,541	981,214	(1,146,409)	0	127,653	457,999
Public Service Co. of Oklahoma	**$235,150,406**	**$256,221,265**	**$6,765,525**	**$13,370,506**	**($14,921,203)**	**$0**	**$1,729,883**	**$6,944,711**
159 Southwestern Electric Power Co - Distribution	$88,205,699	$101,373,818	$3,034,099	$5,047,749	($5,903,567)	$0	$648,884	$2,827,165
168 Southwestern Electric Power Co - Generation	97,347,203	109,679,597	3,681,518	5,580,468	(6,387,259)	0	716,134	3,590,861
161 Southwestern Electric Power Co - Texas - Distribution	47,361,427	49,798,027	1,413,507	2,704,706	(2,900,019)	0	348,414	1,566,608
111 Southwestern Electric Power Co - Texas - Transmission	134,680	129,360	0	7,406	(7,533)	0	991	864
194 Southwestern Electric Power Co - Transmission	13,533,479	16,240,550	439,594	777,379	(945,778)	0	99,559	370,754
Southwestern Electric Power Co.	**$246,582,488**	**$277,221,352**	**$8,568,718**	**$14,117,708**	**($16,144,156)**	**$0**	**$1,813,982**	**$8,356,252**
119 AEP Texas North Company - Distribution	61,445,359	63,641,547	1,580,777	3,472,967	(3,706,205)	0	452,022	1,799,561
166 AEP Texas North Company - Generation	19,227,210	22,804,414	0	1,066,093	(1,328,029)	0	141,445	(120,491)
192 AEP Texas North Company - Transmission	8,547,181	9,882,782	296,892	487,781	(575,530)	0	62,877	272,020
AEP Texas North Co.	**$89,219,750**	**$96,328,743**	**$1,877,669**	**$5,026,841**	**($5,609,764)**	**$0**	**$656,344**	**$1,951,090**
230 Kingsport Power Co - Distribution	$12,316,117	$13,083,776	$232,761	$698,840	($761,942)	$0	$90,603	$260,262
260 Kingsport Power Co - Transmission	2,505,407	2,549,748	24,405	140,995	(148,486)	0	18,431	35,345
Kingsport Power Co.	**$14,821,524**	**$15,633,524**	**$257,166**	**$839,835**	**($910,428)**	**$0**	**$109,034**	**$295,607**
210 Wheeling Power Co - Distribution	$14,231,980	$15,179,775	$247,886	$802,699	($884,004)	$0	$104,697	$271,278
200 Wheeling Power Co - Transmission	634,073	716,752	0	34,842	(41,740)	0	4,665	(2,233)
Wheeling Power Co.	**$14,866,053**	**$15,896,527**	**$247,886**	**$837,541**	**($925,744)**	**$0**	**$109,362**	**$269,045**
103 American Electric Power Service Corporation	$1,307,463,556	$1,405,901,457	$26,730,565	$74,276,780	($81,873,542)	($3)	$9,618,344	$28,752,143
American Electric Power Service Corp	**$1,307,463,556**	**$1,405,901,457**	**$26,730,565**	**$74,276,780**	**($81,873,542)**	**($3)**	**$9,618,344**	**$28,752,143**
143 AEP Pro Serv, Inc.	$973,202	$1,020,481	$0	$55,067	($59,428)	$0	$7,159	$2,798
171 CSW Energy, Inc.	9,559,755	13,886,641	659,571	579,498	(808,697)	0	70,326	500,698
293 Elmwood	2,752,012	6,621,795	317,069	169,091	(385,624)	0	20,245	120,781
292 AEP River Operations LLC	32,256,560	69,536,794	5,013,641	2,077,488	(4,049,518)	0	237,295	3,278,906
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$45,541,529**	**$91,065,711**	**$5,990,281**	**$2,881,144**	**($5,303,267)**	**$0**	**$335,025**	**$3,903,183**
270 Cook Coal Terminal	$3,390,241	$4,228,071	$102,922	$193,152	($246,224)	$0	$24,940	$74,790
AEP Generating Company	**$3,390,241**	**$4,228,071**	**$102,922**	**$193,152**	**($246,224)**	**$0**	**$24,940**	**$74,790**
104 Cardinal Operating Company	$70,905,775	$91,454,067	$1,429,590	$4,026,654	($5,325,884)	$0	$521,618	$651,978
181 Ohio Power Co - Generation	274,843,004	370,258,238	3,301,937	15,452,323	(21,562,217)	0	2,021,880	(786,077)
AEP Generation Resources - FERC	**$345,748,779**	**$461,712,305**	**$4,731,527**	**$19,478,977**	**($26,888,101)**	**$0**	**$2,543,498**	**($134,099)**
290 Conesville Coal Preparation Company	2,968,538	4,246,476	0	165,166	(247,296)	0	21,838	(60,292)
AEP Generation Resources - SEC	**$348,717,317**	**$465,958,781**	**$4,731,527**	**$19,644,143**	**($27,135,397)**	**$0**	**$2,565,336**	**($194,391)**
Total	**$4,281,573,660**	**$4,784,061,725**	**$92,998,952**	**$243,120,107**	**($278,602,787)**	**($3)**	**$31,497,360**	**$89,013,628**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2020 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$294,044,689	$302,597,625	$4,722,471	$16,615,474	($17,633,972)	$0	$1,953,613	$5,657,586
215 Appalachian Power Co - Generation	247,995,220	262,100,038	4,523,947	14,049,410	(15,273,962)	0	1,647,663	4,947,058
150 Appalachian Power Co - Transmission	34,256,456	34,316,809	267,105	1,922,458	(1,999,823)	0	227,598	417,338
Appalachian Power Co. - FERC	**$576,296,365**	**$599,014,472**	**$9,513,523**	**$32,587,342**	**($34,907,757)**	**$0**	**$3,828,874**	**$11,021,982**
225 Cedar Coal Co	3,097,556	4,492,141	0	171,840	(261,781)	0	20,580	(69,361)
Appalachian Power Co. - SEC	**$579,393,921**	**$603,506,613**	**$9,513,523**	**$32,759,182**	**($35,169,538)**	**$0**	**$3,849,454**	**$10,952,621**
211 AEP Texas Central Company - Distribution	$249,809,606	$258,719,260	$5,423,300	$14,141,674	($15,076,946)	$0	$1,659,718	$6,147,746
147 AEP Texas Central Company - Generation	6,546,214	15,657,065	0	356,091	(912,420)	0	43,493	(512,836)
169 AEP Texas Central Company - Transmission	24,237,003	25,453,227	678,277	1,383,914	(1,483,295)	0	161,029	739,925
AEP Texas Central Co.	**$280,592,823**	**$299,829,552**	**$6,101,577**	**$15,881,679**	**($17,472,661)**	**$0**	**$1,864,240**	**$6,374,835**
170 Indiana Michigan Power Co - Distribution	$149,709,660	$155,213,244	$2,693,992	$8,479,414	($9,045,101)	$0	$994,661	$3,122,966
132 Indiana Michigan Power Co - Generation	100,310,655	107,829,942	1,983,203	5,687,549	(6,283,824)	0	666,457	2,053,385
190 Indiana Michigan Power Co - Nuclear	194,625,843	256,797,227	7,199,501	11,233,658	(14,964,939)	0	1,293,081	4,761,301
120 Indiana Michigan Power Co - Transmission	33,895,572	35,229,276	577,210	1,919,062	(2,052,997)	0	225,200	668,475
280 Ind Mich River Transp Lakin	30,657,709	42,454,409	1,160,521	1,765,038	(2,474,044)	0	203,688	655,203
Indiana Michigan Power Co. - FERC	**$509,199,439**	**$597,524,098**	**$13,614,427**	**$29,084,721**	**($34,820,905)**	**$0**	**$3,383,087**	**$11,261,330**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$509,199,439**	**$597,524,098**	**$13,614,427**	**$29,084,721**	**($34,820,905)**	**$0**	**$3,383,087**	**$11,261,330**
110 Kentucky Power Co - Distribution	$65,417,644	$68,388,233	$1,131,797	$3,700,446	($3,985,346)	$0	$434,630	$1,281,527
117 Kentucky Power Co - Generation	31,732,629	32,808,027	417,108	1,789,708	(1,911,898)	0	210,829	505,747
180 Kentucky Power Co - Transmission	6,124,426	6,944,078	161,969	351,130	(404,668)	0	40,690	149,121
600 Kentucky Power Co. - Kammer Actives	4,737,444	6,661,644	215,467	273,922	(388,209)	0	31,475	132,655
701 Kentucky Power Co. - Mitchell Actives	26,833,156	46,022,985	1,189,777	1,559,737	(2,682,004)	0	178,278	245,788
702 Kentucky Power Co. - Mitchell Inactives	21,256,988	26,361,008	0	1,184,277	(1,536,196)	0	141,230	(210,689)
Kentucky Power Co.	**$156,102,287**	**$187,185,975**	**$3,116,118**	**$8,859,220**	**($10,908,321)**	**$0**	**$1,037,132**	**$2,104,149**
250 Ohio Power Co - Distribution	$390,681,128	$418,366,022	$6,915,801	$22,090,901	($24,380,412)	$0	$2,595,659	$7,221,949
160 Ohio Power Co - Transmission	43,353,790	42,168,724	33,591	2,411,041	(2,457,396)	0	288,040	275,276
Ohio Power Co.	**$434,034,918**	**$460,534,746**	**$6,949,392**	**$24,501,942**	**($26,837,808)**	**$0**	**$2,883,699**	**$7,497,225**
167 Public Service Co of Oklahoma - Distribution	$144,144,534	$154,482,377	$4,067,347	$8,226,433	($9,002,509)	$0	$957,686	$4,248,957
198 Public Service Co of Oklahoma - Generation	71,834,944	80,719,739	2,463,288	4,094,239	(4,703,968)	0	477,266	2,330,825
114 Public Service Co of Oklahoma - Transmission	17,207,505	19,418,113	516,141	981,937	(1,131,597)	0	114,325	480,806
Public Service Co. of Oklahoma	**$233,186,983**	**$254,620,229**	**$7,046,776**	**$13,302,609**	**($14,838,074)**	**$0**	**$1,549,277**	**$7,060,588**
159 Southwestern Electric Power Co - Distribution	$87,469,212	$101,756,496	$3,160,230	$5,012,458	($5,929,892)	$0	$581,139	$2,823,935
168 Southwestern Electric Power Co - Generation	96,534,388	109,956,654	3,834,564	5,549,999	(6,407,759)	0	641,368	3,618,172
161 Southwestern Electric Power Co - Texas - Distribution	46,965,976	49,745,572	1,472,268	2,683,858	(2,898,939)	0	312,039	1,569,226
111 Southwestern Electric Power Co - Texas - Transmission	133,555	127,602	0	7,386	(7,436)	0	887	837
194 Southwestern Electric Power Co - Transmission	13,420,479	16,477,516	457,868	773,905	(960,232)	0	89,165	360,706
Southwestern Electric Power Co.	**$244,523,610**	**$278,063,840**	**$8,924,930**	**$14,027,606**	**($16,204,258)**	**$0**	**$1,624,598**	**$8,372,876**
119 AEP Texas North Company - Distribution	60,932,312	62,453,164	1,646,492	3,465,080	(3,639,478)	0	404,830	1,876,924
166 AEP Texas North Company - Generation	19,066,670	22,386,833	0	1,058,246	(1,304,600)	0	126,678	(119,676)
192 AEP Texas North Company - Transmission	8,475,816	9,870,058	309,234	485,199	(575,181)	0	56,313	275,565
AEP Texas North Co.	**$88,474,798**	**$94,710,055**	**$1,955,726**	**$5,008,525**	**($5,519,259)**	**$0**	**$587,821**	**$2,032,813**
230 Kingsport Power Co - Distribution	$12,213,282	$13,058,499	$242,438	$694,017	($760,988)	$0	$81,144	$256,611
260 Kingsport Power Co - Transmission	2,484,488	2,519,403	25,420	139,928	(146,819)	0	16,507	35,036
Kingsport Power Co.	**$14,697,770**	**$15,577,902**	**$267,858**	**$833,945**	**($907,807)**	**$0**	**$97,651**	**$291,647**
210 Wheeling Power Co - Distribution	$14,113,148	$14,998,438	$258,191	$798,627	($874,039)	$0	$93,767	$276,546
200 Wheeling Power Co - Transmission	628,779	689,075	0	34,695	(40,156)	0	4,178	(1,283)
Wheeling Power Co.	**$14,741,927**	**$15,687,513**	**$258,191**	**$833,322**	**($914,195)**	**$0**	**$97,945**	**$275,263**
103 American Electric Power Service Corporation	$1,296,546,691	$1,405,391,286	$27,841,788	$73,690,563	($81,899,617)	($1)	$8,614,169	$28,246,902
American Electric Power Service Corp	**$1,296,546,691**	**$1,405,391,286**	**$27,841,788**	**$73,690,563**	**($81,899,617)**	**($1)**	**$8,614,169**	**$28,246,902**
143 AEP Pro Serv, Inc.	$965,076	$1,032,142	$0	$54,604	($60,148)	$0	$6,412	$868
171 CSW Energy, Inc.	9,479,934	14,947,642	686,990	573,998	(871,079)	0	62,984	452,893
293 Elmwood	2,729,034	7,033,117	330,250	168,562	(409,857)	0	18,132	107,087
292 AEP River Operations LLC	31,987,229	75,988,306	5,222,064	2,071,061	(4,428,242)	0	212,521	3,077,404
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$45,161,273**	**$99,001,207**	**$6,239,304**	**$2,868,225**	**($5,769,326)**	**$0**	**$300,049**	**$3,638,252**
270 Cook Coal Terminal	$3,361,934	$4,245,919	$107,201	$192,073	($247,432)	$0	$22,336	$74,178
AEP Generating Company	**$3,361,934**	**$4,245,919**	**$107,201**	**$192,073**	**($247,432)**	**$0**	**$22,336**	**$74,178**
104 Cardinal Operating Company	$70,313,737	$92,330,571	$1,489,020	$3,993,996	($5,380,593)	$0	$467,160	$569,583
181 Ohio Power Co - Generation	272,548,161	371,302,954	3,439,202	15,351,872	(21,637,797)	0	1,810,791	(1,035,932)
AEP Generation Resources - FERC	**$342,861,898**	**$463,633,525**	**$4,928,222**	**$19,345,868**	**($27,018,390)**	**$0**	**$2,277,951**	**($466,349)**
290 Conesville Coal Preparation Company	2,943,751	4,247,860	0	164,057	(247,545)	0	19,558	(63,930)
AEP Generation Resources - SEC	**$345,805,649**	**$467,881,385**	**$4,928,222**	**$19,509,925**	**($27,265,935)**	**$0**	**$2,297,509**	**($530,279)**
Total	**$4,245,824,023**	**$4,783,760,320**	**$96,865,033**	**$241,353,537**	**($278,775,136)**	**($1)**	**$28,208,967**	**$87,652,400**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2021 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$291,915,023	$299,686,103	$4,845,737	$16,493,850	($17,466,966)	$0	$1,744,672	$5,617,293
215 Appalachian Power Co - Generation	246,199,075	260,807,286	4,642,031	13,949,854	(15,200,945)	0	1,471,444	4,862,384
150 Appalachian Power Co - Transmission	34,008,348	33,961,379	274,077	1,898,459	(1,979,412)	0	203,256	396,380
Appalachian Power Co. - FERC	**$572,122,446**	**$594,454,768**	**$9,761,845**	**$32,342,163**	**($34,647,323)**	**$0**	**$3,419,372**	**$10,876,057**
225 Cedar Coal Co	3,075,121	4,478,397	0	170,744	(261,020)	0	18,379	(71,897)
Appalachian Power Co. - SEC	**$575,197,567**	**$598,933,165**	**$9,761,845**	**$32,512,907**	**($34,908,343)**	**$0**	**$3,437,751**	**$10,804,160**
211 AEP Texas Central Company - Distribution	$248,000,320	$255,739,573	$5,564,859	$14,044,002	($14,905,577)	$0	$1,482,209	$6,185,493
147 AEP Texas Central Company - Generation	6,498,802	15,745,089	0	353,100	(917,690)	0	38,841	(525,749)
169 AEP Texas Central Company - Transmission	24,061,462	25,458,014	695,981	1,376,038	(1,483,800)	0	143,807	732,026
AEP Texas Central Co.	**$278,560,584**	**$296,942,676**	**$6,260,840**	**$15,773,140**	**($17,307,067)**	**$0**	**$1,664,857**	**$6,391,770**
170 Indiana Michigan Power Co - Distribution	$148,625,363	$154,217,185	$2,764,311	$8,424,524	($8,988,426)	$0	$888,281	$3,088,690
132 Indiana Michigan Power Co - Generation	99,584,139	107,425,219	2,034,969	5,645,053	(6,261,193)	0	595,179	2,014,008
190 Indiana Michigan Power Co - Nuclear	193,216,234	262,595,295	7,387,423	11,150,776	(15,305,158)	0	1,154,784	4,387,825
120 Indiana Michigan Power Co - Transmission	33,650,078	35,017,333	592,276	1,905,807	(2,040,957)	0	201,114	658,240
280 Ind Mich River Transp Lakin	30,435,666	43,294,347	1,190,813	1,759,759	(2,523,377)	0	181,903	609,098
Indiana Michigan Power Co. - FERC	**$505,511,480**	**$602,549,379**	**$13,969,792**	**$28,885,919**	**($35,119,111)**	**$0**	**$3,021,261**	**$10,757,861**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$505,511,480**	**$602,549,379**	**$13,969,792**	**$28,885,919**	**($35,119,111)**	**$0**	**$3,021,261**	**$10,757,861**
110 Kentucky Power Co - Distribution	$64,943,846	$67,861,684	$1,161,339	$3,672,131	($3,955,264)	$0	$388,146	$1,266,352
117 Kentucky Power Co - Generation	31,502,800	32,480,221	427,996	1,772,327	(1,893,084)	0	188,281	495,520
180 Kentucky Power Co - Transmission	6,080,069	7,039,813	166,197	348,509	(410,310)	0	36,338	140,734
600 Kentucky Power Co. - Kammer Actives	4,703,132	6,801,227	221,091	271,564	(396,404)	0	28,109	124,360
701 Kentucky Power Co. - Mitchell Actives	26,638,812	47,663,871	1,220,833	1,542,700	(2,778,051)	0	159,211	144,693
702 Kentucky Power Co. - Mitchell Inactives	21,103,031	26,178,277	0	1,176,867	(1,525,780)	0	126,125	(222,788)
Kentucky Power Co.	**$154,971,690**	**$188,025,093**	**$3,197,456**	**$8,784,098**	**($10,958,893)**	**$0**	**$926,210**	**$1,948,871**
250 Ohio Power Co - Distribution	$387,851,557	$415,342,231	$7,096,317	$21,967,647	($24,207,891)	$0	$2,318,050	$7,174,123
160 Ohio Power Co - Transmission	43,039,793	42,143,244	34,467	2,396,973	(2,456,285)	0	257,233	232,388
Ohio Power Co.	**$430,891,350**	**$457,485,475**	**$7,130,784**	**$24,364,620**	**($26,664,176)**	**$0**	**$2,575,283**	**$7,406,511**
167 Public Service Co of Oklahoma - Distribution	$143,100,544	$154,509,476	$4,173,512	$8,151,491	($9,005,462)	$0	$855,261	$4,174,802
198 Public Service Co of Oklahoma - Generation	71,314,668	80,278,297	2,527,585	4,082,000	(4,678,957)	0	426,222	2,356,850
114 Public Service Co of Oklahoma - Transmission	17,082,877	19,443,552	529,614	975,850	(1,133,252)	0	102,098	474,310
Public Service Co. of Oklahoma	**$231,498,089**	**$254,231,325**	**$7,230,711**	**$13,209,341**	**($14,817,671)**	**$0**	**$1,383,581**	**$7,005,962**
159 Southwestern Electric Power Co - Distribution	$86,835,703	$102,261,899	$3,242,718	$4,975,473	($5,960,253)	$0	$518,986	$2,776,924
168 Southwestern Electric Power Co - Generation	95,835,222	110,655,193	3,934,654	5,508,010	(6,449,450)	0	572,773	3,565,987
161 Southwestern Electric Power Co - Texas - Distribution	46,625,817	49,684,224	1,510,697	2,673,665	(2,895,805)	0	278,666	1,567,223
111 Southwestern Electric Power Co - Texas - Transmission	132,588	128,455	0	7,372	(7,487)	0	792	677
194 Southwestern Electric Power Co - Transmission	13,323,279	16,818,212	469,819	768,477	(980,236)	0	79,628	337,688
Southwestern Electric Power Co.	**$242,752,609**	**$279,547,983**	**$9,157,888**	**$13,932,997**	**($16,293,231)**	**$0**	**$1,450,845**	**$8,248,499**
119 AEP Texas North Company - Distribution	60,491,000	62,043,924	1,689,468	3,444,282	(3,616,181)	0	361,533	1,879,102
166 AEP Texas North Company - Generation	18,928,576	21,996,865	0	1,052,105	(1,282,070)	0	113,129	(116,836)
192 AEP Texas North Company - Transmission	8,414,428	9,896,882	317,306	482,486	(576,832)	0	50,290	273,250
AEP Texas North Co.	**$87,834,004**	**$93,937,671**	**$2,006,774**	**$4,978,873**	**($5,475,083)**	**$0**	**$524,952**	**$2,035,516**
230 Kingsport Power Co - Distribution	$12,124,825	$13,061,094	$248,766	$688,649	($761,255)	$0	$72,466	$248,626
260 Kingsport Power Co - Transmission	2,466,494	2,491,382	26,084	138,830	(145,208)	0	14,741	34,447
Kingsport Power Co.	**$14,591,319**	**$15,552,476**	**$274,850**	**$827,479**	**($906,463)**	**$0**	**$87,207**	**$283,073**
210 Wheeling Power Co - Distribution	$14,010,931	$14,895,173	$264,930	$792,977	($868,153)	$0	$83,738	$273,492
200 Wheeling Power Co - Transmission	624,225	665,610	0	34,593	(38,795)	0	3,731	(471)
Wheeling Power Co.	**$14,635,156**	**$15,560,783**	**$264,930**	**$827,570**	**($906,948)**	**$0**	**$87,469**	**$273,021**
103 American Electric Power Service Corporation	$1,287,156,243	$1,405,012,100	$28,568,514	$73,188,470	($81,890,013)	$3	$7,692,876	$27,559,850
American Electric Power Service Corp	**$1,287,156,243**	**$1,405,012,100**	**$28,568,514**	**$73,188,470**	**($81,890,013)**	**$3**	**$7,692,876**	**$27,559,850**
143 AEP Pro Serv, Inc.	$958,087	$1,044,808	$0	$54,209	($60,896)	$0	$5,726	($961)
171 CSW Energy, Inc.	9,411,275	16,003,144	704,922	569,873	(932,731)	0	56,248	398,312
293 Elmwood	2,709,268	7,481,524	338,870	168,715	(436,055)	0	16,192	87,722
292 AEP River Operations LLC	31,755,556	82,889,489	5,358,370	2,047,742	(4,831,148)	0	189,792	2,764,756
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$44,834,186**	**$107,418,965**	**$6,402,162**	**$2,840,539**	**($6,260,830)**	**$0**	**$267,958**	**$3,249,829**
270 Cook Coal Terminal	$3,337,585	$4,280,580	$109,999	$191,386	($249,490)	$0	$19,948	$71,843
AEP Generating Company	**$3,337,585**	**$4,280,580**	**$109,999**	**$191,386**	**($249,490)**	**$0**	**$19,948**	**$71,843**
104 Cardinal Operating Company	$69,804,478	$93,237,878	$1,527,887	$3,963,294	($5,434,295)	$0	$417,196	$474,082
181 Ohio Power Co - Generation	270,574,187	373,419,809	3,528,972	15,235,953	(21,764,476)	0	1,617,125	(1,382,426)
AEP Generation Resources - FERC	**$340,378,665**	**$466,657,687**	**$5,056,859**	**$19,199,247**	**($27,198,771)**	**$0**	**$2,034,321**	**($908,344)**
290 Conesville Coal Preparation Company	2,922,431	4,261,325	0	163,763	(248,368)	0	17,466	(67,139)
AEP Generation Resources - SEC	**$343,301,096**	**$470,919,012**	**$5,056,859**	**$19,363,010**	**($27,447,139)**	**$0**	**$2,051,787**	**($975,483)**
Total	**$4,215,072,958**	**$4,790,396,683**	**$99,393,404**	**$239,680,349**	**($279,204,458)**	**$3**	**$25,191,985**	**$85,061,283**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2022 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$289,756,503	$296,539,010	$5,013,079	$16,396,441	($17,298,942)	$0	$1,556,369	$5,666,947
215 Appalachian Power Co - Generation	244,378,594	259,484,970	4,802,338	13,862,462	(15,137,352)	0	1,312,631	4,840,079
150 Appalachian Power Co - Transmission	33,756,879	33,291,532	283,542	1,894,182	(1,942,100)	0	181,318	416,942
Appalachian Power Co. - FERC	**$567,891,976**	**$589,315,512**	**$10,098,959**	**$32,153,085**	**($34,378,394)**	**$0**	**$3,050,318**	**$10,923,968**
225 Cedar Coal Co	3,052,383	4,471,369	0	169,653	(260,842)	0	16,395	(74,794)
Appalachian Power Co. - SEC	**$570,944,359**	**$593,786,881**	**$10,098,959**	**$32,322,738**	**($34,639,236)**	**$0**	**$3,066,713**	**$10,849,174**
211 AEP Texas Central Company - Distribution	$246,166,520	$252,700,759	$5,757,035	$13,965,531	($14,741,587)	$0	$1,322,234	$6,303,213
147 AEP Texas Central Company - Generation	6,450,748	15,829,357	0	361,640	(923,424)	0	34,649	(527,135)
169 AEP Texas Central Company - Transmission	23,883,544	25,530,423	720,016	1,367,652	(1,489,346)	0	128,286	726,608
AEP Texas Central Co.	**$276,500,812**	**$294,060,539**	**$6,477,051**	**$15,694,823**	**($17,154,357)**	**$0**	**$1,485,169**	**$6,502,686**
170 Indiana Michigan Power Co - Distribution	$147,526,376	$153,384,186	$2,859,773	$8,375,418	($8,947,842)	$0	$792,408	$3,079,757
132 Indiana Michigan Power Co - Generation	98,847,779	106,928,966	2,105,244	5,607,854	(6,237,823)	0	530,941	2,006,216
190 Indiana Michigan Power Co - Nuclear	191,787,526	268,517,153	7,642,538	11,057,166	(15,664,255)	0	1,030,148	4,065,597
120 Indiana Michigan Power Co - Transmission	33,401,258	34,812,978	612,729	1,892,444	(2,030,855)	0	179,408	653,726
280 Ind Mich River Transp Lakin	30,210,614	44,437,410	1,231,937	1,748,501	(2,592,307)	0	162,270	550,401
Indiana Michigan Power Co. - FERC	**$501,773,553**	**$608,080,693**	**$14,452,221**	**$28,681,383**	**($35,473,082)**	**$0**	**$2,695,175**	**$10,355,697**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$501,773,553**	**$608,080,693**	**$14,452,221**	**$28,681,383**	**($35,473,082)**	**$0**	**$2,695,175**	**$10,355,697**
110 Kentucky Power Co - Distribution	$64,463,629	$67,241,258	$1,201,444	$3,650,833	($3,922,596)	$0	$346,253	$1,275,934
117 Kentucky Power Co - Generation	31,269,858	31,969,664	442,776	1,762,369	(1,864,987)	0	167,960	508,118
180 Kentucky Power Co - Transmission	6,035,111	7,135,758	171,936	346,212	(416,273)	0	32,416	134,291
600 Kentucky Power Co. - Kammer Actives	4,668,356	6,929,934	228,726	268,984	(404,266)	0	25,075	118,519
701 Kentucky Power Co. - Mitchell Actives	26,441,836	49,160,321	1,262,993	1,530,865	(2,867,823)	0	142,027	68,062
702 Kentucky Power Co. - Mitchell Inactives	20,946,988	26,040,402	0	1,169,080	(1,519,097)	0	112,513	(237,504)
Kentucky Power Co.	**$153,825,778**	**$188,477,337**	**$3,307,875**	**$8,728,343**	**($10,995,042)**	**$0**	**$826,244**	**$1,867,420**
250 Ohio Power Co - Distribution	$384,983,650	$413,463,755	$7,341,380	$21,810,077	($24,119,880)	$0	$2,067,862	$7,099,439
160 Ohio Power Co - Transmission	42,721,542	41,962,997	35,658	2,382,809	(2,447,959)	0	229,470	199,978
Ohio Power Co.	**$427,705,192**	**$455,426,752**	**$7,377,038**	**$24,192,886**	**($26,567,839)**	**$0**	**$2,297,332**	**$7,299,417**
167 Public Service Co of Oklahoma - Distribution	$142,042,410	$153,895,527	$4,317,640	$8,131,818	($8,977,671)	$0	$762,952	$4,234,739
198 Public Service Co of Oklahoma - Generation	70,787,343	80,409,483	2,614,872	4,055,084	(4,690,779)	0	380,220	2,359,397
114 Public Service Co of Oklahoma - Transmission	16,956,560	19,499,619	547,903	972,533	(1,137,533)	0	91,079	473,982
Public Service Co. of Oklahoma	**$229,786,313**	**$253,804,629**	**$7,480,415**	**$13,159,435**	**($14,805,983)**	**$0**	**$1,234,251**	**$7,068,118**
159 Southwestern Electric Power Co - Distribution	$86,193,610	$102,705,038	$3,354,702	$4,950,074	($5,991,416)	$0	$462,972	$2,776,332
168 Southwestern Electric Power Co - Generation	95,126,583	111,242,195	4,070,532	5,483,967	(6,489,440)	0	510,953	3,576,012
161 Southwestern Electric Power Co - Texas - Distribution	46,281,050	49,934,412	1,562,868	2,653,209	(2,912,981)	0	248,589	1,551,685
111 Southwestern Electric Power Co - Texas - Transmission	131,608	128,797	0	7,354	(7,514)	0	707	547
194 Southwestern Electric Power Co - Transmission	13,224,762	17,175,507	486,044	763,890	(1,001,953)	0	71,034	319,015
Southwestern Electric Power Co.	**$240,957,613**	**$281,185,949**	**$9,474,146**	**$13,858,494**	**($16,403,304)**	**$0**	**$1,294,255**	**$8,223,591**
119 AEP Texas North Company - Distribution	60,043,709	61,755,930	1,747,812	3,426,174	(3,602,603)	0	322,513	1,893,896
166 AEP Texas North Company - Generation	18,788,612	21,652,016	0	1,043,511	(1,263,095)	0	100,919	(118,665)
192 AEP Texas North Company - Transmission	8,352,209	9,948,895	328,263	479,709	(580,380)	0	44,862	272,454
AEP Texas North Co.	**$87,184,530**	**$93,356,841**	**$2,076,075**	**$4,949,394**	**($5,446,078)**	**$0**	**$468,294**	**$2,047,685**
230 Kingsport Power Co - Distribution	$12,035,170	$13,047,617	$257,357	$684,245	($761,148)	$0	$64,644	$245,098
260 Kingsport Power Co - Transmission	2,448,256	2,460,300	26,984	137,573	(143,524)	0	13,150	34,183
Kingsport Power Co.	**$14,483,426**	**$15,507,917**	**$284,341**	**$821,818**	**($904,672)**	**$0**	**$77,794**	**$279,281**
210 Wheeling Power Co - Distribution	$13,907,330	$14,788,650	$274,079	$786,864	($862,713)	$0	$74,700	$272,930
200 Wheeling Power Co - Transmission	619,609	646,716	0	34,487	(37,727)	0	3,328	88
Wheeling Power Co.	**$14,526,939**	**$15,435,366**	**$274,079**	**$821,351**	**($900,440)**	**$0**	**$78,028**	**$273,018**
103 American Electric Power Service Corporation	$1,277,638,568	$1,405,440,154	$29,555,094	$72,691,381	($81,987,957)	$0	$6,862,578	$27,121,096
American Electric Power Service Corp	**$1,277,638,568**	**$1,405,440,154**	**$29,555,094**	**$72,691,381**	**($81,987,957)**	**$0**	**$6,862,578**	**$27,121,096**
143 AEP Pro Serv, Inc.	$951,002	$1,058,609	$0	$53,533	($61,755)	$0	$5,108	($3,114)
171 CSW Energy, Inc.	9,341,684	17,100,710	729,265	566,772	(997,589)	0	50,177	348,625
293 Elmwood	2,689,235	7,996,672	350,573	167,800	(466,495)	0	14,445	66,323
292 AEP River Operations LLC	31,520,744	89,711,116	5,543,415	2,050,240	(5,233,400)	0	169,307	2,529,562
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$44,502,665**	**$115,867,107**	**$6,623,253**	**$2,838,345**	**($6,759,239)**	**$0**	**$239,037**	**$2,941,396**
270 Cook Coal Terminal	$3,312,905	$4,341,399	$113,798	$190,213	($253,260)	$0	$17,795	$68,546
AEP Generating Company	**$3,312,905**	**$4,341,399**	**$113,798**	**$190,213**	**($253,260)**	**$0**	**$17,795**	**$68,546**
104 Cardinal Operating Company	$69,288,320	$94,117,557	$1,580,650	$3,937,441	($5,490,455)	$0	$372,168	$399,804
181 Ohio Power Co - Generation	268,573,469	375,519,089	3,650,841	15,157,552	(21,906,335)	0	1,442,588	(1,655,354)
AEP Generation Resources - FERC	**$337,861,789**	**$469,636,646**	**$5,231,491**	**$19,094,993**	**($27,396,790)**	**$0**	**$1,814,756**	**($1,255,550)**
290 Conesville Coal Preparation Company	2,900,821	4,310,574	0	163,227	(251,462)	0	15,581	(72,654)
AEP Generation Resources - SEC	**$340,762,610**	**$473,947,220**	**$5,231,491**	**$19,258,220**	**($27,648,252)**	**$0**	**$1,830,337**	**($1,328,204)**
Total	**$4,183,905,263**	**$4,798,718,784**	**$102,825,836**	**$238,208,824**	**($279,938,741)**	**$0**	**$22,473,002**	**$83,568,921**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2023 NET PERIODIC PENSION COST

Location	Projected Benefit Obligation	Market-Related Value of Assets	Service Cost	Interest Cost	Expected Return on Assets	Amortization of Prior Service Cost	Amortization of Gain/Loss	Net Periodic Pension Cost
140 Appalachian Power Co - Distribution	$288,066,768	$294,032,288	$5,149,389	$16,315,236	($17,174,285)	$0	$1,381,260	$5,671,600
215 Appalachian Power Co - Generation	242,953,484	258,569,033	4,932,918	13,799,740	(15,102,893)	0	1,164,945	4,794,710
150 Appalachian Power Co - Transmission	33,560,023	33,153,238	291,252	1,879,814	(1,936,465)	0	160,918	395,519
Appalachian Power Co. - FERC	**$564,580,275**	**$585,754,559**	**$10,373,559**	**$31,994,790**	**($34,213,643)**	**$0**	**$2,707,123**	**$10,861,829**
225 Cedar Coal Co	3,034,582	4,472,102	0	168,911	(261,213)	0	14,551	(77,751)
Appalachian Power Co. - SEC	**$567,614,857**	**$590,226,661**	**$10,373,559**	**$32,163,701**	**($34,474,856)**	**$0**	**$2,721,674**	**$10,784,078**
211 AEP Texas Central Company - Distribution	$244,730,983	$250,289,452	$5,913,574	$13,907,773	($14,619,287)	$0	$1,173,468	$6,375,528
147 AEP Texas Central Company - Generation	6,413,130	16,338,466	0	363,943	(954,322)	0	30,751	(559,628)
169 AEP Texas Central Company - Transmission	23,744,265	25,651,329	739,594	1,361,667	(1,498,282)	0	113,852	716,831
AEP Texas Central Co.	**$274,888,378**	**$292,279,247**	**$6,653,168**	**$15,633,383**	**($17,071,891)**	**$0**	**$1,318,071**	**$6,532,731**
170 Indiana Michigan Power Co - Distribution	$146,666,066	$152,931,007	$2,937,533	$8,328,014	($8,932,627)	$0	$703,253	$3,036,173
132 Indiana Michigan Power Co - Generation	98,271,342	106,524,755	2,162,488	5,578,597	(6,222,060)	0	471,204	1,990,229
190 Indiana Michigan Power Co - Nuclear	190,669,104	274,113,568	7,850,346	11,006,821	(16,010,842)	0	914,245	3,760,570
120 Indiana Michigan Power Co - Transmission	33,206,476	34,612,002	629,390	1,881,893	(2,021,670)	0	159,223	648,836
280 Ind Mich River Transp Lakin	30,034,438	45,670,906	1,265,434	1,742,935	(2,667,616)	0	144,013	484,766
Indiana Michigan Power Co. - FERC	**$498,847,426**	**$613,852,238**	**$14,845,191**	**$28,538,260**	**($35,854,815)**	**$0**	**$2,391,938**	**$9,920,574**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$498,847,426**	**$613,852,238**	**$14,845,191**	**$28,538,260**	**($35,854,815)**	**$0**	**$2,391,938**	**$9,920,574**
110 Kentucky Power Co - Distribution	$64,087,705	$66,779,412	$1,234,113	$3,634,400	($3,900,553)	$0	$307,296	$1,275,256
117 Kentucky Power Co - Generation	31,087,505	31,541,889	454,816	1,753,747	(1,842,347)	0	149,062	515,278
180 Kentucky Power Co - Transmission	5,999,917	7,242,744	176,611	344,255	(423,045)	0	28,769	126,590
600 Kentucky Power Co. - Kammer Actives	4,641,132	7,037,301	234,945	267,900	(411,045)	0	22,254	114,054
701 Kentucky Power Co. - Mitchell Actives	26,287,638	50,684,597	1,297,335	1,525,110	(2,960,463)	0	126,047	(11,971)
702 Kentucky Power Co. - Mitchell Inactives	20,824,834	25,939,506	0	1,163,304	(1,515,114)	0	99,854	(251,956)
Kentucky Power Co.	**$152,928,731**	**$189,225,449**	**$3,397,820**	**$8,688,716**	**($11,052,567)**	**$0**	**$733,282**	**$1,767,251**
250 Ohio Power Co - Distribution	$382,738,591	$411,506,457	$7,540,999	$21,737,557	($24,035,895)	$0	$1,835,204	$7,077,865
160 Ohio Power Co - Transmission	42,472,408	41,780,747	36,627	2,369,137	(2,440,393)	0	203,652	169,023
Ohio Power Co.	**$425,210,999**	**$453,287,204**	**$7,577,626**	**$24,106,694**	**($26,476,288)**	**$0**	**$2,038,856**	**$7,246,888**
167 Public Service Co of Oklahoma - Distribution	$141,214,080	$154,627,898	$4,435,040	$8,100,231	($9,031,741)	$0	$677,111	$4,180,641
198 Public Service Co of Oklahoma - Generation	70,374,541	80,585,835	2,685,973	4,051,811	(4,706,980)	0	337,441	2,368,245
114 Public Service Co of Oklahoma - Transmission	16,857,677	19,686,598	562,801	969,768	(1,149,885)	0	80,831	463,515
Public Service Co. of Oklahoma	**$228,446,298**	**$254,900,331**	**$7,683,814**	**$13,121,810**	**($14,888,606)**	**$0**	**$1,095,383**	**$7,012,401**
159 Southwestern Electric Power Co - Distribution	$85,690,965	$103,488,131	$3,445,919	$4,944,065	($6,044,692)	$0	$410,882	$2,756,174
168 Southwestern Electric Power Co - Generation	94,571,846	112,345,125	4,181,214	5,466,671	(6,562,025)	0	453,465	3,539,325
161 Southwestern Electric Power Co - Texas - Distribution	46,011,159	50,122,937	1,605,363	2,648,167	(2,927,657)	0	220,620	1,546,493
111 Southwestern Electric Power Co - Texas - Transmission	130,840	129,540	0	7,346	(7,566)	0	627	407
194 Southwestern Electric Power Co - Transmission	13,147,641	17,577,669	499,260	758,306	(1,026,703)	0	63,042	293,905
Southwestern Electric Power Co.	**$239,552,451**	**$283,663,402**	**$9,731,756**	**$13,824,555**	**($16,568,643)**	**$0**	**$1,148,636**	**$8,136,304**
119 AEP Texas North Company - Distribution	59,693,560	61,567,392	1,795,337	3,415,564	(3,596,122)	0	286,226	1,901,005
166 AEP Texas North Company - Generation	18,679,045	21,267,067	0	1,041,780	(1,242,199)	0	89,565	(110,854)
192 AEP Texas North Company - Transmission	8,303,502	10,022,502	337,189	472,211	(585,410)	0	39,815	263,805
AEP Texas North Co.	**$86,676,107**	**$92,856,961**	**$2,132,526**	**$4,929,555**	**($5,423,731)**	**$0**	**$415,606**	**$2,053,956**
230 Kingsport Power Co - Distribution	$11,964,986	$13,053,190	$264,354	$679,045	($762,431)	$0	$57,371	$238,339
260 Kingsport Power Co - Transmission	2,433,978	2,433,747	27,718	137,133	(142,154)	0	11,671	34,368
Kingsport Power Co.	**$14,398,964**	**$15,486,937**	**$292,072**	**$816,178**	**($904,585)**	**$0**	**$69,042**	**$272,707**
210 Wheeling Power Co - Distribution	$13,826,228	$14,661,803	$281,531	$785,382	($856,389)	$0	$66,296	$276,820
200 Wheeling Power Co - Transmission	615,996	632,642	0	34,437	(36,952)	0	2,954	439
Wheeling Power Co.	**$14,442,224**	**$15,294,445**	**$281,531**	**$819,819**	**($893,341)**	**$0**	**$69,250**	**$277,259**
103 American Electric Power Service Corporation	$1,270,187,930	$1,406,790,382	$30,358,724	$72,367,278	($82,169,954)	$0	$6,090,461	$26,646,509
American Electric Power Service Corp	**$1,270,187,930**	**$1,406,790,382**	**$30,358,724**	**$72,367,278**	**($82,169,954)**	**$0**	**$6,090,461**	**$26,646,509**
143 AEP Pro Serv, Inc.	$945,456	$1,063,371	$0	$52,952	($62,111)	$0	$4,533	($4,626)
171 CSW Energy, Inc.	9,287,208	18,272,571	749,095	561,485	(1,067,292)	0	44,531	287,819
293 Elmwood	2,673,552	8,539,749	360,105	166,252	(498,803)	0	12,819	40,373
292 AEP River Operations LLC	31,336,929	97,345,513	5,694,146	2,049,884	(5,685,905)	0	150,258	2,208,383
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$44,243,145**	**$125,221,204**	**$6,803,346**	**$2,830,573**	**($7,314,111)**	**$0**	**$212,141**	**$2,531,949**
270 Cook Coal Terminal	$3,293,586	$4,410,310	$116,892	$190,149	($257,604)	$0	$15,793	$65,230
AEP Generating Company	**$3,293,586**	**$4,410,310**	**$116,892**	**$190,149**	**($257,604)**	**$0**	**$15,793**	**$65,230**
104 Cardinal Operating Company	$68,884,260	$95,140,264	$1,623,630	$3,923,386	($5,557,097)	$0	$330,295	$320,214
181 Ohio Power Co - Generation	267,007,264	378,991,843	3,750,111	15,079,999	(22,136,732)	0	1,280,281	(2,026,341)
AEP Generation Resources - FERC	**$335,891,524**	**$474,132,107**	**$5,373,741**	**$19,003,385**	**($27,693,829)**	**$0**	**$1,610,576**	**($1,706,127)**
290 Conesville Coal Preparation Company	2,883,905	4,389,232	0	162,344	(256,373)	0	13,828	(80,201)
AEP Generation Resources - SEC	**$338,775,429**	**$478,521,339**	**$5,373,741**	**$19,165,729**	**($27,950,202)**	**$0**	**$1,624,404**	**($1,786,328)**
Total	**$4,159,506,525**	**$4,816,016,110**	**$105,621,766**	**$237,196,400**	**($281,301,194)**	**$0**	**$19,944,537**	**$81,461,509**

AMERICAN ELECTRIC POWER
QUALIFIED RETIREMENT PLAN
ESTIMATED 2024 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$287,084,675	$291,813,174	$5,299,235	$16,296,550	($17,066,878)	$0	$1,215,340	$5,744,247
215 Appalachian Power Co - Generation	242,125,193	258,164,484	5,076,465	13,752,448	(15,098,913)	0	1,025,009	4,755,009
150 Appalachian Power Co - Transmission	33,445,609	32,823,656	299,727	1,880,228	(1,919,712)	0	141,588	401,831
Appalachian Power Co. - FERC	**$562,655,477**	**$582,801,314**	**$10,675,427**	**$31,929,226**	**($34,085,503)**	**$0**	**$2,381,937**	**$10,901,087**
225 Cedar Coal Co	3,024,237	4,483,322	0	168,700	(262,210)	0	12,803	(80,707)
Appalachian Power Co. - SEC	**$565,679,714**	**$587,284,636**	**$10,675,427**	**$32,097,926**	**($34,347,713)**	**$0**	**$2,394,740**	**$10,820,380**
211 AEP Texas Central Company - Distribution	$243,896,633	$248,851,465	$6,085,657	$13,902,256	($14,554,235)	$0	$1,032,508	$6,466,186
147 AEP Texas Central Company - Generation	6,391,266	17,044,091	0	359,017	(996,834)	0	27,057	(610,760)
169 AEP Texas Central Company - Transmission	23,663,315	25,832,371	761,116	1,359,965	(1,510,823)	0	100,176	710,434
AEP Texas Central Co.	**$273,951,214**	**$291,727,927**	**$6,846,773**	**$15,621,238**	**($17,061,892)**	**$0**	**$1,159,741**	**$6,565,860**
170 Indiana Michigan Power Co - Distribution	$146,166,044	$152,439,974	$3,023,014	$8,318,754	($8,915,548)	$0	$618,777	$3,044,997
132 Indiana Michigan Power Co - Generation	97,936,310	106,175,677	2,225,415	5,570,344	(6,209,752)	0	414,602	2,000,609
190 Indiana Michigan Power Co - Nuclear	190,019,064	280,328,349	8,078,788	11,001,551	(16,395,181)	0	804,424	3,489,582
120 Indiana Michigan Power Co - Transmission	33,093,267	34,404,879	647,705	1,877,924	(2,012,191)	0	140,097	653,535
280 Ind Mich River Transp Lakin	29,932,043	47,110,186	1,302,258	1,735,287	(2,755,269)	0	126,714	408,990
Indiana Michigan Power Co. - FERC	**$497,146,728**	**$620,459,065**	**$15,277,180**	**$28,503,860**	**($36,287,941)**	**$0**	**$2,104,614**	**$9,597,713**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$497,146,728**	**$620,459,065**	**$15,277,180**	**$28,503,860**	**($36,287,941)**	**$0**	**$2,104,614**	**$9,597,713**
110 Kentucky Power Co - Distribution	$63,869,213	$66,444,989	$1,270,025	$3,631,492	($3,886,077)	$0	$270,383	$1,285,823
117 Kentucky Power Co - Generation	30,981,520	31,144,811	468,051	1,748,451	(1,821,524)	0	131,157	526,135
180 Kentucky Power Co - Transmission	5,979,461	7,353,062	181,750	342,862	(430,048)	0	25,313	119,877
600 Kentucky Power Co. - Kammer Actives	4,625,309	7,162,078	241,782	268,230	(418,879)	0	19,581	110,714
701 Kentucky Power Co. - Mitchell Actives	26,198,017	52,376,994	1,335,087	1,519,674	(3,063,302)	0	110,906	(97,635)
702 Kentucky Power Co. - Mitchell Inactives	20,753,837	25,879,025	0	1,160,540	(1,513,551)	0	87,859	(265,152)
Kentucky Power Co.	**$152,407,357**	**$190,360,959**	**$3,496,695**	**$8,671,249**	**($11,133,381)**	**$0**	**$645,199**	**$1,679,762**
250 Ohio Power Co - Distribution	$381,433,737	$411,306,006	$7,760,439	$21,706,783	($24,055,492)	$0	$1,614,756	$7,026,486
160 Ohio Power Co - Transmission	42,327,609	41,540,858	37,693	2,367,706	(2,429,543)	0	179,189	155,045
Ohio Power Co.	**$423,761,346**	**$452,846,864**	**$7,798,132**	**$24,074,489**	**($26,485,035)**	**$0**	**$1,793,945**	**$7,181,531**
167 Public Service Co of Oklahoma - Distribution	$140,732,645	$155,867,278	$4,564,099	$8,079,103	($9,115,996)	$0	$595,775	$4,122,981
198 Public Service Co of Oklahoma - Generation	70,134,617	81,451,176	2,764,134	4,050,484	(4,763,723)	0	296,907	2,347,802
114 Public Service Co of Oklahoma - Transmission	16,800,205	19,976,626	579,179	967,884	(1,168,346)	0	71,122	449,839
Public Service Co. of Oklahoma	**$227,667,467**	**$257,295,080**	**$7,907,412**	**$13,097,471**	**($15,048,065)**	**$0**	**$963,804**	**$6,920,622**
159 Southwestern Electric Power Co - Distribution	$85,398,823	$105,064,441	$3,546,194	$4,940,893	($6,144,760)	$0	$361,526	$2,703,853
168 Southwestern Electric Power Co - Generation	94,249,426	113,930,617	4,302,886	5,461,577	(6,663,304)	0	398,994	3,500,153
161 Southwestern Electric Power Co - Texas - Distribution	45,854,295	50,664,121	1,652,079	2,646,415	(2,963,123)	0	194,119	1,529,490
111 Southwestern Electric Power Co - Texas - Transmission	130,394	129,539	0	7,353	(7,576)	0	552	329
194 Southwestern Electric Power Co - Transmission	13,102,818	17,946,229	513,788	748,257	(1,049,597)	0	55,469	267,917
Southwestern Electric Power Co.	**$238,735,756**	**$287,734,947**	**$10,014,947**	**$13,804,495**	**($16,828,360)**	**$0**	**$1,010,660**	**$8,001,742**
119 AEP Texas North Company - Distribution	59,490,049	61,628,809	1,847,581	3,410,630	(3,604,400)	0	251,844	1,905,655
166 AEP Texas North Company - Generation	18,615,363	21,028,496	0	1,033,365	(1,229,865)	0	78,806	(117,694)
192 AEP Texas North Company - Transmission	8,275,194	9,915,639	347,001	476,720	(579,922)	0	35,032	278,831
AEP Texas North Co.	**$86,380,606**	**$92,572,944**	**$2,194,582**	**$4,920,715**	**($5,414,187)**	**$0**	**$365,682**	**$2,066,792**
230 Kingsport Power Co - Distribution	$11,924,195	$13,008,553	$272,047	$679,505	($760,813)	$0	$50,480	$241,219
260 Kingsport Power Co - Transmission	2,425,680	2,431,994	28,525	136,903	(142,237)	0	10,269	33,460
Kingsport Power Co.	**$14,349,875**	**$15,440,547**	**$300,572**	**$816,408**	**($903,050)**	**$0**	**$60,749**	**$274,679**
210 Wheeling Power Co - Distribution	$13,779,091	$14,637,037	$289,724	$784,424	($856,056)	$0	$58,332	$276,424
200 Wheeling Power Co - Transmission	613,896	623,557	0	34,468	(36,469)	0	2,599	598
Wheeling Power Co.	**$14,392,987**	**$15,260,594**	**$289,724**	**$818,892**	**($892,525)**	**$0**	**$60,931**	**$277,022**
103 American Electric Power Service Corporation	$1,265,857,535	$1,411,185,674	$31,242,153	$72,209,558	($82,534,087)	$0	$5,358,858	$26,276,483
American Electric Power Service Corp	**$1,265,857,535**	**$1,411,185,674**	**$31,242,153**	**$72,209,558**	**($82,534,087)**	**$0**	**$5,358,858**	**$26,276,483**
143 AEP Pro Serv, Inc.	$942,233	$1,058,721	$0	$52,785	($61,920)	$0	$3,989	($5,146)
171 CSW Energy, Inc.	9,255,545	19,413,502	770,893	553,516	(1,135,411)	0	39,182	228,180
293 Elmwood	2,664,438	9,080,845	370,584	166,075	(531,099)	0	11,280	16,840
292 AEP River Operations LLC	31,230,093	105,646,882	5,859,843	2,046,617	(6,178,825)	0	132,209	1,859,844
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$44,092,309**	**$135,199,950**	**$7,001,320**	**$2,818,993**	**($7,907,255)**	**$0**	**$186,660**	**$2,099,718**
270 Cook Coal Terminal	$3,282,357	$4,518,890	$120,293	$190,243	($264,290)	$0	$13,895	$60,141
AEP Generating Company	**$3,282,357**	**$4,518,890**	**$120,293**	**$190,243**	**($264,290)**	**$0**	**$13,895**	**$60,141**
104 Cardinal Operating Company	$68,649,416	$96,516,687	$1,670,877	$3,914,385	($5,644,839)	$0	$290,619	$231,042
181 Ohio Power Co - Generation	266,096,968	383,026,207	3,859,238	15,060,408	(22,401,530)	0	1,126,491	(2,355,393)
AEP Generation Resources - FERC	**$334,746,384**	**$479,542,894**	**$5,530,115**	**$18,974,793**	**($28,046,369)**	**$0**	**$1,417,110**	**($2,124,351)**
290 Conesville Coal Preparation Company	2,874,073	4,476,038	0	161,873	(261,784)	0	12,167	(87,744)
AEP Generation Resources - SEC	**$337,620,457**	**$484,018,932**	**$5,530,115**	**$19,136,666**	**($28,308,153)**	**$0**	**$1,429,277**	**($2,212,095)**
Total	**$4,145,325,708**	**$4,845,907,009**	**$108,695,325**	**$236,782,203**	**($283,415,934)**	**$0**	**$17,548,755**	**$79,610,350**

Non-Reliance Notice for Attachment to Reports Distributed to Third Parties

NOTICE

By accepting a copy of this report, the Recipient agrees that it has read and understands the following:

1. Towers Watson Delaware Inc. ("Towers Watson") represents and is responsible exclusively to its client, AEP with respect to all matters relating to this report. There are no third-party beneficiaries of this report or the work underlying it.

2. Recipient is responsible for its own due diligence with respect to all matters relating to this report.

Recipient is **DEEMED TO HAVE AGREED** to the following conditions by receiving, downloading, printing or otherwise having possession of this report:

- Recipient recognizes that Towers Watson's consulting staff is available, with AEP prior consent and at AEP expense, to answer any questions concerning this report; and

- Recipient agrees that by accepting this report (including any information related to the report that may be subsequently provided to Recipient by or on behalf of Towers Watson), Recipient will place no reliance on this report or information contained herein, or related hereto, that would result in the creation of any duty or liability by Towers Watson to Recipient.

American Electric Power

Excess Benefit Plan

Actuarial Valuation Report

Pension Cost for Fiscal Year Ending December 31, 2014 under US GAAP

April 2014

TOWERS WATSON

Table of Contents

This page is intentionally blank

Purpose and actuarial statement

As requested by American Electric Power (the Company or AEP), this report documents the results of an actuarial valuation of the American Electric Power Excess Benefit Plan (the Plan)

The primary purpose of this valuation is to determine the Net Periodic Benefit Cost/(Income) (Benefit Cost), in accordance with FASB Accounting Standards Codification Topic 715 (ASC 715) for the fiscal year beginning January 1, 2014. It is anticipated that a separate report will be prepared for year-end disclosure purposes.

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for deferred taxes. Any such deferred tax allowance should be made in consultation with the Company's tax advisors and auditors.

This report is provided subject to the terms set out herein and in our master consulting services agreement dated July 29, 2004 and the accompanying General Terms and Conditions of Business. This report is provided solely for the Company's use and for the specific purposes indicated above. It may not be suitable for use in any other context or for any other purpose.

Except where we expressly agree in writing, this report should not be disclosed or provided to any third party, other than as provided below. In the absence of such consent and an express assumption of responsibility, no responsibility whatsoever is accepted by us for any consequences arising from any third party relying on this report or any advice relating to its contents.

The Company may make a copy of this report available to its auditors, but we make no representation as to the suitability of this report for any purpose other than that for which it was originally provided and accept no responsibility or liability to the Company's auditors in this regard. The Company should draw the provisions of this paragraph to the attention of its auditors when passing this report to them.

In preparing these results, we have relied upon information and data provided to us orally and in writing by AEP and other persons or organizations designated by AEP. We have relied on all the data and information provided, including Plan provisions, membership data and asset information, as being complete and accurate. We have not independently verified the accuracy or completeness of the data or information provided, but we have performed limited checks for consistency.

The results summarized in this report involve actuarial calculations that require assumptions about future events. AEP is responsible for the selection of the assumptions.

As required by U.S. GAAP, the actuarial assumptions and methods employed in the development of the pension cost have been selected by the plan sponsor. Towers Watson has concurred with these assumptions and methods. ASC 715-30-35 requires that each significant assumption "individually represent the best estimate of a particular future event."

In our opinion, all calculations are in accordance with US GAAP and the procedures followed and the results presented are in conformity with applicable actuarial standards of practice.

The undersigned consulting actuaries are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to pension plans. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Delaware Inc.

Joseph A. Perko, FSA, EA, MAAA
Senior Consultant

Ryan S. Carney

Ryan S. Carney, FSA, EA, MAAA
Senior Consultant

Towers Watson Delaware Inc.

April 2014

Section 1: Summary of key results

Benefit cost, assets & obligations

All monetary amounts shown in US Dollars

Fiscal Year Beginning		January 1, 2014	January 1, 2013
Benefit Cost/ (Income)	Net Periodic Benefit Cost/(Income)	6,402,078	7,353,696
	Immediate Recognition of Benefit Cost/(Income) due to Special Events	0	0
	Total Benefit Cost/(Income)	6,402,078	7,353,696
Measurement Date		**January 1, 2014**	**January 1, 2013**
Plan Assets	Fair Value of Assets (FVA)	0	0
	Market Related Value of Assets (MRVA)	0	0
	Return on Fair Value Assets during Prior Year	N/A	N/A
Benefit Obligations	Accumulated Benefit Obligation (ABO)	(74,774,033)	(84,704,119)
	Projected Benefit Obligation (PBO)	(76,771,087)	(86,575,004)
Funded Ratios	Fair Value of Assets to ABO	0.0%	0.0%
	Fair Value of Assets to PBO	0.0%	0.0%
Accumulated Other Comprehensive (Income)/Loss	Net Prior Service Cost/(Credit)	179,858	478,655
	Net Loss/(Gain)	33,456,219	43,841,210
	Total Accumulated Other Comprehensive (Income)/Loss	33,636,077	44,319,865
Assumptions[1]	Discount Rate	4.55%	3.80%
	Expected Long-term Rate of Return on Plan Assets	N/A	N/A
	Rate of Compensation Increase	Rates vary by age from 3.5% to 11.5%	Rates vary by age from 3.5% to 11.5%
Participant Data	Census Date	January 1, 2014	January 1, 2013

[1] Rates are expressed on an annual basis where applicable.

Comments on results

The pension cost declined from $7,353,696 in fiscal 2013 to $6,402,078 in fiscal 2014, as set forth below:

All monetary amounts shown in US Dollars

	Pension Cost
Prior year	7,353,696
Change due to:	
► Expected based on prior valuation and payments during the prior year	(632,187)
► Unexpected noninvestment experience	(183,515)
► Unexpected investment experience	0
► Assumption changes	(135,916)
► Plan amendments	0
► Method change	0
► Interim events	0
Current year	6,402,078

Significant reasons for these changes include the following:

- The discount rate increased 75 basis points compared to the prior year, which decreased the pension cost.
- Demographic experience was more favorable than expected which decreased the pension cost.

Plan provisions and assumptions

Appendix A outlines the assumptions and methods used in the valuation. Appendix B outlines our understanding of the principal provisions of the Plan being valued.

Changes in assumptions

The discount rate decreased from 3.80% to 4.55%.

The mortality table used to value the benefit obligations was updated from the RP2000 with projections to 2020 for annuitants and to 2028 for nonannuitants to RP2000 with projections to 2021 for annuitants and to 2029 for nonannuitants.

The lump sum conversion rate increased from 5.10% to 5.90%.

The mortality used to convert to 417(e) based forms of payment was updated for an additional year of mortality improvements.

Changes in methods

None.

Changes in benefits valued

None.

This page is intentionally blank

Section 2: Accounting exhibits

2.1 Balance sheet asset/(liability)

All monetary amounts shown in US Dollars

Measurement Date			01/01/2014	01/01/2013
A	**Development of Balance Sheet Asset/(Liability)**[1]			
	1	Projected benefit obligation (PBO)[2]	(76,771,087)	(86,575,004)
	2	Fair value of assets (FVA)	0	0
	3	Net balance sheet asset/(liability)	(76,771,087)	(86,575,004)
B	**Current and Noncurrent Allocation**[3]			
	1	Noncurrent assets	0	0
	2	Current liabilities	(8,743,143)	(7,943,073)
	3	Noncurrent liabilities	(68,027,944)	(78,631,931)
	4	Net balance sheet asset/(liability)	(76,771,087)	(86,575,004)
C	**Accumulated Benefit Obligation (ABO)**		(74,774,033)	(84,704,119)
D	**Accumulated Other Comprehensive (Income)/Loss**			
	1	Net prior service cost/(credit)	179,858	478,655
	2	Net loss/(gain)	33,456,219	43,841,210
	3	Accumulated other comprehensive (income)/loss[3]	33,636,077	44,319,865
E	**Assumptions and Dates**[4]			
	1	Discount rate	4.55%	3.80%
	2	Rate of compensation increase	Rates vary by age from 3.5% to 11.5%	Rates vary by age from 3.5% to 11.5%
	3	Census date	January 1, 2014	January 1, 2013

[1] Whether the amounts in this table that differ from those disclosed at year-end must be disclosed in subsequent interim financial statements should be determined.
[2] East PBO = $44,112,394; West PBO = $32,658,693.
[3] Amount shown is pre-tax and should be adjusted by plan sponsor for tax effects. .
[4] Rates we expressed on an annual basis where applicable.

2.2 Summary and comparison of benefit cost and cash flows

All monetary amounts shown in US Dollars

	Fiscal Year Ending	December 31, 2014	December 31, 2013
A	**Total Benefit Cost**		
	1 Employer service cost	509,338	547,672
	2 Interest cost	3,319,565	3,161,150
	3 Expected return on assets	0	0
	4 Subtotal	3,828,903	3,708,822
	5 Net prior service cost/(credit) amortization	35,541	298,793
	6 Net loss/(gain) amortization	2,537,634	3,346,081
	7 Amortization subtotal	2,573,175	3,644,874
	8 Net periodic benefit cost/(income)	6,402,078	7,353,696
	9 Curtailments	0	0
	10 Settlements	0	0
	11 Special/contractual termination benefits	0	0
	12 Total benefit cost	6,402,078	7,353,696
B	**Assumptions**[1]		
	1 Discount rate	4.55%	3.80%
	2 Rate of return on assets	N/A	N/A
	3 Rate of compensation increase	Rates vary by age from 3.5% to 11.5%	Rates vary by age from 3.5% to 11.5%
	4 Census date	January 1, 2014	January 1, 2013
C	**Assets at Beginning of Year**		
	1 Fair market value	0	0
	2 Market-related value	0	0
D	**Cash Flow**	**Expected**	**Actual**
	1 Employer contributions	0	0
	2 Plan participants' contributions[2]	0	0
	3 Benefits paid from the Company	8,743,143	6,475,259
	4 Benefits paid from plan assets[2]	0	0

[1] These assumptions were used to calculate Net Periodic Benefit Cost/(Income) as of the beginning of the year. Rates are expressed on an annual basis where applicable. For assumptions used for interim measurement periods, if any, refer to Appendix A.

[2] Over the fiscal year.

Section 3: Data exhibits

3.1 Plan participant data

All monetary amounts shown in US Dollars

Census Date		January 1, 2014	January 1, 2013
A	**Participating Employees**		
	1 Number	17,684	17,631
	2 Total annual plan compensation	1,624,739,458	1,592,436,325
	3 Average plan compensation	91,876	90,320
	4 Average age (years)	47.5	46.8
	5 Average credited service (years)	18.0	17.3
	6 Average future working life (years)	10.159	10.5149
B	**Participants with Deferred Benefits**		
	1 Number (non-cash balance)	2	2
	2 Total annual pension (non-cash balance)	8,018	240,580
	3 Average annual pension (non-cash balance)	4,009	120,290
	4 Number of cash balance	2	2
	5 Total cash balance	422,671	406,415
	6 Average cash balance	211,336	203,208
	7 Average age	61.9	60.0
C	**Participants Receiving Benefits**		
	1 Number	94	93
	2 Total annual pension	5,776,198	6,972,897
	3 Average annual pension	61,449	74,977
	4 Average age (years)	73.1	72.5

This page is intentionally blank

Appendix A : Statement of actuarial assumptions and methods

Actuarial Assumptions and Methods — Pension Cost

Economic Assumptions

Discount rate 4.55%

Annual rates of increase

- Compensation:
  - Representative rates

	Age	*Rate*
	< 26	11.50%
	26 – 30	9.50%
	31 – 35	7.50%
	36 – 40	6.50%
	41 – 45	5.00%
	46 – 50	4.00%
	> 50	3.50%

  - Weighted average
- Cash balance crediting rate 4.00%
- Lump sum/annuity conversion rate 5.90%
- Future Social Security wage bases 4.00%
- Statutory limits on compensation 3.00%

Demographic Assumptions

Inclusion Date — The valuation date coincident with or next following the date on which the employee becomes a participant.

New or rehired employees — It was assumed there will be no new or rehired employees.

Mortality

- Healthy — Separate rates for (1) non-annuitants (based on RP-2000 “Employees” table without collar or amount adjustments, projected to 2029 using Scale AA and (2) annuitants (based on RP-2000 “Healthy Annuitants” table without collar or amount adjustments, projected to 2021 using Scale AA.
- Disabled — RP2000 – disabled retirees, no projection.
- Lump sum/annuity conversion — Applicable 417(e) IRS Mortality Table

Termination — Rates varying by age and service

Percentage leaving during the year		
Attained Age	Less than five years of service	Five or more years of service
< 25	8.00%	8.00%
25 – 29	8.00%	6.00%
30 – 34	8.00%	5.00%
35 – 39	8.00%	3.00%
40 – 49	8.00%	2.50%
> 49	8.00%	4.00%

Disability — Rates apply to employees not eligible to retire and vary by age and sex as indicated by the following sample values:

Percentage becoming disabled during the year		
Age	Male	Female
20	0.060%	0.090%
30	0.060%	0.090%
40	0.074%	0.110%
50	0.178%	0.267%
60	0.690%	1.035%

Retirement	Rates varying by age; average retirement age 61:

Percentage retiring during the year	
Age	Rate
55-57	7.00%
58-60	10.00%
61-63	25.00%
64-65	50.00%
66-69	25.00%
70+	100.00%

Benefit commencement date:	
▸ Preretirement death benefit	The later of the death of the active participant or the date the participant would have attained age 55.
▸ Deferred vested benefit	The later of age 55 or termination of employment.
▸ Disability benefit	Upon disablement.
▸ Retirement benefit	Upon termination of employment.
Form of payment	40% lump sum; 60% annuity for retirement eligible East grandfathered participants and 75% lump sum; 25% annuity for all other participants. Married participants are assumed to elect the 50% joint and survivor annuity and unmarried participants are assumed to elect the single life annuity. No other optional form of payment election is assumed.
Percent married	80% of male participants; 70% of female participants.
Spouse ages	Wives are assumed to be three years younger than husbands.
Valuation pay	2014 base salary pay (Grandfathered) – not estimated due to freeze of final average pay accruals at December 31, 2010. 2014 expanded pay (Cash Balance) – sum of the following updated one year according to the salary increase assumption: (i) 2014 base salary (ii) a 15% increase for overtime eligible employees and a target bonus percent increase for incentive-eligible employees
Timing of benefit payments	Annuity payments are payable monthly at the beginning of the month and lump sum payments are payable on date of decrement.

Methods

Service cost and projected benefit obligation	Projected unit credit
Benefits not valued	All benefits described in the Plan Provisions sections of this report were valued. Towers Watson has reviewed the plan provisions with AEP and is not aware of any significant benefits required to be valued that were not.
Change in assumptions and methods since prior valuation	The discount rate was increased from 3.80% to 4.55%. The mortality table used to value the benefit obligations was updated from the RP2000 with projections to 2020 for annuitants and to 2028 for nonannuitants to RP2000 with projections to 2021 and 2029, respectively. The mortality table used for lump sum/annuity conversions was updated for an additional year of mortality improvements. Accruals were frozen for particpants with LTD status. The lump sum conversion rate was changed from 5.10% to 5.90%.
Data Sources	Towers Watson used participant and asset data as of January 1, 2014, supplied by ACS, the third party database for the AEP pension data with the exception of certain data records that were not provided on the original file but are due benefits. The data for such exceptions was collected from the ACS system. Data were reviewed for reasonabless and consistency, but no audit was performed. Assumptions or estimates were made by Towers Watson actuaries when data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Appendix B : Summary of principal plan provisions

The Excess Benefit Plan provides a benefit determined in accordance with the provisions of the American Electric Power System's Retirement Plan (a qualified defined benefit plan), without recognition of the statutory maximums on benefits and pay, less the benefit payable from the qualified plan. MICP awards are also included in the definition of pay for the former East Plan grandfathered benefit for executives with base pay in excess of the IRS limit. Certain executives have contracts providing additional benefits. Certain former Central and South West company executives are eligible for a final average pay cash balance benefit (pension equity – type formula) if it produces a larger benefit. The schedule of contribution percentages for this formula is identical to the cash balance formula.

Prior to 2004, all executives had their cash balance pay limited to $1,000,000. In addition, pay was limited for executives in an uncapped incentive plan to two times base pay for both the final average pay formula and the cash balance formula. Base pay rate is determined at the earlier of year-end or date of termination.

Effective January 1, 2004, pay for all executives is limited to the greater of two times base pay or $1 million for the cash balance formula only. The executives in the uncapped incentive plan continue to have two times pay limit apply to the former East Plan final average pay formula.

Effective December 31, 2010, accruals under the east grandfathered final average pay formula were discontinued.

Effective December 31, 2013, accruals for participates in long-term disability were discontinued.

Future Plan Changes

Towers Watson is not aware of any future plan changes that are required to be reflected.

Changes in Benefits Valued Since Prior Year

None.

This page is intentionally blank

Appendix C: Results by Business Unit

Summary of key assumptions for Appendix C of 2014 Excess Benefit Plan valuation report:

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Discount Rate	4.55%	5.15%	5.35%	5.45%	5.55%	5.65%	5.65%	5.65%	5.65%	5.65%
Cash balance crediting rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Lump sum conversion rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%

Expected mortality	IRS-prescribed mortality table for minimum funding purposes, with adoption of RP-2014 and projection scale MP-2014 at year end 2015.
Valuation and data	January 1, 2014

AMERICAN ELECTRIC POWER
NONQUALIFIED PENSION PLAN
10-YEAR PENSION COST FORECAST
($000s)

	ASC 715-30 Cost	Estimated Net Periodic Pension Cost									
Location	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
140 Appalachian Power Co - Distribution	$54,478	$51,273	$55,382	$54,008	$52,596	$51,574	$50,193	$49,936	$50,015	$49,306	$50,309
215 Appalachian Power Co - Generation	7	7	7	7	5	4	4	5	5	5	5
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**54,485**	**51,280**	**55,389**	**54,015**	**52,601**	**51,578**	**50,197**	**49,941**	**50,020**	**49,311**	**50,314**
225 Cedar Coal Co	0	0	0	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**54,485**	**51,280**	**55,389**	**54,015**	**52,601**	**51,578**	**50,197**	**49,941**	**50,020**	**49,311**	**50,314**
211 AEP Texas Central Company - Distribution	181,014	169,301	184,911	175,386	165,577	156,463	149,074	142,017	135,403	129,615	124,366
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	2	2	1	1	1	1	1	1	1
AEP Texas Central Co.	**181,014**	**169,301**	**184,913**	**175,388**	**165,578**	**156,464**	**149,075**	**142,018**	**135,404**	**129,616**	**124,367**
170 Indiana Michigan Power Co - Distribution	18,745	17,918	19,292	19,219	19,016	18,955	19,061	19,179	19,426	19,752	19,605
132 Indiana Michigan Power Co - Generation	4	4	4	4	0	0	0	0	0	0	0
190 Indiana Michigan Power Co - Nuclear	35,774	33,886	37,283	37,679	37,041	36,449	36,109	36,401	36,725	37,003	37,284
120 Indiana Michigan Power Co - Transmission	8,155	7,518	8,153	7,725	7,280	6,867	6,519	6,190	5,875	5,600	5,348
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**62,678**	**59,326**	**64,732**	**64,627**	**63,337**	**62,271**	**61,689**	**61,770**	**62,026**	**62,355**	**62,237**
202 Price River Coal	0	0	0	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**62,678**	**59,326**	**64,732**	**64,627**	**63,337**	**62,271**	**61,689**	**61,770**	**62,026**	**62,355**	**62,237**
110 Kentucky Power Co - Distribution	239	229	246	249	236	235	237	225	246	250	255
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0	0	0	0
Kentucky Power Co.	**239**	**229**	**246**	**249**	**236**	**235**	**237**	**225**	**246**	**250**	**255**
250 Ohio Power Co - Distribution	22,541	21,664	23,302	23,361	23,410	23,480	23,865	24,309	24,753	25,306	25,989
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0	0	0	0
Ohio Power Co.	**22,541**	**21,664**	**23,302**	**23,361**	**23,410**	**23,480**	**23,865**	**24,309**	**24,753**	**25,306**	**25,989**
167 Public Service Co of Oklahoma - Distribution	165,808	153,921	167,041	158,777	150,951	143,723	137,272	131,146	125,165	120,135	116,038
198 Public Service Co of Oklahoma - Generation	28,977	27,133	29,591	28,025	26,430	24,952	23,676	22,533	21,401	20,415	19,515
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**194,785**	**181,054**	**196,632**	**186,802**	**177,381**	**168,675**	**160,948**	**153,679**	**146,566**	**140,550**	**135,553**
159 Southwestern Electric Power Co - Distribution	71,504	68,151	73,404	72,502	71,914	71,536	70,569	71,574	72,684	72,631	75,050
168 Southwestern Electric Power Co - Generation	73,960	69,020	75,128	71,107	67,054	63,298	60,088	57,063	54,152	51,590	49,290
161 Southwestern Electric Power Co - Texas - Distribution	24	22	23	22	21	19	19	18	17	16	15
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	6,374	5,834	6,311	5,944	5,563	5,205	5,139	5,109	4,848	4,619	4,408
Southwestern Electric Power Co.	**151,862**	**143,027**	**154,866**	**149,575**	**144,552**	**140,058**	**135,815**	**133,764**	**131,701**	**128,856**	**128,763**
119 AEP Texas North Company - Distribution	63,586	59,166	64,436	60,914	57,350	54,065	51,301	48,711	46,234	44,092	42,148
166 AEP Texas North Company - Generation	48,163	44,818	48,725	46,045	43,335	40,823	38,692	36,686	34,759	33,076	31,541
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0	0	0	0
AEP Texas North Co.	**111,749**	**103,984**	**113,161**	**106,959**	**100,685**	**94,888**	**89,993**	**85,397**	**80,993**	**77,168**	**73,689**
230 Kingsport Power Co - Distribution	0	0	0	0	0	0	0	0	0	0	0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0	0	0	0
Kingsport Power Co.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
210 Wheeling Power Co - Distribution	0	0	0	0	0	0	0	0	0	0	0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0	0	0	0
Wheeling Power Co.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
103 American Electric Power Service Corporation	5,261,342	4,925,142	5,356,709	5,067,298	4,797,412	4,566,098	4,376,403	4,194,956	4,032,584	3,892,028	3,760,267
American Electric Power Service Corp	**5,261,342**	**4,925,142**	**5,356,709**	**5,067,298**	**4,797,412**	**4,566,098**	**4,376,403**	**4,194,956**	**4,032,584**	**3,892,028**	**3,760,267**
143 AEP Pro Serv, Inc.	0	0	0	0	0	0	0	0	0	0	0
171 CSW Energy, Inc.	278,364	260,712	281,435	271,058	261,332	251,999	245,395	238,654	233,188	228,615	223,561
293 Elmwood	0	0	0	0	0	0	0	0	0	0	0
189 Central Coal Company	0	0	0	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	16,762	14,976	16,863	17,194	16,656	15,975	15,400	14,641	14,547	14,144	13,791
Miscellaneous	**295,126**	**275,688**	**298,298**	**288,252**	**277,988**	**267,974**	**260,795**	**253,295**	**247,735**	**242,759**	**237,352**
270 Cook Coal Terminal	2	3	3	56	62	69	47	86	97	139	151
AEP Generating Company	**2**	**3**	**3**	**56**	**62**	**69**	**47**	**86**	**97**	**139**	**151**
104 Cardinal Operating Company	398	377	406	405	391	390	393	389	398	405	409
181 Ohio Power Co - Generation	65,858	60,349	65,354	61,806	57,714	54,908	52,079	49,595	47,805	45,860	44,107
AEP Generation Resources - FERC	**66,256**	**60,726**	**65,760**	**62,211**	**58,105**	**55,298**	**52,472**	**49,984**	**48,203**	**46,265**	**44,516**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**66,256**	**60,726**	**65,760**	**62,211**	**58,105**	**55,298**	**52,472**	**49,984**	**48,203**	**46,265**	**44,516**
Total	**$6,402,079**	**$5,991,424**	**$6,514,011**	**$6,178,793**	**$5,861,347**	**$5,587,088**	**$5,361,536**	**$5,149,424**	**$4,960,328**	**$4,794,603**	**$4,643,453**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
2014 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$481,782	$0	$17,057	$21,495	$0	$1	$15,925	$54,478
215 Appalachian Power Co - Generation	21	0	3	1	0	2	1	7
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$481,803**	**$0**	**$17,060**	**$21,496**	**$0**	**$3**	**$15,926**	**$54,485**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$481,803**	**$0**	**$17,060**	**$21,496**	**$0**	**$3**	**$15,926**	**$54,485**
211 AEP Texas Central Company - Distribution	$2,350,877	$0	$4,510	$102,156	$0	($3,359)	$77,707	$181,014
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas Central Co.	**$2,350,877**	**$0**	**$4,510**	**$102,156**	**$0**	**($3,359)**	**$77,707**	**$181,014**
170 Indiana Michigan Power Co - Distribution	$117,696	$0	$9,149	$5,714	$0	($8)	$3,890	$18,745
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	4	0	4
190 Indiana Michigan Power Co - Nuclear	277,833	0	14,934	12,440	0	(784)	9,184	35,774
120 Indiana Michigan Power Co - Transmission	106,989	0	0	4,619	0	0	3,536	8,155
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$502,518**	**$0**	**$24,083**	**$22,773**	**$0**	**($788)**	**$16,610**	**$62,678**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$502,518**	**$0**	**$24,083**	**$22,773**	**$0**	**($788)**	**$16,610**	**$62,678**
110 Kentucky Power Co - Distribution	$1,514	$0	$115	$74	$0	$0	$50	$239
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,514**	**$0**	**$115**	**$74**	**$0**	**$0**	**$50**	**$239**
250 Ohio Power Co - Distribution	$118,180	$0	$12,700	$5,925	$0	$10	$3,906	$22,541
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$118,180**	**$0**	**$12,700**	**$5,925**	**$0**	**$10**	**$3,906**	**$22,541**
167 Public Service Co of Oklahoma - Distribution	$2,072,336	$0	$7,911	$90,752	$0	($1,355)	$68,500	$165,808
198 Public Service Co of Oklahoma - Generation	377,846	0	418	16,588	0	(519)	12,490	28,977
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$2,450,182**	**$0**	**$8,329**	**$107,340**	**$0**	**($1,874)**	**$80,990**	**$194,785**
159 Southwestern Electric Power Co - Distribution	$479,326	$0	$32,963	$22,695	$0	$2	$15,844	$71,504
168 Southwestern Electric Power Co - Generation	962,865	0	775	42,446	0	(1,088)	31,827	73,960
161 Southwestern Electric Power Co - Texas - Distribution	297	0	0	14	0	0	10	24
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	84,985	0	0	3,563	0	2	2,809	6,374
Southwestern Electric Power Co.	**$1,527,473**	**$0**	**$33,738**	**$68,718**	**$0**	**($1,084)**	**$50,490**	**$151,862**
119 AEP Texas North Company - Distribution	844,592	0	0	36,520	0	(852)	27,918	63,586
166 AEP Texas North Company - Generation	634,079	0	0	27,751	0	(547)	20,959	48,163
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,478,671**	**$0**	**$0**	**$64,271**	**$0**	**($1,399)**	**$48,877**	**$111,749**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$63,925,209	$0	$354,486	$2,749,366	$0	$44,471	$2,113,019	$5,261,342
American Electric Power Service Corp	**$63,925,209**	**$0**	**$354,486**	**$2,749,366**	**$0**	**$44,471**	**$2,113,019**	**$5,261,342**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,900,535	0	48,777	133,288	0	423	95,876	278,364
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	205,929	0	2,074	8,670	0	(789)	6,807	16,762
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$3,106,464**	**$0**	**$50,851**	**$141,958**	**$0**	**($366)**	**$102,683**	**$295,126**
270 Cook Coal Terminal	$0	$0	$0	$2	$0	$0	$0	$2
AEP Generating Company	**$0**	**$0**	**$0**	**$2**	**$0**	**$0**	**$0**	**$2**
104 Cardinal Operating Company	$2,987	$0	$163	$139	$0	($3)	$99	$398
181 Ohio Power Co - Generation	825,209	0	3,303	35,348	0	(70)	27,277	65,858
AEP Generation Resources - FERC	**$828,196**	**$0**	**$3,466**	**$35,487**	**$0**	**($73)**	**$27,376**	**$66,256**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$828,196**	**$0**	**$3,466**	**$35,487**	**$0**	**($73)**	**$27,376**	**$66,256**
Total	**$76,771,087**	**$0**	**$509,338**	**$3,319,566**	**$0**	**$35,541**	**$2,537,634**	**$6,402,079**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2015 NET PERIODIC PENSION COST

Location	Projected Benefit Obligation	Market-Related Value of Assets	Service Cost	Interest Cost	Expected Return on Assets	Amortization of Prior Service Cost	Amortization of Gain/Loss	Net Periodic Pension Cost
140 Appalachian Power Co - Distribution	$429,175	$0	$16,721	$21,563	$0	$1	$12,988	$51,273
215 Appalachian Power Co - Generation	19	0	3	1	0	2	1	7
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$429,194**	**$0**	**$16,724**	**$21,564**	**$0**	**$3**	**$12,989**	**$51,280**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$429,194**	**$0**	**$16,724**	**$21,564**	**$0**	**$3**	**$12,989**	**$51,280**
211 AEP Texas Central Company - Distribution	$2,094,178	$0	$4,421	$102,450	$0	($947)	$63,377	$169,301
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas Central Co.	**$2,094,178**	**$0**	**$4,421**	**$102,450**	**$0**	**($947)**	**$63,377**	**$169,301**
170 Indiana Michigan Power Co - Distribution	$104,844	$0	$8,969	$5,784	$0	($8)	$3,173	$17,918
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	4	0	4
190 Indiana Michigan Power Co - Nuclear	247,496	0	14,640	12,540	0	(784)	7,490	33,886
120 Indiana Michigan Power Co - Transmission	95,307	0	0	4,634	0	0	2,884	7,518
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$447,647**	**$0**	**$23,609**	**$22,958**	**$0**	**($788)**	**$13,547**	**$59,326**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$447,647**	**$0**	**$23,609**	**$22,958**	**$0**	**($788)**	**$13,547**	**$59,326**
110 Kentucky Power Co - Distribution	$1,349	$0	$113	$75	$0	$0	$41	$229
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,349**	**$0**	**$113**	**$75**	**$0**	**$0**	**$41**	**$229**
250 Ohio Power Co - Distribution	$105,276	$0	$12,450	$6,018	$0	$10	$3,186	$21,664
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$105,276**	**$0**	**$12,450**	**$6,018**	**$0**	**$10**	**$3,186**	**$21,664**
167 Public Service Co of Oklahoma - Distribution	$1,846,051	$0	$7,755	$91,281	$0	($983)	$55,868	$153,921
198 Public Service Co of Oklahoma - Generation	336,588	0	410	16,671	0	(134)	10,186	27,133
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$2,182,639**	**$0**	**$8,165**	**$107,953**	**$0**	**($1,117)**	**$66,054**	**$181,055**
159 Southwestern Electric Power Co - Distribution	$426,987	$0	$32,314	$22,913	$0	$2	$12,922	$68,151
168 Southwestern Electric Power Co - Generation	857,727	0	760	42,609	0	(307)	25,958	69,020
161 Southwestern Electric Power Co - Texas - Distribution	265	0	0	14	0	0	8	22
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	75,705	0	0	3,541	0	2	2,291	5,834
Southwestern Electric Power Co.	**$1,360,684**	**$0**	**$33,074**	**$69,076**	**$0**	**($303)**	**$41,179**	**$143,026**
119 AEP Texas North Company - Distribution	752,368	0	0	36,590	0	(193)	22,769	59,166
166 AEP Texas North Company - Generation	564,842	0	0	27,826	0	(102)	17,094	44,818
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,317,210**	**$0**	**$0**	**$64,416**	**$0**	**($295)**	**$39,863**	**$103,984**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$56,945,022	$0	$347,505	$2,791,562	$0	$62,724	$1,723,349	$4,925,140
American Electric Power Service Corp	**$56,945,022**	**$0**	**$347,505**	**$2,791,562**	**$0**	**$62,724**	**$1,723,349**	**$4,925,140**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,583,817	0	47,816	134,278	0	423	78,195	260,712
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	183,443	0	2,033	8,180	0	(789)	5,552	14,976
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,767,260**	**$0**	**$49,849**	**$142,459**	**$0**	**($366)**	**$83,747**	**$275,689**
270 Cook Coal Terminal	$0	$0	$0	$3	$0	$0	$0	$3
AEP Generating Company	**$0**	**$0**	**$0**	**$3**	**$0**	**$0**	**$0**	**$3**
104 Cardinal Operating Company	$2,661	$0	$160	$139	$0	($3)	$81	$377
181 Ohio Power Co - Generation	735,102	0	3,238	34,934	0	(70)	22,247	60,349
AEP Generation Resources - FERC	**$737,763**	**$0**	**$3,398**	**$35,073**	**$0**	**($73)**	**$22,328**	**$60,726**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$737,763**	**$0**	**$3,398**	**$35,073**	**$0**	**($73)**	**$22,328**	**$60,726**
Total	**$68,388,222**	**$0**	**$499,308**	**$3,363,607**	**$0**	**$58,848**	**$2,069,660**	**$5,991,423**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2016 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$435,357	$0	$17,905	$22,810	$0	$1	$14,666	$55,382
215 Appalachian Power Co - Generation	19	0	3	1	0	2	1	7
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$435,376**	**$0**	**$17,908**	**$22,811**	**$0**	**$3**	**$14,667**	**$55,389**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$435,376**	**$0**	**$17,908**	**$22,811**	**$0**	**$3**	**$14,667**	**$55,389**
211 AEP Texas Central Company - Distribution	$2,124,345	$0	$4,734	$108,282	$0	$333	$71,562	$184,911
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	2	0	0	0	2
AEP Texas Central Co.	**$2,124,345**	**$0**	**$4,734**	**$108,284**	**$0**	**$333**	**$71,562**	**$184,913**
170 Indiana Michigan Power Co - Distribution	$106,355	$0	$9,604	$6,111	$0	($6)	$3,583	$19,292
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	4	0	4
190 Indiana Michigan Power Co - Nuclear	251,061	0	15,677	13,869	0	(720)	8,457	37,283
120 Indiana Michigan Power Co - Transmission	96,679	0	0	4,896	0	0	3,257	8,153
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$454,095**	**$0**	**$25,281**	**$24,876**	**$0**	**($722)**	**$15,297**	**$64,732**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$454,095**	**$0**	**$25,281**	**$24,876**	**$0**	**($722)**	**$15,297**	**$64,732**
110 Kentucky Power Co - Distribution	$1,368	$0	$121	$79	$0	$0	$46	$246
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,368**	**$0**	**$121**	**$79**	**$0**	**$0**	**$46**	**$246**
250 Ohio Power Co - Distribution	$106,792	$0	$13,332	$6,363	$0	$10	$3,597	$23,302
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$106,792**	**$0**	**$13,332**	**$6,363**	**$0**	**$10**	**$3,597**	**$23,302**
167 Public Service Co of Oklahoma - Distribution	$1,872,645	$0	$8,304	$96,071	$0	($417)	$63,083	$167,041
198 Public Service Co of Oklahoma - Generation	341,437	0	439	17,603	0	47	11,502	29,591
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$2,214,082**	**$0**	**$8,743**	**$113,674**	**$0**	**($370)**	**$74,585**	**$196,632**
159 Southwestern Electric Power Co - Distribution	$433,138	$0	$34,603	$24,208	$0	$2	$14,591	$73,404
168 Southwestern Electric Power Co - Generation	870,083	0	814	44,905	0	99	29,310	75,128
161 Southwestern Electric Power Co - Texas - Distribution	268	0	0	14	0	0	9	23
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	76,796	0	0	3,722	0	2	2,587	6,311
Southwestern Electric Power Co.	**$1,380,285**	**$0**	**$35,417**	**$72,849**	**$0**	**$103**	**$46,497**	**$154,866**
119 AEP Texas North Company - Distribution	763,207	0	0	38,604	0	122	25,710	64,436
166 AEP Texas North Company - Generation	572,979	0	0	29,325	0	98	19,302	48,725
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,336,186**	**$0**	**$0**	**$67,929**	**$0**	**$220**	**$45,012**	**$113,161**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$57,765,344	$0	$372,118	$2,967,627	$0	$71,040	$1,945,919	$5,356,704
American Electric Power Service Corp	**$57,765,344**	**$0**	**$372,118**	**$2,967,627**	**$0**	**$71,040**	**$1,945,919**	**$5,356,704**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,621,038	0	51,203	141,515	0	423	88,294	281,435
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	186,086	0	2,177	9,167	0	(750)	6,269	16,863
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,807,124**	**$0**	**$53,380**	**$150,683**	**$0**	**($327)**	**$94,563**	**$298,299**
270 Cook Coal Terminal	$0	$0	$0	$3	$0	$0	$0	$3
AEP Generating Company	**$0**	**$0**	**$0**	**$3**	**$0**	**$0**	**$0**	**$3**
104 Cardinal Operating Company	$2,699	$0	$171	$147	$0	($3)	$91	$406
181 Ohio Power Co - Generation	745,691	0	3,467	36,832	0	(65)	25,120	65,354
AEP Generation Resources - FERC	**$748,390**	**$0**	**$3,638**	**$36,979**	**$0**	**($68)**	**$25,211**	**$65,760**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$748,390**	**$0**	**$3,638**	**$36,979**	**$0**	**($68)**	**$25,211**	**$65,760**
Total	**$69,373,387**	**$0**	**$534,672**	**$3,572,159**	**$0**	**$70,222**	**$2,336,956**	**$6,514,009**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2017 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$417,680	$0	$18,587	$22,167	$0	$1	$13,253	$54,008
215 Appalachian Power Co - Generation	18	0	3	1	0	2	1	7
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$417,698**	**$0**	**$18,590**	**$22,169**	**$0**	**$3**	**$13,254**	**$54,016**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$417,698**	**$0**	**$18,590**	**$22,169**	**$0**	**$3**	**$13,254**	**$54,016**
211 AEP Texas Central Company - Distribution	$2,038,089	$0	$4,914	$105,736	$0	$65	$64,671	$175,386
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	2	0	0	0	2
AEP Texas Central Co.	**$2,038,089**	**$0**	**$4,914**	**$105,739**	**$0**	**$65**	**$64,671**	**$175,389**
170 Indiana Michigan Power Co - Distribution	$102,036	$0	$9,970	$5,996	$0	$15	$3,238	$19,219
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	4	0	4
190 Indiana Michigan Power Co - Nuclear	240,867	0	16,273	13,590	0	173	7,643	37,679
120 Indiana Michigan Power Co - Transmission	92,754	0	0	4,782	0	0	2,943	7,725
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$435,657**	**$0**	**$26,243**	**$24,367**	**$0**	**$192**	**$13,824**	**$64,626**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$435,657**	**$0**	**$26,243**	**$24,367**	**$0**	**$192**	**$13,824**	**$64,626**
110 Kentucky Power Co - Distribution	$1,313	$0	$125	$78	$0	$4	$42	$249
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,313**	**$0**	**$125**	**$78**	**$0**	**$4**	**$42**	**$249**
250 Ohio Power Co - Distribution	$102,456	$0	$13,839	$6,261	$0	$10	$3,251	$23,361
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$102,456**	**$0**	**$13,839**	**$6,261**	**$0**	**$10**	**$3,251**	**$23,361**
167 Public Service Co of Oklahoma - Distribution	$1,796,608	$0	$8,620	$93,195	$0	($46)	$57,008	$158,777
198 Public Service Co of Oklahoma - Generation	327,573	0	455	17,169	0	7	10,394	28,025
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$2,124,181**	**$0**	**$9,075**	**$110,364**	**$0**	**($39)**	**$67,402**	**$186,802**
159 Southwestern Electric Power Co - Distribution	$415,551	$0	$35,919	$23,397	$0	$0	$13,186	$72,502
168 Southwestern Electric Power Co - Generation	834,754	0	845	43,755	0	19	26,488	71,107
161 Southwestern Electric Power Co - Texas - Distribution	257	0	0	14	0	0	8	22
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	73,678	0	0	3,606	0	0	2,338	5,944
Southwestern Electric Power Co.	**$1,324,240**	**$0**	**$36,764**	**$70,772**	**$0**	**$19**	**$42,020**	**$149,575**
119 AEP Texas North Company - Distribution	732,218	0	0	37,663	0	17	23,234	60,914
166 AEP Texas North Company - Generation	549,714	0	0	28,590	0	12	17,443	46,045
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,281,932**	**$0**	**$0**	**$66,253**	**$0**	**$29**	**$40,677**	**$106,959**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$55,419,849	$0	$386,277	$2,907,913	$0	$14,583	$1,758,526	$5,067,299
American Electric Power Service Corp	**$55,419,849**	**$0**	**$386,277**	**$2,907,913**	**$0**	**$14,583**	**$1,758,526**	**$5,067,299**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,514,614	0	53,151	137,693	0	423	79,791	271,058
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	178,530	0	2,260	9,470	0	(201)	5,665	17,194
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,693,144**	**$0**	**$55,411**	**$147,162**	**$0**	**$222**	**$85,456**	**$288,251**
270 Cook Coal Terminal	$0	$0	$0	$56	$0	$0	$0	$56
AEP Generating Company	**$0**	**$0**	**$0**	**$56**	**$0**	**$0**	**$0**	**$56**
104 Cardinal Operating Company	$2,590	$0	$178	$145	$0	$0	$82	$405
181 Ohio Power Co - Generation	715,414	0	3,599	35,506	0	0	22,701	61,806
AEP Generation Resources - FERC	**$718,004**	**$0**	**$3,777**	**$35,650**	**$0**	**$0**	**$22,783**	**$62,210**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$718,004**	**$0**	**$3,777**	**$35,650**	**$0**	**$0**	**$22,783**	**$62,210**
Total	**$66,556,563**	**$0**	**$555,015**	**$3,496,784**	**$0**	**$15,088**	**$2,111,906**	**$6,178,793**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2018 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$402,175	$0	$19,294	$21,629	$0	$0	$11,673	$52,596
215 Appalachian Power Co - Generation	18	0	3	1	0	0	1	5
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$402,193**	**$0**	**$19,297**	**$21,630**	**$0**	**$0**	**$11,674**	**$52,601**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$402,193**	**$0**	**$19,297**	**$21,630**	**$0**	**$0**	**$11,674**	**$52,601**
211 AEP Texas Central Company - Distribution	$1,962,432	$0	$5,101	$103,517	$0	$0	$56,959	$165,577
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	1	0	0	0	1
AEP Texas Central Co.	**$1,962,432**	**$0**	**$5,101**	**$103,518**	**$0**	**$0**	**$56,959**	**$165,578**
170 Indiana Michigan Power Co - Distribution	$98,249	$0	$10,349	$5,815	$0	$0	$2,852	$19,016
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	0	0	0
190 Indiana Michigan Power Co - Nuclear	231,925	0	16,893	13,414	0	2	6,732	37,041
120 Indiana Michigan Power Co - Transmission	89,311	0	0	4,688	0	0	2,592	7,280
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$419,485**	**$0**	**$27,242**	**$23,918**	**$0**	**$2**	**$12,176**	**$63,338**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$419,485**	**$0**	**$27,242**	**$23,918**	**$0**	**$2**	**$12,176**	**$63,338**
110 Kentucky Power Co - Distribution	$1,264	$0	$130	$69	$0	$0	$37	$236
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,264**	**$0**	**$130**	**$69**	**$0**	**$0**	**$37**	**$236**
250 Ohio Power Co - Distribution	$98,653	$0	$14,366	$6,181	$0	$0	$2,863	$23,410
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$98,653**	**$0**	**$14,366**	**$6,181**	**$0**	**$0**	**$2,863**	**$23,410**
167 Public Service Co of Oklahoma - Distribution	$1,729,915	$0	$8,948	$91,794	$0	($1)	$50,210	$150,951
198 Public Service Co of Oklahoma - Generation	315,413	0	473	16,802	0	0	9,155	26,430
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$2,045,328**	**$0**	**$9,421**	**$108,597**	**$0**	**($1)**	**$59,365**	**$177,382**
159 Southwestern Electric Power Co - Distribution	$400,125	$0	$37,286	$23,014	$0	$0	$11,614	$71,914
168 Southwestern Electric Power Co - Generation	803,767	0	877	42,848	0	0	23,329	67,054
161 Southwestern Electric Power Co - Texas - Distribution	248	0	0	14	0	0	7	21
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	70,943	0	0	3,504	0	0	2,059	5,563
Southwestern Electric Power Co.	**$1,275,083**	**$0**	**$38,163**	**$69,380**	**$0**	**$0**	**$37,009**	**$144,552**
119 AEP Texas North Company - Distribution	705,037	0	0	36,887	0	0	20,463	57,350
166 AEP Texas North Company - Generation	529,307	0	0	27,972	0	0	15,363	43,335
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,234,344**	**$0**	**$0**	**$64,859**	**$0**	**$0**	**$35,826**	**$100,685**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$53,362,580	$0	$400,975	$2,847,446	$0	$158	$1,548,834	$4,797,413
American Electric Power Service Corp	**$53,362,580**	**$0**	**$400,975**	**$2,847,446**	**$0**	**$158**	**$1,548,834**	**$4,797,413**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,421,268	0	55,174	135,876	0	5	70,277	261,332
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	171,902	0	2,346	9,323	0	(2)	4,989	16,656
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,593,170**	**$0**	**$57,520**	**$145,199**	**$0**	**$3**	**$75,266**	**$277,988**
270 Cook Coal Terminal	$0	$0	$0	$62	$0	$0	$0	$62
AEP Generating Company	**$0**	**$0**	**$0**	**$62**	**$0**	**$0**	**$0**	**$62**
104 Cardinal Operating Company	$2,493	$0	$184	$135	$0	$0	$72	$391
181 Ohio Power Co - Generation	688,856	0	3,736	33,984	0	0	19,994	57,714
AEP Generation Resources - FERC	**$691,349**	**$0**	**$3,920**	**$34,119**	**$0**	**$0**	**$20,066**	**$58,105**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$691,349**	**$0**	**$3,920**	**$34,119**	**$0**	**$0**	**$20,066**	**$58,105**
Total	**$64,085,881**	**$0**	**$576,135**	**$3,424,978**	**$0**	**$162**	**$1,860,075**	**$5,861,350**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2019 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$386,467	$0	$20,028	$21,273	$0	$0	$10,273	$51,574
215 Appalachian Power Co - Generation	17	0	4	(0)	0	0	0	4
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$386,484**	**$0**	**$20,032**	**$21,273**	**$0**	**$0**	**$10,273**	**$51,578**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$386,484**	**$0**	**$20,032**	**$21,273**	**$0**	**$0**	**$10,273**	**$51,578**
211 AEP Texas Central Company - Distribution	$1,885,784	$0	$5,296	$101,037	$0	$0	$50,130	$156,463
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	1	0	0	0	1
AEP Texas Central Co.	**$1,885,784**	**$0**	**$5,296**	**$101,038**	**$0**	**$0**	**$50,130**	**$156,464**
170 Indiana Michigan Power Co - Distribution	$94,411	$0	$10,743	$5,702	$0	$0	$2,510	$18,955
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	0	0	0
190 Indiana Michigan Power Co - Nuclear	222,867	0	17,535	12,990	0	0	5,924	36,449
120 Indiana Michigan Power Co - Transmission	85,822	0	0	4,586	0	0	2,281	6,867
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$403,100**	**$0**	**$28,278**	**$23,277**	**$0**	**$0**	**$10,715**	**$62,270**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$403,100**	**$0**	**$28,278**	**$23,277**	**$0**	**$0**	**$10,715**	**$62,270**
110 Kentucky Power Co - Distribution	$1,214	$0	$135	$68	$0	$0	$32	$235
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,214**	**$0**	**$135**	**$68**	**$0**	**$0**	**$32**	**$235**
250 Ohio Power Co - Distribution	$94,799	$0	$14,912	$6,048	$0	$0	$2,520	$23,480
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$94,799**	**$0**	**$14,912**	**$6,048**	**$0**	**$0**	**$2,520**	**$23,480**
167 Public Service Co of Oklahoma - Distribution	$1,662,349	$0	$9,289	$90,244	$0	$0	$44,190	$143,723
198 Public Service Co of Oklahoma - Generation	303,094	0	491	16,404	0	0	8,057	24,952
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$1,965,443**	**$0**	**$9,780**	**$106,648**	**$0**	**$0**	**$52,247**	**$168,675**
159 Southwestern Electric Power Co - Distribution	$384,497	$0	$38,705	$22,610	$0	$0	$10,221	$71,536
168 Southwestern Electric Power Co - Generation	772,373	0	910	41,856	0	0	20,532	63,298
161 Southwestern Electric Power Co - Texas - Distribution	238	0	0	13	0	0	6	19
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	68,172	0	0	3,393	0	0	1,812	5,205
Southwestern Electric Power Co.	**$1,225,280**	**$0**	**$39,615**	**$67,872**	**$0**	**$0**	**$32,571**	**$140,058**
119 AEP Texas North Company - Distribution	677,499	0	0	36,055	0	0	18,010	54,065
166 AEP Texas North Company - Generation	508,634	0	0	27,302	0	0	13,521	40,823
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,186,133**	**$0**	**$0**	**$63,357**	**$0**	**$0**	**$31,531**	**$94,888**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$51,278,355	$0	$416,232	$2,786,734	$0	$0	$1,363,131	$4,566,097
American Electric Power Service Corp	**$51,278,355**	**$0**	**$416,232**	**$2,786,734**	**$0**	**$0**	**$1,363,131**	**$4,566,097**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,326,698	0	57,273	132,875	0	0	61,851	251,999
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	165,188	0	2,435	9,149	0	0	4,391	15,975
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,491,886**	**$0**	**$59,708**	**$142,023**	**$0**	**$0**	**$66,242**	**$267,973**
270 Cook Coal Terminal	$0	$0	$0	$69	$0	$0	$0	$69
AEP Generating Company	**$0**	**$0**	**$0**	**$69**	**$0**	**$0**	**$0**	**$69**
104 Cardinal Operating Company	$2,396	$0	$191	$135	$0	$0	$64	$390
181 Ohio Power Co - Generation	661,951	0	3,878	33,433	0	0	17,597	54,908
AEP Generation Resources - FERC	**$664,347**	**$0**	**$4,069**	**$33,568**	**$0**	**$0**	**$17,661**	**$55,298**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$664,347**	**$0**	**$4,069**	**$33,568**	**$0**	**$0**	**$17,661**	**$55,298**
Total	**$61,582,825**	**$0**	**$598,057**	**$3,351,976**	**$0**	**$0**	**$1,637,053**	**$5,587,086**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2020 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$374,847	$0	$21,029	$19,853	$0	$0	$9,311	$50,193
215 Appalachian Power Co - Generation	16	0	4	0	0	0	0	4
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$374,863**	**$0**	**$21,033**	**$19,853**	**$0**	**$0**	**$9,311**	**$50,197**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$374,863**	**$0**	**$21,033**	**$19,853**	**$0**	**$0**	**$9,311**	**$50,197**
211 AEP Texas Central Company - Distribution	$1,829,084	$0	$5,560	$98,082	$0	$0	$45,432	$149,074
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	1	0	0	0	1
AEP Texas Central Co.	**$1,829,084**	**$0**	**$5,560**	**$98,082**	**$0**	**$0**	**$45,432**	**$149,074**
170 Indiana Michigan Power Co - Distribution	$91,573	$0	$11,280	$5,506	$0	$0	$2,275	$19,061
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	0	0	0
190 Indiana Michigan Power Co - Nuclear	216,166	0	18,412	12,328	0	0	5,369	36,109
120 Indiana Michigan Power Co - Transmission	83,242	0	0	4,451	0	0	2,068	6,519
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$390,981**	**$0**	**$29,692**	**$22,285**	**$0**	**$0**	**$9,712**	**$61,689**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$390,981**	**$0**	**$29,692**	**$22,285**	**$0**	**$0**	**$9,712**	**$61,689**
110 Kentucky Power Co - Distribution	$1,178	$0	$142	$66	$0	$0	$29	$237
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,178**	**$0**	**$142**	**$66**	**$0**	**$0**	**$29**	**$237**
250 Ohio Power Co - Distribution	$91,949	$0	$15,658	$5,923	$0	$0	$2,284	$23,865
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$91,949**	**$0**	**$15,658**	**$5,923**	**$0**	**$0**	**$2,284**	**$23,865**
167 Public Service Co of Oklahoma - Distribution	$1,612,367	$0	$9,753	$87,470	$0	$0	$40,049	$137,272
198 Public Service Co of Oklahoma - Generation	293,980	0	515	15,859	0	0	7,302	23,676
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$1,906,347**	**$0**	**$10,268**	**$103,329**	**$0**	**$0**	**$47,351**	**$160,948**
159 Southwestern Electric Power Co - Distribution	$372,936	$0	$40,640	$20,666	$0	$0	$9,263	$70,569
168 Southwestern Electric Power Co - Generation	749,150	0	955	40,525	0	0	18,608	60,088
161 Southwestern Electric Power Co - Texas - Distribution	231	0	0	13	0	0	6	19
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	66,122	0	0	3,497	0	0	1,642	5,139
Southwestern Electric Power Co.	**$1,188,439**	**$0**	**$41,595**	**$64,701**	**$0**	**$0**	**$29,519**	**$135,815**
119 AEP Texas North Company - Distribution	657,129	0	0	34,979	0	0	16,322	51,301
166 AEP Texas North Company - Generation	493,341	0	0	26,438	0	0	12,254	38,692
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,150,470**	**$0**	**$0**	**$61,417**	**$0**	**$0**	**$28,576**	**$89,993**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$49,736,564	$0	$437,044	$2,703,956	$0	$0	$1,235,404	$4,376,404
American Electric Power Service Corp	**$49,736,564**	**$0**	**$437,044**	**$2,703,956**	**$0**	**$0**	**$1,235,404**	**$4,376,404**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,256,741	0	60,137	129,203	0	0	56,055	245,395
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	160,222	0	2,557	8,863	0	0	3,980	15,400
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,416,963**	**$0**	**$62,694**	**$138,066**	**$0**	**$0**	**$60,035**	**$260,795**
270 Cook Coal Terminal	$0	$0	$0	$47	$0	$0	$0	$47
AEP Generating Company	**$0**	**$0**	**$0**	**$47**	**$0**	**$0**	**$0**	**$47**
104 Cardinal Operating Company	$2,324	$0	$201	$134	$0	$0	$58	$393
181 Ohio Power Co - Generation	642,048	0	4,072	32,059	0	0	15,948	52,079
AEP Generation Resources - FERC	**$644,372**	**$0**	**$4,273**	**$32,193**	**$0**	**$0**	**$16,006**	**$52,472**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$644,372**	**$0**	**$4,273**	**$32,193**	**$0**	**$0**	**$16,006**	**$52,472**
Total	**$59,731,210**	**$0**	**$627,959**	**$3,249,919**	**$0**	**$0**	**$1,483,659**	**$5,361,537**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2021 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$362,971	$0	$22,081	$19,403	$0	$0	$8,452	$49,936
215 Appalachian Power Co - Generation	16	0	4	1	0	0	0	5
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$362,987**	**$0**	**$22,085**	**$19,404**	**$0**	**$0**	**$8,452**	**$49,941**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$362,987**	**$0**	**$22,085**	**$19,404**	**$0**	**$0**	**$8,452**	**$49,941**
211 AEP Texas Central Company - Distribution	$1,771,132	$0	$5,838	$94,939	$0	$0	$41,240	$142,017
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	1	0	0	0	1
AEP Texas Central Co.	**$1,771,132**	**$0**	**$5,838**	**$94,940**	**$0**	**$0**	**$41,240**	**$142,018**
170 Indiana Michigan Power Co - Distribution	$88,671	$0	$11,844	$5,270	$0	$0	$2,065	$19,179
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	0	0	0
190 Indiana Michigan Power Co - Nuclear	209,317	0	19,333	12,194	0	0	4,874	36,401
120 Indiana Michigan Power Co - Transmission	80,605	0	0	4,313	0	0	1,877	6,190
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$378,593**	**$0**	**$31,177**	**$21,777**	**$0**	**$0**	**$8,816**	**$61,770**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$378,593**	**$0**	**$31,177**	**$21,777**	**$0**	**$0**	**$8,816**	**$61,770**
110 Kentucky Power Co - Distribution	$1,141	$0	$149	$49	$0	$0	$27	$225
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,141**	**$0**	**$149**	**$49**	**$0**	**$0**	**$27**	**$225**
250 Ohio Power Co - Distribution	$89,036	$0	$16,441	$5,795	$0	$0	$2,073	$24,309
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$89,036**	**$0**	**$16,441**	**$5,795**	**$0**	**$0**	**$2,073**	**$24,309**
167 Public Service Co of Oklahoma - Distribution	$1,561,282	$0	$10,241	$84,551	$0	$0	$36,354	$131,146
198 Public Service Co of Oklahoma - Generation	284,666	0	541	15,364	0	0	6,628	22,533
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$1,845,948**	**$0**	**$10,782**	**$99,915**	**$0**	**$0**	**$42,982**	**$153,679**
159 Southwestern Electric Power Co - Distribution	$361,120	$0	$42,672	$20,494	$0	$0	$8,408	$71,574
168 Southwestern Electric Power Co - Generation	725,415	0	1,003	39,169	0	0	16,891	57,063
161 Southwestern Electric Power Co - Texas - Distribution	224	0	0	13	0	0	5	18
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	64,027	0	0	3,618	0	0	1,491	5,109
Southwestern Electric Power Co.	**$1,150,786**	**$0**	**$43,675**	**$63,293**	**$0**	**$0**	**$26,795**	**$133,763**
119 AEP Texas North Company - Distribution	636,309	0	0	33,895	0	0	14,816	48,711
166 AEP Texas North Company - Generation	477,710	0	0	25,563	0	0	11,123	36,686
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,114,019**	**$0**	**$0**	**$59,458**	**$0**	**$0**	**$25,939**	**$85,397**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$48,160,757	$0	$458,896	$2,614,664	$0	$0	$1,121,397	$4,194,957
American Electric Power Service Corp	**$48,160,757**	**$0**	**$458,896**	**$2,614,664**	**$0**	**$0**	**$1,121,397**	**$4,194,957**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,185,241	0	63,144	124,628	0	0	50,882	238,654
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	155,145	0	2,685	8,344	0	0	3,612	14,641
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,340,386**	**$0**	**$65,829**	**$132,972**	**$0**	**$0**	**$54,494**	**$253,295**
270 Cook Coal Terminal	$0	$0	$0	$86	$0	$0	$0	$86
AEP Generating Company	**$0**	**$0**	**$0**	**$86**	**$0**	**$0**	**$0**	**$86**
104 Cardinal Operating Company	$2,250	$0	$211	$126	$0	$0	$52	$389
181 Ohio Power Co - Generation	621,706	0	4,276	30,843	0	0	14,476	49,595
AEP Generation Resources - FERC	**$623,956**	**$0**	**$4,487**	**$30,970**	**$0**	**$0**	**$14,528**	**$49,985**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$623,956**	**$0**	**$4,487**	**$30,970**	**$0**	**$0**	**$14,528**	**$49,985**
Total	**$57,838,741**	**$0**	**$659,359**	**$3,143,323**	**$0**	**$0**	**$1,346,743**	**$5,149,425**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2022 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$350,296	$0	$23,185	$19,139	$0	$0	$7,691	$50,015
215 Appalachian Power Co - Generation	15	0	4	1	0	0	0	5
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$350,311**	**$0**	**$23,189**	**$19,140**	**$0**	**$0**	**$7,691**	**$50,020**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$350,311**	**$0**	**$23,189**	**$19,140**	**$0**	**$0**	**$7,691**	**$50,020**
211 AEP Texas Central Company - Distribution	$1,709,286	$0	$6,130	$91,747	$0	$0	$37,526	$135,403
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	1	0	0	0	1
AEP Texas Central Co.	**$1,709,286**	**$0**	**$6,130**	**$91,748**	**$0**	**$0**	**$37,526**	**$135,404**
170 Indiana Michigan Power Co - Distribution	$85,575	$0	$12,436	$5,111	$0	$0	$1,879	$19,426
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	0	0	0
190 Indiana Michigan Power Co - Nuclear	202,008	0	20,299	11,991	0	0	4,435	36,725
120 Indiana Michigan Power Co - Transmission	77,790	0	0	4,167	0	0	1,708	5,875
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$365,373**	**$0**	**$32,735**	**$21,268**	**$0**	**$0**	**$8,022**	**$62,025**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$365,373**	**$0**	**$32,735**	**$21,268**	**$0**	**$0**	**$8,022**	**$62,025**
110 Kentucky Power Co - Distribution	$1,101	$0	$156	$66	$0	$0	$24	$246
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,101**	**$0**	**$156**	**$66**	**$0**	**$0**	**$24**	**$246**
250 Ohio Power Co - Distribution	$85,927	$0	$17,263	$5,604	$0	$0	$1,886	$24,753
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$85,927**	**$0**	**$17,263**	**$5,604**	**$0**	**$0**	**$1,886**	**$24,753**
167 Public Service Co of Oklahoma - Distribution	$1,506,763	$0	$10,753	$81,332	$0	$0	$33,080	$125,165
198 Public Service Co of Oklahoma - Generation	274,726	0	568	14,802	0	0	6,031	21,401
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$1,781,489**	**$0**	**$11,321**	**$96,133**	**$0**	**$0**	**$39,111**	**$146,565**
159 Southwestern Electric Power Co - Distribution	$348,510	$0	$44,805	$20,228	$0	$0	$7,651	$72,684
168 Southwestern Electric Power Co - Generation	700,084	0	1,053	37,729	0	0	15,370	54,152
161 Southwestern Electric Power Co - Texas - Distribution	216	0	0	12	0	0	5	17
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	61,791	0	0	3,491	0	0	1,357	4,848
Southwestern Electric Power Co.	**$1,110,601**	**$0**	**$45,858**	**$61,461**	**$0**	**$0**	**$24,383**	**$131,702**
119 AEP Texas North Company - Distribution	614,090	0	0	32,752	0	0	13,482	46,234
166 AEP Texas North Company - Generation	461,029	0	0	24,637	0	0	10,122	34,759
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,075,119**	**$0**	**$0**	**$57,389**	**$0**	**$0**	**$23,604**	**$80,993**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$46,479,024	$0	$481,841	$2,530,328	$0	$0	$1,020,417	$4,032,586
American Electric Power Service Corp	**$46,479,024**	**$0**	**$481,841**	**$2,530,328**	**$0**	**$0**	**$1,020,417**	**$4,032,586**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,108,934	0	66,301	120,587	0	0	46,300	233,188
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	149,728	0	2,819	8,441	0	0	3,287	14,547
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,258,662**	**$0**	**$69,120**	**$129,027**	**$0**	**$0**	**$49,587**	**$247,734**
270 Cook Coal Terminal	$0	$0	$0	$97	$0	$0	$0	$97
AEP Generating Company	**$0**	**$0**	**$0**	**$97**	**$0**	**$0**	**$0**	**$97**
104 Cardinal Operating Company	$2,172	$0	$222	$128	$0	$0	$48	$398
181 Ohio Power Co - Generation	599,997	0	4,490	30,142	0	0	13,173	47,805
AEP Generation Resources - FERC	**$602,169**	**$0**	**$4,712**	**$30,270**	**$0**	**$0**	**$13,221**	**$48,203**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$602,169**	**$0**	**$4,712**	**$30,270**	**$0**	**$0**	**$13,221**	**$48,203**
Total	**$55,819,062**	**$0**	**$692,325**	**$3,042,531**	**$0**	**$0**	**$1,225,472**	**$4,960,328**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2023 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$339,783	$0	$24,344	$17,975	$0	$0	$6,987	$49,306
215 Appalachian Power Co - Generation	15	0	4	1	0	0	0	5
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$339,798**	**$0**	**$24,348**	**$17,976**	**$0**	**$0**	**$6,987**	**$49,311**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$339,798**	**$0**	**$24,348**	**$17,976**	**$0**	**$0**	**$6,987**	**$49,311**
211 AEP Texas Central Company - Distribution	$1,657,986	$0	$6,437	$89,084	$0	$0	$34,094	$129,615
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	1	0	0	0	1
AEP Texas Central Co.	**$1,657,986**	**$0**	**$6,437**	**$89,085**	**$0**	**$0**	**$34,094**	**$129,616**
170 Indiana Michigan Power Co - Distribution	$83,007	$0	$13,058	$4,987	$0	$0	$1,707	$19,752
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	0	0	0
190 Indiana Michigan Power Co - Nuclear	195,945	0	21,314	11,660	0	0	4,029	37,003
120 Indiana Michigan Power Co - Transmission	75,455	0	0	4,048	0	0	1,552	5,600
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$354,407**	**$0**	**$34,372**	**$20,694**	**$0**	**$0**	**$7,288**	**$62,354**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$354,407**	**$0**	**$34,372**	**$20,694**	**$0**	**$0**	**$7,288**	**$62,354**
110 Kentucky Power Co - Distribution	$1,068	$0	$164	$64	$0	$0	$22	$250
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,068**	**$0**	**$164**	**$64**	**$0**	**$0**	**$22**	**$250**
250 Ohio Power Co - Distribution	$83,348	$0	$18,126	$5,466	$0	$0	$1,714	$25,306
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$83,348**	**$0**	**$18,126**	**$5,466**	**$0**	**$0**	**$1,714**	**$25,306**
167 Public Service Co of Oklahoma - Distribution	$1,461,542	$0	$11,291	$78,789	$0	$0	$30,055	$120,135
198 Public Service Co of Oklahoma - Generation	266,481	0	597	14,338	0	0	5,480	20,415
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$1,728,023**	**$0**	**$11,888**	**$93,127**	**$0**	**$0**	**$35,535**	**$140,550**
159 Southwestern Electric Power Co - Distribution	$338,051	$0	$47,046	$18,633	$0	$0	$6,952	$72,631
168 Southwestern Electric Power Co - Generation	679,073	0	1,106	36,520	0	0	13,964	51,590
161 Southwestern Electric Power Co - Texas - Distribution	209	0	0	12	0	0	4	16
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	59,937	0	0	3,386	0	0	1,233	4,619
Southwestern Electric Power Co.	**$1,077,270**	**$0**	**$48,152**	**$58,551**	**$0**	**$0**	**$22,153**	**$128,856**
119 AEP Texas North Company - Distribution	595,659	0	0	31,843	0	0	12,249	44,092
166 AEP Texas North Company - Generation	447,192	0	0	23,880	0	0	9,196	33,076
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,042,851**	**$0**	**$0**	**$55,723**	**$0**	**$0**	**$21,445**	**$77,168**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$45,084,077	$0	$505,933	$2,459,010	$0	$0	$927,089	$3,892,032
American Electric Power Service Corp	**$45,084,077**	**$0**	**$505,933**	**$2,459,010**	**$0**	**$0**	**$927,089**	**$3,892,032**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	2,045,640	0	69,616	116,933	0	0	42,066	228,615
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	145,234	0	2,960	8,197	0	0	2,987	14,144
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,190,874**	**$0**	**$72,576**	**$125,129**	**$0**	**$0**	**$45,053**	**$242,758**
270 Cook Coal Terminal	$0	$0	$0	$139	$0	$0	$0	$139
AEP Generating Company	**$0**	**$0**	**$0**	**$139**	**$0**	**$0**	**$0**	**$139**
104 Cardinal Operating Company	$2,107	$0	$233	$129	$0	$0	$43	$405
181 Ohio Power Co - Generation	581,989	0	4,714	29,178	0	0	11,968	45,860
AEP Generation Resources - FERC	**$584,096**	**$0**	**$4,947**	**$29,307**	**$0**	**$0**	**$12,011**	**$46,265**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$584,096**	**$0**	**$4,947**	**$29,307**	**$0**	**$0**	**$12,011**	**$46,265**
Total	**$54,143,798**	**$0**	**$726,943**	**$2,954,272**	**$0**	**$0**	**$1,113,391**	**$4,794,606**

AMERICAN ELECTRIC POWER
NONQUALIFIED RETIREMENT PLAN
ESTIMATED 2024 NET PERIODIC PENSION COST

Location	*Projected Benefit Obligation*	*Market-Related Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortization of Prior Service Cost*	*Amortization of Gain/Loss*	*Net Periodic Pension Cost*
140 Appalachian Power Co - Distribution	$329,935	$0	$25,561	$18,397	$0	$0	$6,351	$50,309
215 Appalachian Power Co - Generation	14	0	4	1	0	0	0	5
150 Appalachian Power Co - Transmission	0	0	0	0	0	0	0	0
Appalachian Power Co. - FERC	**$329,949**	**$0**	**$25,565**	**$18,398**	**$0**	**$0**	**$6,351**	**$50,314**
225 Cedar Coal Co	0	0	0	0	0	0	0	0
Appalachian Power Co. - SEC	**$329,949**	**$0**	**$25,565**	**$18,398**	**$0**	**$0**	**$6,351**	**$50,314**
211 AEP Texas Central Company - Distribution	$1,609,933	$0	$6,759	$86,619	$0	$0	$30,988	$124,366
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	0	0	0	1	0	0	0	1
AEP Texas Central Co.	**$1,609,933**	**$0**	**$6,759**	**$86,620**	**$0**	**$0**	**$30,988**	**$124,367**
170 Indiana Michigan Power Co - Distribution	$80,601	$0	$13,711	$4,343	$0	$0	$1,551	$19,605
132 Indiana Michigan Power Co - Generation	0	0	0	0	0	0	0	0
190 Indiana Michigan Power Co - Nuclear	190,266	0	22,380	11,242	0	0	3,662	37,284
120 Indiana Michigan Power Co - Transmission	73,268	0	0	3,938	0	0	1,410	5,348
280 Ind Mich River Transp Lakin	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - FERC	**$344,135**	**$0**	**$36,091**	**$19,523**	**$0**	**$0**	**$6,623**	**$62,237**
202 Price River Coal	0	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**$344,135**	**$0**	**$36,091**	**$19,523**	**$0**	**$0**	**$6,623**	**$62,237**
110 Kentucky Power Co - Distribution	$1,037	$0	$172	$63	$0	$0	$20	$255
117 Kentucky Power Co - Generation	0	0	0	0	0	0	0	0
180 Kentucky Power Co - Transmission	0	0	0	0	0	0	0	0
600 Kentucky Power Co. - Kammer Actives	0	0	0	0	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	0	0	0	0	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	0	0	0	0	0	0	0
Kentucky Power Co.	**$1,037**	**$0**	**$172**	**$63**	**$0**	**$0**	**$20**	**$255**
250 Ohio Power Co - Distribution	$80,932	$0	$19,032	$5,399	$0	$0	$1,558	$25,989
160 Ohio Power Co - Transmission	0	0	0	0	0	0	0	0
Ohio Power Co.	**$80,932**	**$0**	**$19,032**	**$5,399**	**$0**	**$0**	**$1,558**	**$25,989**
167 Public Service Co of Oklahoma - Distribution	$1,419,182	$0	$11,855	$76,866	$0	$0	$27,317	$116,038
198 Public Service Co of Oklahoma - Generation	258,757	0	626	13,908	0	0	4,981	19,515
114 Public Service Co of Oklahoma - Transmission	0	0	0	0	0	0	0	0
Public Service Co. of Oklahoma	**$1,677,939**	**$0**	**$12,481**	**$90,774**	**$0**	**$0**	**$32,298**	**$135,553**
159 Southwestern Electric Power Co - Distribution	$328,253	$0	$49,398	$19,334	$0	$0	$6,318	$75,050
168 Southwestern Electric Power Co - Generation	659,392	0	1,161	35,437	0	0	12,692	49,290
161 Southwestern Electric Power Co - Texas - Distribution	203	0	0	11	0	0	4	15
111 Southwestern Electric Power Co - Texas - Transmission	0	0	0	0	0	0	0	0
194 Southwestern Electric Power Co - Transmission	58,200	0	0	3,288	0	0	1,120	4,408
Southwestern Electric Power Co.	**$1,046,048**	**$0**	**$50,559**	**$58,071**	**$0**	**$0**	**$20,134**	**$128,764**
119 AEP Texas North Company - Distribution	578,396	0	0	31,015	0	0	11,133	42,148
166 AEP Texas North Company - Generation	434,232	0	0	23,183	0	0	8,358	31,541
192 AEP Texas North Company - Transmission	0	0	0	0	0	0	0	0
AEP Texas North Co.	**$1,012,628**	**$0**	**$0**	**$54,198**	**$0**	**$0**	**$19,491**	**$73,689**
230 Kingsport Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
260 Kingsport Power Co - Transmission	0	0	0	0	0	0	0	0
Kingsport Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
210 Wheeling Power Co - Distribution	$0	$0	$0	$0	$0	$0	$0	$0
200 Wheeling Power Co - Transmission	0	0	0	0	0	0	0	0
Wheeling Power Co.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
103 American Electric Power Service Corporation	$43,777,417	$0	$531,229	$2,386,398	$0	$0	$842,636	$3,760,263
American Electric Power Service Corp	**$43,777,417**	**$0**	**$531,229**	**$2,386,398**	**$0**	**$0**	**$842,636**	**$3,760,263**
143 AEP Pro Serv, Inc.	$0	$0	$0	$0	$0	$0	$0	$0
171 CSW Energy, Inc.	1,986,351	0	73,097	112,230	0	0	38,234	223,561
293 Elmwood	0	0	0	0	0	0	0	0
292 AEP River Operations LLC	141,025	0	3,108	7,969	0	0	2,714	13,791
189 Central Coal Company	0	0	0	0	0	0	0	0
Miscellaneous	**$2,127,376**	**$0**	**$76,205**	**$120,200**	**$0**	**$0**	**$40,948**	**$237,353**
270 Cook Coal Terminal	$0	$0	$0	$151	$0	$0	$0	$151
AEP Generating Company	**$0**	**$0**	**$0**	**$151**	**$0**	**$0**	**$0**	**$151**
104 Cardinal Operating Company	$2,046	$0	$244	$126	$0	$0	$39	$409
181 Ohio Power Co - Generation	565,122	0	4,950	28,279	0	0	10,878	44,107
AEP Generation Resources - FERC	**$567,168**	**$0**	**$5,194**	**$28,405**	**$0**	**$0**	**$10,917**	**$44,516**
290 Conesville Coal Preparation Company	0	0	0	0	0	0	0	0
AEP Generation Resources - SEC	**$567,168**	**$0**	**$5,194**	**$28,405**	**$0**	**$0**	**$10,917**	**$44,516**
Total	**$52,574,562**	**$0**	**$763,287**	**$2,868,199**	**$0**	**$0**	**$1,011,964**	**$4,643,450**

American Electric Power

Non-UMWA Postretirement Health Care Plan

Actuarial Valuation Report
Postretirement Welfare Cost for Fiscal Year Ending December 31, 2014 under U.S. GAAP

Employer Contributions for Plan Year Beginning January 1, 2014

April 2014

TOWERS WATSON

Table of Contents

This page is intentionally blank

Purpose and actuarial statement

Purposes of valuation

American Electric Power retained Towers Watson Delaware Inc. ("Towers Watson"), to perform an actuarial valuation of its postretirement welfare programs for the purpose of determining the following:

(1) The value of benefit obligations as of January 1, 2014, and American Electric Power's postretirement welfare cost for fiscal year ending December 31, 2014, in accordance with FASB Accounting Standards Codification Topic 715 (ASC 715-60). It is anticipated that a separate report will be prepared for year-end financial reporting and disclosure purposes.

(2) Plan reporting information in accordance with FASB Accounting Standards Codification Topic 965 (ASC 965).

(3) Expected contributions under the plan sponsor's funding policy for the 2014 plan year.

(4) The estimated maximum tax-deductible contribution for the tax year in which the 2014 plan year ends as allowed by the Internal Revenue Code. The maximum tax-deductible contribution should be finalized in consultation with American Electric Power's tax advisor.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices.

Reliances

In preparing the results presented in this report, we have relied upon information regarding plan provisions, participants, claims data, contributions and assets (if any) provided by American Electric Power and other persons or organizations designated by American Electric Power. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations. We have relied on all the information provided as complete and accurate. The results presented in this report are dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data and information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies, as corrected by American Electric Power, may produce materially different results that could require that a revised report be issued.

Assumptions and methods under the Internal Revenue Code for contribution limit purposes

The actuarial assumptions and methods employed in the development of the contribution limits have been selected by the plan sponsor, with the concurrence of Towers Watson. The Internal Revenue Code requires the use of reasonable assumptions (taking into account the experience of the plan and reasonable expectations) which, in combination, offer the actuary's best estimate of anticipated experience under the plan. We believe that the assumptions used in our valuation are reasonable and appropriate for the purposes for which they have been used.

Assumptions and methods under ASC 715-60

The actuarial assumptions and methods employed in the development of the postretirement welfare cost have been selected by the plan sponsor with the concurrence of Towers Watson, except for the expected rate of return on plan assets selected for fiscal 2014. Evaluation of the expected rate of return assumption was outside the scope of Towers Watson's assignment and would have required substantial additional work that we were not engaged to perform. ASC 715-60 requires that each significant assumption "individually represent the best estimate of a particular future event".

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for deferred taxes. Any deferred tax effects in AOCI should be determined in consultation with American Electric Power's tax advisors and auditors.

Effects of Health Care Legislation

In March 2010, the Patient Protection and Affordable Care Act (PPACA) and Health Care and Education Reconciliation Act (HCERA) were enacted. The key aspects of the Acts affecting American Electric Power's benefit obligation and cost of providing retiree medical benefits are:

- Availability of subsidies from the Early Retiree Reinsurance Program (ERRP)
- Preventive care benefits covered at 100% beginning in 2011
- Mandatory coverage for adult children until age 26 beginning in 2011
- Loss of the tax free status of the Retiree Drug Subsidy (RDS) beginning in 2013
- Excise ("Cadillac") tax on high-cost plans beginning in 2018
- Elimination of lifetime maximums beginning in 2011
- Transitional reinsurance fees beginning in 2014

All subsequent measurements for tax purposes reflect the new law.

This valuation reflects our understanding of the relevant provisions of PPACA and HCERA. The IRS and HHS have yet to issue final guidance with respect to many aspects of this law. It is possible that future guidance may conflict with our understanding of these laws based on currently available guidance and could therefore affect the results shown in this report.

Nature of actuarial calculations

The results shown in this report have been developed based on actuarial assumptions that, to the extent evaluated or selected by Towers Watson, we consider reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

The results shown in this report are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with certainty. The effects of certain plan provisions may be approximated, or determined to be insignificant and therefore not valued. Assumptions may be made, in consultation with American Electric Power, about participant data or other factors. Reasonable efforts were made in preparing this valuation to confirm that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and are not excluded or included inappropriately. The numbers shown in this report are not rounded. This is for convenience only and should not imply precision; by their nature, actuarial calculations are not precise.

If overall future plan experience produces higher benefit payments or lower investment returns than assumed, the relative level of plan costs or contribution requirements reported in this valuation will likely increase in future valuations (and vice versa). Future actuarial measurements may differ significantly from the current measurements presented in this report due to many factors, including: plan experience differing from that anticipated by the economic or demographic assumptions; increases or reductions expected as part of the natural operation of the methodology used for the measurements (such as the end of an amortization period); and changes in plan provisions or applicable law. It is beyond the scope of this valuation to analyze the potential range of future postretirement welfare contributions, but we can do so upon request.

See Basis for Valuation in Section 1 below for a discussion of any material events that have occurred after the valuation date that are not reflected in this valuation.

Limitations on use

This report is provided subject to the terms set out herein and in our master consulting services agreement dated July 29, 2004, and any accompanying or referenced terms and conditions.

The information contained in this report was prepared for the internal use of American Electric Power and its auditors in connection with our actuarial valuation of the postretirement welfare plan as described in Purposes of Valuation above. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard. American Electric Power may distribute this actuarial valuation report to the appropriate authorities who have the legal right to require American Electric Power to provide them this report, in which case American Electric Power will use best efforts to notify Towers Watson in advance of this distribution, and will include the non-reliance notice included at the end of this report. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited without Towers Watson's prior written consent. In the absence of such consent and an express assumption of responsibility, we accept no responsibility whatsoever for any consequences arising from any third party relying on this report or any advice relating to its contents. There are no intended third-party beneficiaries of this report or the work underlying it.

Professional Qualifications

The undersigned consulting actuaries are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to postretirement welfare plans. Our objectivity is not impaired by any relationship between American Electric Power and our employer, Towers Watson Delaware Inc.

Martin P. Franzinger

Martin P. Franzinger, ASA, MAAA
Consulting Actuary

Chad Greenwalt

Chad M. Greenwalt, FSA, EA
Consulting Actuary

Joseph A. Perko, FSA, EA, MAAA
Senior Consultant

Towers Watson Delaware Inc.

April 2014

Section 1: Summary of key results

Benefit cost, assets & obligations

All monetary amounts shown in US Dollars

Fiscal Year Beginning		January 1, 2014	January 1, 2013
Benefit Cost/ (Income)	Net Periodic Postretirement Benefit Cost/(Income)	($84,466,169)	($27,206,006)
Measurement Date		**January 1, 2014**	**January 1, 2013**
Plan Assets	Fair Value of Assets (FVA)	1,678,022,909	1,568,431,705
Benefit Obligations	Accumulated Postretirement Benefit Obligation (APBO)	1,361,155,680	1,702,312,240
Funded Status	Funded Status	316,867,229	(133,880,535)
Accumulated Other Comprehensive (Income)/Loss	Net Transition Obligation/(Asset)	0	0
	Net Prior Service Cost/(Credit)	(692,534,083)	(761,590,889)
	Net Loss/(Gain)	393,952,797	895,454,738
	Total Accumulated Other Comprehensive (Income)/Loss	(298,581,286)	133,863,849
Assumptions[1]	Discount Rate	4.70%	3.95%
	Expected Long-term Return on Plan Assets	6.75%	7.00%
	Rate of Compensation/Salary Increase	Rates vary by age from 3.5% to 11.5%	Rates vary by age from 3.5% to 11.5%
	Current Health Care Cost Trend Rate	6.50%	6.75%
	Ultimate Health Care Cost Trend Rate	5.00%	5.00%
	Year of Ultimate Trend Rate	2020	2020
Participant Data	Census Date	January 1, 2014	January 1, 2013
Plan reporting (ASC 965) for Plan Year Beginning		**January 1, 2014**	**January 1, 2013**
	Present value of accumulated benefits	1,361,705,751	1,702,879,344
	Market value of assets	1,678,022,909	1,568,431,705
	Plan reporting discount rate	4.70%	3.95%
Employer Contributions (net of Medicare subsidy)		**Plan Year 2014**	**Plan Year 2013**
Cash Flow	Funding Policy contributions	0	0
	Maximum Tax Deductible contributions	86,031,463 (est.)	0
	Actual contributions	N/A	N/A
	Expected benefit payments and expenses, net of participant contributions	102,698,063	94,150,747

Employer Contributions

Employer contributions are the amounts paid by American Electric Power to provide for postretirement benefits, net of participant contributions and Medicare subsidy. Most participants receiving benefits are required to contribute toward the cost of the plan.

[1] Rates are expressed on an annual basis where applicable.

American Electric Power's funding policy is to contribute an amount equal to the postretirement welfare cost plus retiree drug subsidy payments received (the sum of which can be no less than zero). American Electric Power maximizes its contribution to the 401(h) account and contributes the remainder to the various VEBAs. American Electric Power may deviate from this policy, as permitted by its terms, based on cash, tax or other considerations.

Postretirement welfare cost and funded position

The cost of the postretirement welfare plan is determined in accordance with generally accepted accounting principles in the U.S. ("U.S. GAAP"). The Fiscal 2014 postretirement welfare benefit cost for the plan is $(84,466,169). Under U.S. GAAP, the funded position (fair value of plan assets less the projected benefit obligation, or "APBO") of each postretirement welfare plan at the plan sponsor's fiscal year-end (measurement date) is required to be reported as a liability. The APBO is the actuarial present value of benefits attributed to service rendered prior to the measurement date, taking into consideration expected future pay increases for pay-related plans. The plan's (underfunded) APBO as of January 1, 2013 was $316,867,229 based on the fair value of plan assets of $1,678,022,909 and the APBO of $1,361,155,680.

Fiscal year-end financial reporting information and disclosures are prepared before detailed participant data and full valuation results are available. Therefore, the postretirement benefit asset (liability) at January 1, 2014 was derived from a roll forward of the January 1, 2013 valuation results, adjusted for the year-end discount rate and asset values, as well as significant changes in plan provisions and participant population. The next fiscal year financial reporting information will be developed based on the results of the January 1, 2014 valuation, projected to the end of the year and similarly adjusted for the year-end discount rate and asset values, as well as significant changes in plan provisions and participant population.

Change in postretirement welfare cost and funded position

The postretirement welfare cost decreased from $(27,206,006) in fiscal 2013 to $(84,466,169) in fiscal 2014 and the funded position increased from $(133,880,535) on January 1, 2013 to $316,867,229 on January 1, 2014, as set forth below:

All monetary amounts shown in US Dollars

	Postretirement Welfare Cost
Prior year	(27,206,006)
Change due to:	
► Expected based on prior valuation and contributions during prior year	(1,570,214)
► Unexpected noninvestment experience	1,235,151
► Unexpected investment experience	(15,023,495)
► Assumption changes	(41,901,605)
► Changes in substantive plan	0
► Changes due to Affordable Care Act	0
Current year	(84,466,169)

Significant reasons for these changes include the following:

- On average, per capita claims costs increased greater than expected, which increased the postretirement welfare cost.

All monetary amounts shown in US Dollars

	2014	2013
Medical (Overall Average)		
Under age 65		
▸ Aetna	9,425	9,066
▸ Lumenos	9,591	8,970
Age 65 and older (before Part D offsets)		
▸ COB	4,258	4,003
▸ MOB	3,217	2,948
▸ CSP	1,976	1,978
Medicare Part D Subsidy offsets		
▸ MOB/COB (EGWP)	(805)	(891)
▸ CSP (RDS)	(286)	(223)

See Appendix A for additional details on per capita claims costs assumptions including assumed claims costs by age and/or morbidity adjustments applied.

- The discount rate increased 75 basis points since the prior year which decreased the postretirement welfare cost.

- The expected return on the fair value of assets was decreased from 7.00% to 6.75% which increased the postretirement welfare cost.

- Actual asset returns during 2013 were more than the assumed rate of 7.00% which decreased the postretirement welfare cost.

- The assumption for the percentage of future retirees electing coverage decreased from 95% for all years to 95% in 2014 and 2015 with the rate decreasing by 5% annually beginning in 2016 to an ultimate rate of 75% in 2019, which decreased the postretirement welfare cost.

- The retiree medical persistency assumption was added stating that beginning in 2014. Non-capped retirees will drop coverage at a rate of 2% annually and Capped retirees will drop coverage at a rate of 4% annually which decreased the postretirement welfare cost.

Basis for valuation

Appendix A summarizes the assumptions and methods used in the valuation. Appendix B summarizes our understanding of the principal provisions of the plan being valued. The most recent plan change reflected in this valuation was effective on January 1, 2013.

Changes in Assumptions

- Per capita claims costs were updated to reflect more recent retiree claims experience.
- Discount rate was changed from 3.95% to 4.70%.
- Mortality was updated for an additional year of mortality improvements.
- The expected return on assets was decreased from 7.00% to 6.75% for postretirement welfare costs purposes. The expected return on assets used to calculate funding requirements was also reduced by 25 basis points for each funding vehicle.
- The assumption for the percentage of future retirees electing coverage decreased from 95% for all years to 95% in 2014 and 2015 with the rate decreasing by 5% annually beginning in 2016 to an ultimate rate of 75% in 2019.
- The retiree medical persistency assumption was added stating that beginning in 2014. Non-capped retirees will drop coverage at a rate of 2% annually and Capped retirees will drop coverage at a rate of 4% annually.

Changes in Methods

None.

Changes in Benefits Valued

None.

Section 2 : Actuarial exhibits

2.1 Balance sheet asset/(liability)

All monetary amounts shown in US Dollars

Measurement Date			January 1, 2014	January 1, 2013
A		**Development of Balance Sheet Asset/(Liability)**[1]		
	1	Accumulated postretirement benefit obligation (APBO)	1,361,155,680	1,702,312,240
	2	Fair value of assets (FVA)	1,678,022,909	1,568,431,705
	3	Net balance sheet asset/(liability)	316,867,229	(133,880,535)
B		**Current and Noncurrent Allocation**		
	1	Noncurrent assets	0	0
	2	Current liabilities	0	0
	3	Noncurrent liabilities	316,867,229	(133,880,535)
	4	Net balance sheet asset/(liability)	316,867,229	(133,880,535)
C		**Accumulated Other Comprehensive (Income)/Loss**		
	1	Net transition obligation/(asset)	0	0
	2	Net prior service cost/(credit)	(692,534,083)	(761,590,889)
	3	Net loss/(gain)	393,952,797	895,454,738
	4	Accumulated other comprehensive (income)/loss[2]	(298,581,286)	133,863,849
D		**Assumptions and Dates**		
	1	Discount rate	4.70%	3.95%
	2	Rate of compensation/salary increase	Rates vary by age from 3.5% to 11.5%	Rates vary by age from 3.5% to 11.5%
	3	Current health care cost trend rate	6.50%	6.75%
	4	Ultimate health care cost trend rate	5.00%	5.00%
	5	Year of ultimate trend rate	2020	2020
	6	Census date	January 1, 2014	January 1, 2013

[1] Whether the amounts in this table that differ from those disclosed at year-end must be disclosed in subsequent interim financial statements should be determined.

[2] Amount shown is pre-tax and should be adjusted by plan sponsor for tax effects.

2.2 Summary and comparison of postretirement benefit cost and cash flows

All monetary amounts shown in US Dollars

Fiscal Year Ending			December 31, 2014	December 31, 2013
A		**Total Postretirement Benefit Cost**		
	1	Employer service cost	12,916,313	21,325,637
	2	Interest cost	62,195,689	66,243,553
	3	Expected return on assets	(109,857,082)	(106,553,009)
	4	Subtotal	(34,745,080)	(18,983,819)
	5	Net prior service cost/(credit) amortization	(69,056,806)	(69,056,806)
	6	Net loss/(gain) amortization	19,335,717	60,834,619
	7	Transition obligation/(asset) amortization	0	0
	8	Amortization subtotal	(49,721,089)	(8,222,187)
	9	Net periodic postretirement benefit cost/(income)	(84,466,169)	(27,206,006)
B		**Assumptions**[1]		
	1	Discount rate	4.70 %	3.95 %
	2	Long-term rate of return on assets	6.75 %	7.00 %
	3	Rate of compensation/salary increase	Rates vary by age from 3.5% to 11.5%	Rates vary by age from 3.5% to 11.5%
	4	Current health care cost trend rate	6.50 %	6.75 %
	5	Ultimate health care cost trend rate	5.00 %	5.00 %
	6	Year ultimate trend rate is expected	2020	2020
C		**Census Date**	January 1, 2014	January 1, 2013
D		**Assets at Beginning of Year**		
	1	Fair market value	1,678,022,909	1,568,431,705
E		**Cash Flow**	**Expected**	**Actual**
	1	Employer contributions	0	0
	2	Plan participants' contributions	30,994,353	38,769,562
	3	Benefits paid from plan assets	133,772,859	134,972,370
	4	Expected Medicare subsidy on current year benefit payments	(80,443)	N/A

[1] These assumptions were used to calculate the Net Postretirement Benefit Cost/ (Income) as of the beginning of the year. Rates are expressed on an annual basis where applicable. For assumptions used for interim measurement periods, if any, refer to Appendix A.

2.3 Information for deferred tax calculations

The following information is provided for purposes of determining the deferred portion of the tax provision and the deferred tax asset associated with the postretirement welfare cost and obligation, respectively. This information reflects the tax-exempt status of the Retiree Drug Subsidy ("RDS") payment at the valuation date.

All monetary amounts shown in US Dollars

			Book Basis Net of Part D Subsidy	Tax Basis Net of Part D Subsidy after 2012
A	**Postretirement Welfare Cost**			
	1	Fiscal 2014	(84,466,169)	(100,327,313)
	2	Fiscal 2013	(27,206,006)	(45,021,502)
B	**Funded Position**			
	1	Overfunded (underfunded) APBO	316,867,229	316,867,229

2.4 Detailed results for postretirement welfare cost and funded position

All monetary amounts shown in US Dollars

Detailed results			January 1, 2014	January 1, 2013
A	**Service Cost**			
	1	Medical	10,209,364	17,844,928
	2	Life insurance	2,704,640	3,475,991
	3	Dental	2,309	4,718
	4	Total	12,916,313	21,325,637
B	**Accumulated Postretirement Benefit Obligation [APBO]**			
	1	Medical[1]:		
	a	Participants currently receiving benefits	744,543,186	920,847,291
	b	Fully eligible active participants	24,418,320	24,157,727
	c	Other participants	242,502,413	391,590,878
	d	Total	1,011,463,919	1,336,595,896
	2	Life insurance:		
	a	Participants currently receiving benefits	257,582,776	258,635,009
	b	Fully eligible active participants	7,452,219	5,716,564
	c	Other participants	66,267,434	79,722,542
	d	Total	331,302,429	344,074,115
	3	Dental:		
	a	Participants currently receiving benefits	17,893,482	20,798,974
	b	Fully eligible active participants	0	0
	c	Other participants	495,850	843,255
	d	Total	18,389,332	21,642,229
	4	All Benefits:		
	a	Participants currently receiving benefits	1,020,019,444	1,200,281,274
	b	Fully eligible active participants	31,870,539	29,874,291
	c	Other participants	309,265,697	472,156,675
	d	Total	1,361,155,680	1,702,312,240
C	**Assets**			
	1	Fair value [FV]	1,678,022,909	1,568,431,705
D	**Funded Position**			
	1	Overfunded (underfunded) APBO	316,867,229	(133,880,535)
	2	APBO funded percentage	123.3%	92.1%

[1] The Transitional Reinsurance Fee was allocated among the different segments of the medical liability in proportion to the total medical liability.

E	**Amounts in Accumulated Other Comprehensive Income**			
	1 Prior service cost (credit)		(692,534,083)	(761,590,889)
	2 Net actuarial loss (gain)		393,952,797	895,454,738
	3 Transition obligation (asset)		0	0
	4 Total		(298,581,286)	133,863,849
F	**Effect of Change in Health Care Cost Trend Rate**			
	1 One-percentage-point increase:			
		a Sum of service cost and interest cost	2,684,320	4,434,775
		b APBO	56,819,974	95,451,772
	2 One-percentage-point decrease:			
		a Sum of service cost and interest cost	(2,065,260)	(2,924,226)
		b APBO	(46,669,068)	(72,246,544)

2.5 ASC 965 (plan reporting) information (formerly SOP 92-6, as amended by SOP 01-2)

All monetary amounts shown in US Dollars

Summary of Present Value of Benefits		January 1, 2014	January 1, 2013
A	**Medical (ignoring Retiree Drug Subsidy)**		
1	Current retirees	745,093,257	921,414,395
2	Active participants fully eligible for participants	24,418,320	24,157,727
3	Other active participants	242,502,413	391,590,878
4	Total	1,012,013,990	1,337,163,000
B	**Life Insurance**		
1	Current retirees	257,582,776	258,635,009
2	Active participants fully eligible for participants	7,452,219	5,716,564
3	Other active participants	66,267,434	79,722,542
4	Total	331,302,429	344,074,115
C	**Dental**		
1	Current retirees	17,893,482	20,798,974
2	Active participants fully eligible for participants	0	0
3	Other active participants	495,850	843,255
4	Total	18,389,332	21,642,229
D	**Total (ignoring Retiree Drug Subsidy)**		
1	Current retirees	1,020,569,515	1,200,848,378
2	Active participants fully eligible for participants	31,870,539	29,874,291
3	Other active participants	309,265,697	472,156,675
4	Total	1,361,705,751	1,702,879,344

Actuarial assumptions and methods

The key actuarial assumptions used for plan reporting calculations are the same as those used to determine the postretirement welfare cost and are shown in the Actuarial Assumptions and Methods section, except that the Retiree Drug Subsidy (RDS) associated with Medicare Part D is not reflected. For the prior valuation, a discount rate of 3.95% was used. The same plan provisions shown in Appendix B were used to determine the present value of accumulated benefits.

Reconciliation of Present Value of Benefits		Fiscal 2013	Fiscal 2012
A	**Medical (ignoring Retiree Drug Subsidy)**		
1	Benefit obligation, beginning of year	1,337,163,000	1,765,617,401
2	Service cost	17,844,928	42,695,197
3	Interest cost	51,716,805	82,868,101
4	Participant contributions	29,543,748	29,426,161
5	Actuarial (gain)/loss	(302,373,040)	123,767,283
6	Plan amendments	0	(578,273,313)
7	Gross benefits paid	(121,881,451)	(128,937,830)
8	Benefit obligation, end of year	1,012,013,990	1,337,163,000
B	**Life Insurance**		
1	Benefit obligation, beginning of year	344,074,115	303,722,815
2	Service cost	3,475,991	2,917,895
3	Interest cost	13,476,642	14,287,347
4	Participant contributions	1,590,196	1,686,524
5	Actuarial (gain)/loss	(16,861,174)	33,305,895
6	Plan amendments	0	0
7	Gross benefits paid	(14,453,341)	(11,846,361)
8	Benefit obligation, end of year	331,302,429	344,074,115
C	**Dental**		
1	Benefit obligation, beginning of year	21,642,229	21,070,446
2	Service cost	4,718	5,434
3	Interest cost	803,562	857,492
4	Participant contributions	3,769,553	3,969,765
5	Actuarial (gain)/loss	(1,428,469)	1,856,905
6	Plan amendments	0	0
7	Gross benefits paid	(6,402,261)	(6,117,813)
8	Benefit obligation, end of year	18,389,332	21,642,229
D	**Total (ignoring Retiree Drug Subsidy)**		
1	Benefit obligation, beginning of year	1,702,879,344	2,090,410,662
2	Service cost	21,325,637	45,618,526
3	Interest cost	65,997,009	98,012,940
4	Participant contributions	34,903,497	35,082,450
5	Actuarial (gain)/loss	(320,662,683)	158,930,083
6	Plan amendments	0	(578,273,313)
7	Gross benefits paid	(142,737,053)	(146,902,004)
8	Benefit obligation, end of year	1,361,705,751	1,702,879,344

2.6 Basic results for employer contributions - VEBAs

All monetary amounts shown in US Dollars

All Postretirement VEBAs			Estimated December 31, 2014	December 31, 2013
A	**Qualified Asset Account Limits [QAAL]**		721,662,041	750,652,358
B	**Assets**			
	1	Market value	1,308,712,908	1,322,244,577
	2	Unrecognized investment losses (gains)	0	0
	3	Actuarial value [AV]	1,308,712,908	1,322,244,577
C	**Funded Position**			
	1	Unfunded account limits [QAAL – FV]	(587,050,867)	(571,592,219)
D	**Employer Contributions**			
	1	Maximum deductible available	84,581,378	77,026,026
	2	Qualified additions		
		a Prior years' carryover	0	0
		b Current year additions	0	0
		c Total deductions available [a + b]	0	0
	3	Other non-deductible current year additions	0	0
	4	Total additions [2.c + 3]	0	0
		a Life insurance VEBA	0	0
		b Union medical and dental VEBAs	0	0
		c Non-union medical and dental VEBAs	0	0

2.7 VEBA deduction limits

All monetary amounts shown in US Dollars

Life Insurance			2013	2012
A	**Qualified Asset Account Limit (QAAL)**			
	1	December 31 actuarial accrued liability	217,706,691	171,324,145
	2	Unrecognized liability	0	0
	3	QAAL	217,706,691	171,324,145
B	**Assets**			
	1	Market value as of December 31	140,680,665	140,292,810
	2	Unrecognized investment losses (gains)	0	0
	3	Actuarial value [AV]	140,680,665	140,292,810
C	**Funded position**			
	1	Unfunded account limit [QAAL - AV]	77,026,026	31,031,335
	2	Contributions received in trust, but not yet deducted		
		2009	0	0
		2010	0	0
		2011	0	0
		2012	0	0
		2013	0	N/A
		Total	0	0
D	**Employer deductions for contributions to VEBAs**			
	1	Maximum deduction available[1] [C.1 + Total of C.2]	77,026,026	31,031,335
	2	Qualified additions		
		a Prior years' carryover	0	0
		b Current year additions	0	0
		c Total deductions available [a + b]	0	0
	3	Other non-deductible current year additions	0	0
	4	Total additions [2.c + 3]	0	0

[1] Includes amounts not contributed.

TOWERS WATSON

All monetary amounts shown in US Dollars

Union Medical and Dental			2013	2012
A	**Qualified Asset Account Limit (QAAL)**			
	1	December 31 present value of projected benefits	212,964,386	253,933,697
	2	Unrecognized liability	0	0
	3	QAAL	212,964,386	253,933,697
B	**Assets**			
	1	Market value as of December 31	436,275,257	419,870,918
	2	Unrecognized investment losses (gains)	0	0
	3	Actuarial value [AV]	436,275,257	419,870,918
C	**Funded position**			
	1	Unfunded account limit [QAAL - AV]	(233,310,871)	(165,937,221)
	2	Contributions received in trust, but not yet deducted		
		2009	0	0
		2010	0	0
		2011	0	0
		2012	0	0
		2013	0	N/A
		Total	0	0
D	**Employer deductions for contributions to VEBAs**			
	1	Maximum deduction available[1] [C.1 + Total of C.2]	0	0
	2	Qualified additions		
		a Prior years' carryover	0	0
		b Current year additions	0	1,008,523
		c Total deductions available [a + b]	0	1,008,523
	3	Other non-deductible current year additions	0	0
	4	Total additions [2.c + 3]	0	1,008,523

[1] Includes amounts not contributed.

All monetary amounts shown in US Dollars

Non-union Medical and Dental			2013	2012
A	**Qualified Asset Account Limit (QAAL)**			
	1	December 31 present value of projected benefits	319,981,281	406,874,206
	2	Unrecognized liability	0	0
	3	QAAL	319,981,281	406,874,206
B	**Assets**			
	1	Market value as of December 31	745,288,655	706,535,443
	2	Unrecognized investment losses (gains)	0	0
	3	Actuarial value [AV]	745,288,655	706,535,443
C	**Funded position**			
	1	Unfunded account limit [QAAL - AV]	(425,307,374)	(299,661,237)
	2	Contributions received in trust, but not yet deducted		
		2008	0	0
		2009	105,440,603	105,440,603
		2010	73,467,453	73,467,453
		2011	38,701,148	38,701,148
		2012	68,292,490	68,292,490
		2013	0	N/A
		Total	285,901,694	285,901,694
D	**Employer deductions for contributions to VEBAs**			
	1	Maximum deduction available[1] [greater of C.1+C.2 and 0]	0	0
	2	Qualified additions		
		a Prior years' carryover	0	0
		b Current year additions	0	0
		c Total deductions available [a + b]	0	0
	3	Other non-deductible current year additions	0	68,292,400
	4	Total additions [2.c + 3]	0	68,292,400

[1] Includes amounts not contributed.

2.8 Cumulative nondeductible contributions

All monetary amounts shown in US Dollars

Non-union Retiree Medical and Dental VEBAs

	Contributions Made by December 31, 2013, but Not Deducted as of December 31, 2012	Deductible in 2013	Remaining Nondeductible Contributions as of December 31, 2013
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	105,440,603	0	105,440,603
2010	73,467,453	0	73,467,453
2011	38,701,148	0	38,701,148
2012	68,292,490	0	68,292,490
2013	0	0	0
Total	285,901,694	0	285,901,694

Retiree Life Insurance VEBAs

	Contributions Made by December 31, 2013, but Not Deducted as of December 31, 2012	Deductible in 2013	Remaining Nondeductible Contributions as of December 31, 2013
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
Total	0	0	0

2.9 Development of maximum deductible contribution – 401(h)

All monetary amounts shown in US Dollars

Plan Year Beginning			January 1, 2014
A	**Development of Maximum Deductible Contribution**		
	1	Present value of projected benefits	301,556,945
	2	Fair value of assets	354,307,378
	3	Unfunded surplus [1 - 2]	(52,750,433)
	4	Average present value of future service	12
	5	Preliminary maximum deductible contribution	
		a 10% of unfunded surplus [10% x A.3]	(5,275,043)
		b Aggregate normal cost [A.3 / A.4]	(4,395,869)
		c Greater of A.5.a, A.5.b and 0	0
	6	Preliminary maximum 2013 contribution [1.0753 x A.5.c]	0
	7	Subordination test (development shown below)	3,851,910
	8	Maximum deductible contribution ignoring expenses [lesser of A.6 and A.7]	0
	9	Total trust expenses paid from 401(h) account	1,450,085
	10	Maximum deductible contribution including expenses [A.8 + A.9]	1,450,085

B Subordination Test

Year-by-year minimum of actual pension plan contribution and pension plan normal cost with interest

	Year	West Plan	East Plan	Combined Plan
	1992	9,766,169	N/A	N/A
	1993	22,392,743	N/A	N/A
	1994	21,208,326	N/A	N/A
	1995	21,683,436	N/A	N/A
	1996	20,271,648	N/A	N/A
	1997 - 2002	0	N/A	N/A
	2003	19,197,145	39,165,054 *	N/A
	2004	18,614,338	56,614,811	N/A
	2005	16,222,550	55,872,817	N/A
	2006	0	0	N/A
	2007	0	0	N/A
	2008	N/A	N/A	0
	2009	N/A	N/A	100,540,448
	2010	N/A	N/A	125,586,018
	2011	N/A	N/A	62,751,522
	2012	N/A	N/A	0
	2013	N/A	N/A	0
Cumulative pension contributions not for past service		149,356,355	151,652,681	589,887,025
		x 1/3	x 1/3	x 1/3
		49,785,452	50,550,894	196,629,008
Cumulative 401(h) contributions before plan year 2014		49,785,452	50,550,894	192,777,098
Subordination limit		0	0	3,851,910

* Includes only portion of normal cost and contributions after 401(h) account adoption for indicated years.

TOWERS WATSON

2.10 Expected benefit disbursements, administrative expenses, and participant contributions

All monetary amounts shown in US Dollars

			January 1, 2014	January 1, 2013
A	**Medical and Dental**			
	1	Gross disbursements	117,516,479	114,982,040
	2	Participant contributions	(29,490,760)	(33,396,799)
	3	Net disbursements	88,025,719	81,585,241
B	**Life Insurance**			
	1	Gross disbursements	16,256,380	15,932,506
	2	Participant contributions	(1,503,593)	(3,434,791)
	3	Net disbursements	14,752,787	12,497,715
C	**Gross without RDS**			
	1	Gross disbursements	133,772,859	130,914,546
	2	Participant contributions	(30,994,353)	(36,831,590)
	3	Net disbursements	102,778,506	94,082,956
D	**RDS***			
	1	Gross disbursements	(80,443)	(67,791)
	2	Participant contributions	0	0
	3	Net disbursements	(80,443)	(67,791)
E	**Net with RDS**			
	1	Gross disbursements	133,692,416	130,982,337
	2	Participant contributions	(30,994,353)	(36,831,590)
	3	Net disbursements	102,698,063	94,150,747

* 2013-2014 RDS payments expected to be received in 2015-2016.

Section 3 : Data exhibits

3.1 Plan participant data

All monetary amounts shown in US Dollars

Census Date	January 1, 2014	January 1, 2013
A Participating Employees		
1 Number		
a Fully eligible	694	466
b Other[1]	17,868	18,111
c Total participating employees	18,562	18,577
2 Total annual compensation/salary	$1,352,753,749	$1,315,622,699
3 Average compensation/salary	$74,532	$72,722
4 Average age (years)	46.63	46.44
5 Average credited service (years)	17.04	16.99
6 Average future working life (years)		
a to full retirement age	11.696	11.921
b to full eligibility age	10.934	10.988
B Retirees and Surviving Spouses		
1 Retirees and Surviving Spouses		
a Number under 65	3,282	3,640
b Number 65 and older	13,167	12,826
c Total	16,449	16,466
d Average age (years)	73.4	73.1
e. Age Distribution at January 1, 2013		

Age	Number
Under 55	30
55-59	790
60-64	2,462
65-69	3,781
70-74	2,836
75-79	2,193
80-84	2,026
85 and over	2,331

[1] Includes 412 disabled participants in 2014 and 509 disabled participants in 2013. These participants were not included in the calculation of the other data statistics in this section.

Census Date	January 1, 2014	January 1, 2013
C Dependents		
1 Number	8,386	8,509
2 Average Age	68.4	68.0
3 Age Distribution at January 1, 2014		

Age	Number
Under 55	301
55-59	953
60-64	1,916
65-69	2,025
70-74	1,316
75-79	997
80-84	560
85 and over	318

3.2 Age and service distribution of participating employees

All monetary amounts shown in US Dollars

Attained Age		Attained Years of Credited Service and Number								
		0-4	5-9	10-14	15-19	20-24	25-29	30-34	Over 34	Total
Under 25	Count	374	14	0	0	0	0	0	0	388
	Total Earnings	$17,043,749	$666,220	$0	$0	$0	$0	$0	$0	$17,709,969
	Average Earnings	$45,572	$47,587	$0	$0	$0	$0	$0	$0	$45,644
25-29	Count	651	519	5	0	0	0	0	0	1,175
	Total Earnings	$34,367,753	$31,241,837	$313,245	$0	$0	$0	$0	$0	$65,922,835
	Average Earnings	$52,792	$60,196	$62,649	$0	$0	$0	$0	$0	$56,105
30-34	Count	565	1,027	185	4	0	0	0	0	1,781
	Total Earnings	$31,498,635	$68,155,586	$12,612,463	$226,116	$0	$0	$0	$0	$112,492,800
	Average Earnings	$55,750	$66,364	$68,175	$56,529	$0	$0	$0	$0	$63,163
35-39	Count	400	907	400	129	2	0	0	0	1,838
	Total Earnings	$22,715,631	$60,955,195	$30,171,485	$9,207,893	$145,913	$0	$0	$0	$123,196,116
	Average Earnings	$56,789	$67,205	$75,429	$71,379	$72,956	$0	$0	$0	$67,027
40-44	Count	295	746	424	308	127	6	0	0	1,906
	Total Earnings	$18,405,817	$51,978,546	$34,200,225	$23,699,975	$10,983,077	$370,576	$0	$0	$139,638,215
	Average Earnings	$62,393	$69,676	$80,661	$76,948	$86,481	$61,763	$0	$0	$73,262
45-49	Count	225	531	343	306	524	316	12	0	2,257
	Total Earnings	$14,223,755	$37,220,875	$28,242,172	$24,604,670	$45,884,337	$25,798,785	$829,894	$0	$176,804,488
	Average Earnings	$63,217	$70,096	$82,339	$80,407	$87,566	$81,642	$69,158	$0	$78,336
50-54	Count	167	415	266	299	450	958	880	52	3,487
	Total Earnings	$10,550,155	$29,744,248	$21,401,924	$22,752,208	$36,216,957	$82,447,248	$73,770,585	$3,960,518	$280,843,844
	Average Earnings	$63,175	$71,673	$80,458	$76,094	$80,482	$86,062	$83,830	$76,164	$80,540
55-59	Count	131	278	178	175	321	608	1,099	765	3,555
	Total Earnings	$8,731,784	$20,549,371	$15,221,089	$13,010,460	$25,574,985	$49,848,426	$96,148,930	$63,536,000	$292,621,045
	Average Earnings	$66,655	$73,919	$85,512	$74,345	$79,673	$81,988	$87,488	$83,054	$82,313
60-64	Count	49	147	95	86	131	225	319	466	1,518
	Total Earnings	$3,134,284	$11,072,642	$7,400,733	$7,490,071	$9,346,867	$18,172,569	$27,028,082	$40,027,608	$123,672,855
	Average Earnings	$63,965	$75,324	$77,902	$87,094	$71,350	$80,767	$84,728	$85,896	$81,471
65-69	Count	0	38	29	18	17	31	28	58	219
	Total Earnings	$0	$2,804,097	$2,615,636	$1,278,499	$1,160,164	$2,260,515	$2,621,214	$5,137,257	$17,877,382
	Average Earnings	$0	$73,792	$90,194	$71,028	$68,245	$72,920	$93,615	$88,573	$81,632
70 & over	Count	0	0	12	3	5	3	2	1	26
	Total Earnings	$0	$0	$971,979	$133,783	$427,693	$213,410	$176,627	$50,708	$1,974,199
	Average Earnings	$0	$0	$80,998	$44,594	$85,539	$71,137	$88,313	$50,708	$75,931
Total	Count	2,857	4,622	1,937	1,328	1,577	2,147	2,340	1,342	18,150
	Total Earnings	$160,671,562	$314,388,615	$153,150,951	$102,403,675	$129,739,993	$179,111,529	$200,575,332	$112,712,091	$1,352,753,748
	Average Earnings	$56,238	$68,020	$79,066	$77,111	$82,270	$83,424	$85,716	$83,988	$74,532

Average:	Age	47	Number of Participants:	Fully eligible	694	Males	14,913
	Service	17		Other	17,868	Females	3,237

Census data as of January 1, 2014

This page is intentionally blank

Appendix A : Statement of actuarial assumptions and methods

Actuarial Assumptions and Methods — Postretirement Welfare Cost and Funding/Tax Deductions Based on Plan Year beginning January 1, 2014

Economic Assumptions

	Postretirement Welfare Cost	Plan Reporting	Employer Contributions
Discount rate[1]	4.70 %	4.70 %	N/A
Rates of return on assets, pre-tax: [1]			
401(h) accounts	N/A	N/A	7.53 %
Life insurance and union medical/dental	N/A	N/A	6.60 %
Non-union medical/dental	N/A	N/A	6.64 %
Aggregate	6.75 %	N/A	N/A

Annual rates of compensation increase[1]

Representative rates	Age	Rate
	< 26	11.50%
	26 – 30	9.50
	31 – 35	7.50
	36 – 40	6.50
	41 – 45	5.00
	46 – 50	4.00
	> 50	3.50
Weighted average	4.95%	

Medical cost trend rate[2]	2014	6.50%
	2015	6.25%
	2016	6.00%
	2017	5.75%
	2018	5.50%
	2019	5.25%
	2020+	5.00%
Dental cost trend rate[2]	2014+	5.00%

[1] Only discount rate and asset return assumptions vary between the reporting standards. All other assumptions are consistent throughout.

[2] 0% trend assumed for non-union VEBA account limit.

Participation Assumptions

Inclusion Date	The valuation date coincident with or next following the date on which the employee is hired.	
New or rehired employees	It was assumed there will be no new or rehired employees.	
	Current Retirees	*Future Retirees*
Participation	Based on valuation census data.	95% in 2014 and 2015 with the rate decreasing by 5% annually beginning in 2016 to an ultimate rate of 75% in 2019.
Persistency	Non-capped retirees will drop coverage at a rate of 2% annually and Capped retirees will drop coverage at a rate of 4% annually.	Same as current retirees
Percent married	Based on valuation census data.	69% for males, 50% for females.
Spouse age	Based on valuation census data.	Wife three years younger than husband.

Demographic Assumptions

Mortality

Preretirement: RP2000, projected to 2029.
Postretirement: RP2000, projected to 2021.

Disabled mortality (through age 65)

Rates vary by age and sex.

Representative rates:

Age	*Males*	*Females*
30	2.60%	2.60%
40	2.60	2.60
50	3.10	3.10
60	6.20	6.20

Disability

Rates apply to employees not eligible to retire and vary by age and sex.

Representative rates:

Percentage becoming disabled during the year		
Age	Males	Females
20	0.060%	0.090%
30	0.060	0.090
40	0.074	0.110
50	0.178	0.270
60	0.690	1.035

Termination (not due to disability or retirement)

Rates apply to employees not eligible to retiree and vary by age and service.

Representative rates:

Percentage leaving during the year		
Age	0 – 5 Years	5+ Years
20	8.0%	8.0%
30	8.0	5.0
40	8.0	2.5
50	8.0	4.0
60	8.0	4.0

Retirement

Rates vary by age.

Representative rates:

Percentage retiring during the year	
Age	Rate
55 – 57	7.0%
58 – 60	10.0
61 – 63	25.0
64 – 65	50.0
66 – 69	25.0
70	100.0

2014 Per Capita Claims Costs

Medical

Prior to age 65

Age	Aetna	Lumenos
< 50	5,957	6,061
50 – 54	6,958	7,081
55 – 59	7,749	7,885
60 – 64	10,543	10,728
Average	9,425	9,591

Age 65 and after (net of Medicare Parts A & B)

Age	COB	MOB	CSP
65 – 69	3,525	2,920	1,500
70 – 74	4,095	3,377	1,755
75 – 79	4,415	3,618	1,905
80 – 84	4,602	3,744	1,980
85 – 89	4,779	3,862	2,055
90 – 94	4,594	3,686	2,025
≥ 95	4,056	3,219	1,875
Average	4,258	3,217	1,976

Medicare Part D - RDS

Age	MOB/COB	CSP
65 – 69	N/A	(260)
70 – 74	N/A	(293)
75 – 79	N/A	(304)
80 – 84	N/A	(301)
85 – 89	N/A	(299)
90 – 94	N/A	(273)
≥ 95	N/A	(221)
Average	N/A	(286)

Medicare Part D - Employer Group Waiver Plan (EGWP) for MOB/COB

Age	CMS Direct Payments & Catastrophic Reinsurance	Manufacturer's Discount
65 – 69	(438)	(294)
70 – 74	(494)	(332)
75 – 79	(512)	(344)
80 – 84	(508)	(341)
85 – 89	(503)	(338)
90 – 94	(459)	(308)
≥ 95	(372)	(250)
Average	(482)	(323)

Expected EGWP subsidies for direct payments plus catastrophic reinsurance increase in future years at rates different than the annual trend assumption due to the progressive filling in of the Standard Part D “donut hole” between 2014 and 2020.

2014	12.1%
2015	8.2
2016	14.4
2017	13.5
2018	12.7
2019	13.1
2020+	5.0

Dental	$308
Medicare covered charges trend rate	Same as medical cost trend, except for growth in expected EGWP subsidies differ as shown above.
Retiree contribution trend rate	Same as medical cost trend. For capped retirees, future retiree contributions are developed based on expected gross costs compared to the applicable cap.
Administrative expenses	Included in claims costs shown above.

Basis for Per Capita Claims Cost Assumptions

Pre-65 retiree medical rates	Aetna, Medco, Lumenos and Magellan supplied data on retiree medical claims incurred in 2012. Claim experience rates are calculated for Aetna and Lumenos plans by dividing incurred claims by covered lives and trending forward two years to 2014. Adjustments for benefit, geographic and vendor efficiency differences are also made. Medical and prescription drug claim rates are then multiplied by plan change factors representing the effect of any substantive plan design changes for 2014. Aetna and Lumenos claims cost models are developed separately by age-grading these claims rates over standard Towers Watson morbidity curves for both medical and prescription drugs to develop the quinquennial claims cost models.
Post-65 retiree medical rates	2014 monthly claim rates are calculated separately for MOB, COB and CSP Medicare-eligible plans by dividing 2012 incurred claims by covered lives and trending forward two years to 2014. Prescription drug claim rates are then multiplied by pricing change factors representing the effect of any substantive design changes for 2014. MOB and COB claims cost models are developed separately by age-grading these claim rates over standard Towers Watson morbidity curves for both medical and prescription drugs to develop the quinquennial claims cost models.
Dental rates	Aetna supplied data on dental claims incurred in 2012. Claims experience for all active and retired employees was analyzed to derive the dental claim rates.
Medicare Part D Retiree Drug Subsidy (RDS)	We calibrated our modelling tool to reflect the 2014 cost of the current prescription drug plans for AEP’s post-65 retirees. The tool employs a continuance table of annual retiree drug utilization levels, developed from analyzing the experience of several large Towers Watson clients. After the plan-specific benefit provisions have been calibrated to

current costs, the Modeler trends costs forward to 2014. Actuarial equivalence was determined using the following two-prong approach outlined in the regulations for Medicare Part D:

Gross Value Test – The Modeler calculates the value of standard Medicare Part D coverage and compares it to AEP's plan costs. AEP's plans passed this test by being richer than the projected value of standard Medicare part D coverage for these groups.

Net Value Test – The net value prong of the test compares the value of Standard Part D coverage in 2014 minus the greater of $389.04 per year (the national average Part D premium) and 25.5% of the gross value of Part D to the projected 2014 value of AEP coverage minus the average projected 2014 retiree contribution rate. For this purpose, retiree contributions were assumed to apply pro rata between the value of medical benefits and prescription drug benefits.

When the plans are deemed to be actuarially equivalent, the tool calculates the average expected value of the employer subsidy in 2013, using the continuance table calibrated to AEP's plan costs. This produced a 2014 per person employer subsidy of $286 for CSP.

Employer Group Waiver Plan (EGWP)

Estimated plan cost offsets associated with transitioning to an EGWP arrangement were developed using the same post-65 retiree prescription drug continuance table that was used in the Retiree Drug Subsidy payment estimates. AEP's plan-specific benefit provisions were calibrated to current costs to estimate the level of pharmaceutical company discounts and reinsurance dollars that the plan would receive for participants who enter or exceed the Standard Medicare Part D "donut hole." An estimate of direct monthly government payments under the EGWP was provided by Express Scripts based on average Part D plan payments risk-adjusted for AEP's post-65 retiree population.

To account for the gradual fill-in of the "donut hole" through 2020, higher trend levels are applied to estimated direct monthly EGWP payments between 2014 (effective date of plan change) and 2020, after which EGWP plan cost offsets are assumed to increase at the valuation trend rate assumption.

Additional Assumptions

Excise tax

To determine impact of the excise tax on the non-UMWA postretirement plan, we projected future gross plan costs using the valuation trend assumption and compared these on a year-by-year basis to the excise tax thresholds beginning in 2018 and projected to future years using CPI (CPI + 1% for 2019). The expected cost of each non-UMWA benefit combination, which were blended pre-65/post-65 based on headcounts, exceeded these thresholds at various points in time, but no earlier than 2040.

The amount of the excise tax valued was 40% times the portion of the cost exceeding the thresholds, grossed up by 35% to account for the nondeductibility of these charges for AEP's administrators.

Timing of benefit payments

Benefit payments are assumed to be made uniformly throughout the year and on average at mid-year.

Methods

Census date	January 1, 2014
Measurement date	January 1, 2014
Service cost and APBO	Costs are determined using the Projected Unit Credit Cost Method. The annual service cost is equal to the present value of the portion of the projected benefit attributable to service during the upcoming year, and the Accumulated Postretirement Benefit Obligation (APBO) is equal to the present value of the portion of the projected benefit attributable to service before the valuation date. Service from hire date through the expected full eligibility date is counted in allocating costs.
Market-related value of assets	The fair value of assets on the measurement date.
Amortization of unamortized amounts:	
Prior service cost (credit)	Increase in APBO resulting from a plan amendment is amortized on a straight-line basis over the average expected remaining service of active participants expected to benefit under the plan. Amortization of net prior service cost/(credit) resulting from a plan change is included as a component of Net Periodic Postretirement Benefit Cost/(Income) in the year first recognized and every year thereafter until such time as it is fully amortized. The annual amortization payment is determined in the first year as the increase in APBO due to the plan change divided by the average remaining service period to full eligibility for participating employees expected to receive benefits under the Plan. Reductions in APBO first reduce any unrecognized prior service cost; any remaining amount is amortized on a straight-line basis as described above.
Net loss (gain)	Amortization of the net gain or loss resulting from experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of Net Periodic Postretirement Benefit Cost/(Income) for a year. Net loss (gain) in excess of 10% of the greater of APBO or the market-related value of assets is amortized on a straight-line basis over the average expected remaining service of active participants expected to benefit under the plan.
ASC 965 (formerly SOP 92-6)	
Present value of benefits	Present value of benefits is equal to the present value of the portion of the projected benefit attributable to service before the valuation date. Service from hire date through the expected full eligibility date is counted in allocating costs.
Funding policy	AEP's funding policy is to contribute an amount equal to the postretirement welfare cost plus retiree drug subsidy payments received (the sum of which can be no less than zero). AEP maximizes its contribution to the 401(h) account and contributes the remainder to the VEBAs.

Benefits Not Valued	All benefits described in the Plan Provisions section of this report were valued. Life insurance benefits in excess of $50,000 and health care benefits for key employees were not included in determining the maximum deductible contribution. Towers Watson has reviewed the plan provisions with AEP and based on that review is not aware of any significant benefits required to be valued that were not included.
Change in Assumptions and Methods Since Prior Valuation	The discount rate for APBO was changed from 3.95% to 4.70%. Mortality was updated to reflect an additional year of mortality improvements. Per capita claims costs were updated to reflect 2012 claims experience. The percentage of future retirees electing coverage decreased from 95% for all years to 95% in 2014 and 2015 with the rate decreasing by 5% annually beginning in 2016 to an ultimate rate of 75% in 2019. A persistency assumption was added stating that beginning in 2014. Non-capped retirees will drop coverage at a rate of 2% annually and Capped retirees will drop coverage at a rate of 4% annually.

Data Sources

American Electric Power (AEP), through its third party administrator, furnished active participant data as of January 1, 2014. AEP provided inactive participant data as of January 1, 2014. AEP also provided the accrued postretirement benefit costs as of December 31, 2013. Health plan vendors furnished the claims cost data. Data were reviewed for reasonableness and consistency, but no audit was performed. Based on discussions with the plan sponsor, assumptions or estimates were made when data were not available, and the data was adjusted to reflect any significant events that occurred between the date the data was collected and the measurement date. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Appendix B : Summary of substantive plan provisions

Health Care Benefits

Eligibility	Participants are eligible upon retirement after age 55 with ten years of service or upon attaining age 55 with ten years of service after becoming permanently disabled. If involuntary termination, then eligible after age 50 with ten years of service. Employees hired on or after January 1, 2014 are not eligible to participate in the plan.
Surviving spouse	After the death of a retiree or active employee eligible to retire, surviving spouses are eligible until death or remarriage. Surviving children are also eligible, subject to the limiting age provision outlined above.
Dependent	Eligible dependents are spouse, unmarried children under age 19 (age 25 if a full-time student) and unmarried disabled children of any age.
Benefits	The AEP Post-65 Medical Plan provides broad medical coverage with a deductible of $200, 80% coinsurance and a maximum annual out-of-pocket expense of $2,000 per person. Discounted charges and different benefits ($250 deductible, 85% coinsurance and a $2,500 out-of-pocket maximum) may be obtained by pre-65 retirees electing to use Aetna network providers. Pre-65 retirees who live in areas designated as "Network Area" will have reduced benefits ($500 deductible, 70% coinsurance, $5,000 out-of-pocket maximum) if they do not use network providers. Alternatively, these retirees can elect coverage under consumer driven health plan designs. Prescription drug benefits are provided under a separate design with the following copayments for those who do not enroll in a consumer driven health plan:

	Generic	*Brand Name Formulary*	*Brand Name Nonformulary*
30-day retail	$5 copay	20% $20 minimum $100 maximum	20% $35 minimum $200 maximum
90-day retail	$12 copay	20% $50 minimum $200 maximum	20% $90 minimum $300 maximum

Prescription drug benefits are also subject to a $50 deductible and a $1,000 out-of-pocket maximum per person.

Benefits after age 65 are coordinated with Medicare using the carve-out method (MOB benefits). Participants have the option to "buy up" to exclusion coordination of benefits coverage (COB benefits). Exclusion coordination is automatically provided to East retirees who attained age 65 prior to January 1, 2001.

Deductibles and out-of-pocket maximums are assumed to increase over time at approximately the same rate as benefit costs.

Postretirement contributions

Participant contributions are determined as a percentage of plan costs and vary by points (age at retirement plus service) as follows:

Points	*Retiree Cost*
65-69	46%
70-74	42
75-79	36
80-84	32
85-89	26
90-94	22
95+	20
Grandfathered	20

For participants retiring on or after January 1, 2013, AEP's subsidy is capped at $11,500 and $3,500 times employer cost sharing percentage for pre-65 and post-65 participants, respectively.

For East participants who retired prior to January 1, 1989, and West participants who retired prior to January 1, 1993, no contributions are required.

For East participants who retired on or after January 1, 1989, and West participants who retired on or after January 1, 1993, the 20% "Grandfathered" contributions are in effect if they retired by December 31, 2000, or attained age 50 and had ten or more years of service with the company on that date. The percentages described above are applied to plan costs that differ from the per capita claims costs assumed in the valuation as follows:

The Medicare status of dependents is not used to determine whether "pre-65" or "post-65" rates apply. The pre-65 plan rates used to calculate participant contributions are a blend of pre-65 retiree costs and active employee costs for those participants retired prior to January 1, 2013, only.

For purposes of determining retiree contribution rates, AEP excludes the government's monthly direct payment amount from offsetting the plan cost to which the contribution percentages are applied.

Disabled employee contributions

Disabled employees have a provision where active employee contribution rates are charged while an employee remains disabled and is receiving LTD benefits.

If an employee retires while disabled and became disabled before January 1, 2001, the waiver of premium provision continues for life as long as the retirement commenced on or before September 1, 2013. If an employee retires while disabled and became disabled after January 1, 2001, the employee will continue to accrue points as if actively-at-work until age 65 and be subject to the same contribution schedule as normal retirees.

Those participants retiring after January 1, 2013, pay a percentage of true pre-65 retiree costs.

Life Insurance Benefits

Grandfathered participants

Participants over age 50 with ten years of service as of December 31, 2000.

Grandfathered benefits

Grandfathered participants have the option of keeping current coverage. Active employee coverage for grandfathered East participants is one times final base pay at no cost with the option to buy up to two times base pay. The entire amount of coverage (basic plus supplemental) in force prior to retirement can be carried into retirement subject to reduction beginning at age 66. Current coverage for grandfathered West participants is one and one-half times final base pay prior to age 60, one times final base pay from age 60 to 64 and one-half times final base pay after age 65.

Life Insurance Benefit Reduction Table
for Grandfathered East Participants

Years of Coverage	*Age 66*	*Age 67*	*Age 68*	*Age 69*	*Age 70 or Over*
10 – 11	65%	55%	45%	35%	25%
11 – 12	70	60	50	40	30
12 – 13	75	65	55	45	35
13 – 14	80	70	60	50	40
14 – 15	85	75	65	55	45
15 or more	90	80	70	60	50

Grandfathered contributions

Grandfathered East retirees must contribute $0.60/$1,000 of coverage (basic + supplemental) per month. West retirees are not required to contribute to the cost of coverage.

Nongrandfathered benefits

$30,000 for those hired before January 1, 2011. No benefit for those hired on or after January 1, 2011.

Dental Benefits

Eligibility

Participants, including retirees and surviving dependents, are eligible upon retirement after age 55 with ten years of service. There is a one-time election and if coverage terminates there is no opportunity to reenroll.

Employees hired on or after January 1, 2014 are not eligible to participate in the plan.

Benefits

The AEP Dental Plan provides dental coverage with a deductible of $50 single/$150 family, 100% coinsurance for preventive care, 80% coinsurance for basic restorative care, 50% coinsurance for major restorative care and 50% coinsurance for orthodontia.

Most retirees pay the full cost of dental coverage if they enroll. CSW employees who retire before January 1, 1993, contribute nothing to enroll for dental coverage. Former CSW employees retiring after January 1, 1993, who were either retired or had attained age 50 with ten years of service as of January 1, 2001, pay 30%.

Changes in Benefits Valued Since Prior Year

None

Overview of Benefits Provided by Funding Vehicles

Funding vehicle	Provides for
Non-union postretirement medical/dental VEBAs	100% of medical benefits to non-union employees before 2016 and 50% of retiree medical benefits thereafter. 100% of dental benefits to non-union employees.
Union postretirement medical/dental VEBAs	100% of medical/dental benefits to union employees.
Postretirement life insurance VEBA	Life insurance benefits for all retirees.
401(h) account	50% of retiree medical benefits after 2015 for non-union retirees.

Appendix C : Results by business unit

Summary of key assumptions for Appendix C of 2014 NUMWA Postretirement Health Care Plan valuation report:

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Discount Rate	4.70%	5.30%	5.50%	5.60%	5.70%	5.80%	5.80%	5.80%	5.80%	5.80%	5.80%
Expected Return on Assets	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%	6.75%
Initial Medical Trend	6.50%	6.25%	6.00%	5.75%	5.50%	5.25%	5.00%	5.00%	5.00%	5.00%	5.00%

Expected mortality	IRS-prescribed mortality table for minimum funding purposes, with adoption of RP-2014 and projection scale MP-2014 at year end 2015.
Valuation and data	January 1, 2014
Per capita claims costs	2014 cost models based on actual claims experience incurred through December 31, 2012.

Non-UMWA PRW Plan participation assumption: 95% of future retirees will elect coverage in 2014 and 2015, with rate decreasing by 5% annually beginning in 2016 to ultimate rate of 75% in 2019+.
Non-UMWA PRW Plan persistency assumption: Beginning in 2014, non-capped retirees will drop coverage at a rate of 2% annually; Capped retirees will drop coverage at a rate of 4% annually.
Includes Transitional Reinsurance Fees and Comparative Effectiveness fees under Health Care Reform

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
SUMMARY OF PLAN PARTICIPANTS FOR THE 2014 VALUATION

	Nonretired Participants			Retired Participants			
Location	**Active**	**Disabled**	**Total**	**Retiree**	**Dependent Spouse**	**Surviving Spouse**	**Total**
140 Appalachian Power Co. - Distribution	1,026	38	1,064	1,139	741	342	2,222
215 Appalachian Power Co. - Generation	878	47	925	898	620	204	1,722
150 Appalachian Power Co. - Transmission	57	8	65	137	105	6	248
Appalachian Power Co. - FERC	**1,961**	**93**	**2,054**	**2,174**	**1,466**	**552**	**4,192**
225 Cedar Coal Co	0	0	0	13	5	15	33
Appalachian Power Co. - SEC	**1,961**	**93**	**2,054**	**2,187**	**1,471**	**567**	**4,225**
211 AEP Texas Central Company - Distribution	904	29	933	900	555	266	1,721
147 AEP Texas Central Company - Generation	0	0	0	0	0	0	0
169 AEP Texas Central Company - Transmission	115	1	116	80	46	30	156
AEP Texas Central Co.	**1,019**	**30**	**1,049**	**980**	**601**	**296**	**1,877**
170 Indiana Michigan Power Co. - Distribution	581	6	587	664	377	237	1,278
132 Indiana Michigan Power Co. - Generation	380	7	387	274	183	82	539
190 Indiana Michigan Power Co. - Nuclear	1,158	17	1,175	393	259	52	704
120 Indiana Michigan Power Co. - Transmission	131	1	132	124	88	10	222
280 Ind Mich River Transp Lakin	319	20	339	119	49	27	195
Indiana Michigan Power Co. - FERC	**2,569**	**51**	**2,620**	**1,574**	**956**	**408**	**2,938**
202 Price River Coal	0	0	0	0	0	0	0
Indiana Michigan Power Co. - SEC	**2,569**	**51**	**2,620**	**1,574**	**956**	**408**	**2,938**
110 Kentucky Power Co. - Distribution	246	12	258	180	94	60	334
117 Kentucky Power Co. - Generation	85	9	94	125	89	31	245
180 Kentucky Power Co. - Transmission	32	1	33	16	13	0	29
600 Kentucky Power Co. - Kammer Actives	39	0	39	0	0	0	0
701 Kentucky Power Co. - Mitchell Actives	240	0	240	0	0	0	0
702 Kentucky Power Co. - Mitchell Inactives	0	4	4	96	73	6	175
Kentucky Power Co.	**642**	**26**	**668**	**417**	**269**	**97**	**783**
250 Ohio Power Co. - Distribution	1,528	26	1,554	1,717	1,010	427	3,154
160 Ohio Power Co. - Transmission	13	4	17	229	160	49	438
Ohio Power Co.	**1,541**	**30**	**1,571**	**1,946**	**1,170**	**476**	**3,592**
167 Public Service Co. of Oklahoma - Distribution	679	16	695	534	336	158	1,028
198 Public Service Co. of Oklahoma - Generation	371	6	377	214	137	55	406
114 Public Service Co. of Oklahoma - Transmission	95	3	98	55	38	13	106
Public Service Co. of Oklahoma	**1,145**	**25**	**1,170**	**803**	**511**	**226**	**1,540**
159 Southwestern Electric Power Co. - Distribution	524	10	534	326	203	84	613
168 Southwestern Electric Power Co. - Generation	597	11	608	271	184	78	533
161 Southwestern Electric Power Co. - Texas - Distribution	241	7	248	154	97	39	290
111 Southwestern Electric Power Co. - Texas - Transmission	0	0	0	0	0	0	0
194 Southwestern Electric Power Co. - Transmission	84	1	85	54	34	17	105
Southwestern Electric Power Co.	**1,446**	**29**	**1,475**	**805**	**518**	**218**	**1,541**
119 AEP Texas North Company - Distribution	252	13	265	241	138	66	445
166 AEP Texas North Company - Generation	0	0	0	114	62	38	214
192 AEP Texas North Company - Transmission	59	0	59	35	18	8	61
AEP Texas North Co.	**311**	**13**	**324**	**390**	**218**	**112**	**720**
230 Kingsport Power Co. - Distribution	52	1	53	50	31	15	96
260 Kingsport Power Co. - Transmission	5	1	6	7	3	1	11
Kingsport Power Co.	**57**	**2**	**59**	**57**	**34**	**16**	**107**
210 Wheeling Power Co. - Distribution	46	3	49	62	41	31	134
200 Wheeling Power Co. - Transmission	0	0	0	3	2	9	14
Wheeling Power Co.	**46**	**3**	**49**	**65**	**43**	**40**	**148**
103 American Electric Power Service Corporation	5,344	54	5,398	2,732	1,639	239	4,610
American Electric Power Service Corporation	**5,344**	**54**	**5,398**	**2,732**	**1,639**	**239**	**4,610**
143 AEP Pro Serv, Inc.	0	0	0	1	1	0	2
171 CSW Energy, Inc.	90	0	90	8	1	0	9
293 Elmwood	81	3	84	18	4	0	22
292 AEP River Operations LLC	949	17	966	57	21	0	78
189 Central Coal Company	0	0	0	0	0	0	0
Miscellaneous	**1,120**	**20**	**1,140**	**84**	**27**	**0**	**111**
270 Cook Coal Terminal	22	0	22	8	6	2	16
AEP Generating Company	**22**	**0**	**22**	**8**	**6**	**2**	**16**
104 Cardinal Operating Company	300	5	305	197	134	46	377
181 Ohio Power Co. - Generation	627	31	658	1,171	778	276	2,225
AEP Generation Resources - FERC	**927**	**36**	**963**	**1,368**	**912**	**322**	**2,602**
290 Conesville Coal Preparation Company	0	0	0	13	11	1	25
AEP Generation Resources - SEC	**927**	**36**	**963**	**1,381**	**923**	**323**	**2,627**
Total	**18,150**	**412**	**18,562**	**13,429**	**8,386**	**3,020**	**24,835**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
2014 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$118,157,017	$9,669,233	$145,663,119	$759,058	$5,364,438	($9,536,297)	($5,097,397)	$1,678,464	($6,831,734)
215 Appalachian Power Co. - Generation	$97,377,175	$7,844,094	$120,045,879	$652,670	$4,425,183	($7,859,184)	($4,162,884)	$1,383,279	($5,560,936)
150 Appalachian Power Co. - Transmission	$13,122,077	$998,263	$16,176,802	$35,802	$595,231	($1,059,066)	($781,538)	$186,404	($1,023,167)
Appalachian Power Co. - FERC	**$228,656,270**	**$18,511,589**	**$281,885,800**	**$1,447,530**	**$10,384,852**	**($18,454,547)**	**($10,041,819)**	**$3,248,147**	**($13,415,837)**
225 Cedar Coal Co	$968,900	$131,773	$1,194,453	$0	$42,477	($78,199)	($8,202)	$13,764	($30,160)
Appalachian Power Co. - SEC	**$229,625,170**	**$18,643,362**	**$283,080,253**	**$1,447,530**	**$10,427,329**	**($18,532,746)**	**($10,050,021)**	**$3,261,911**	**($13,445,997)**
211 AEP Texas Central Company - Distribution	$83,219,618	$6,492,837	$102,592,545	$642,132	$3,790,672	($6,716,546)	($3,881,048)	$1,182,165	($4,982,625)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$7,537,590	$558,466	$9,292,286	$73,815	$344,763	($608,349)	($391,921)	$107,074	($474,618)
AEP Texas Central Co.	**$90,757,208**	**$7,051,303**	**$111,884,831**	**$715,947**	**$4,135,435**	**($7,324,895)**	**($4,288,306)**	**$1,289,239**	**($5,472,580)**
170 Indiana Michigan Power Co. - Distribution	$58,886,073	$5,123,042	$72,594,326	$420,670	$2,668,408	($4,752,617)	($2,601,438)	$836,498	($3,428,479)
132 Indiana Michigan Power Co. - Generation	$32,934,203	$2,421,875	$40,601,048	$304,351	$1,505,951	($2,658,076)	($1,850,054)	$467,842	($2,229,986)
190 Indiana Michigan Power Co. - Nuclear	$50,585,607	$3,235,097	$62,361,571	$938,318	$2,346,473	($4,082,698)	($3,561,730)	$718,587	($3,641,050)
120 Indiana Michigan Power Co. - Transmission	$11,777,027	$870,402	$14,518,634	$85,089	$537,300	($950,508)	($596,815)	$167,297	($757,637)
280 Ind Mich River Transp Lakin	$12,515,063	$774,793	$15,428,480	$198,914	$579,558	($1,010,074)	($811,278)	$177,781	($865,099)
Indiana Michigan Power Co. - FERC	**$166,697,973**	**$12,425,210**	**$205,504,059**	**$1,947,342**	**$7,637,690**	**($13,453,973)**	**($9,421,315)**	**$2,368,005**	**($10,922,251)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$166,697,973**	**$12,425,210**	**$205,504,059**	**$1,947,342**	**$7,637,690**	**($13,453,973)**	**($9,421,315)**	**$2,368,005**	**($10,922,251)**
110 Kentucky Power Co. - Distribution	$21,384,752	$1,584,274	$26,362,968	$161,414	$975,867	($1,725,935)	($1,210,578)	$303,778	($1,495,454)
117 Kentucky Power Co. - Generation	$14,385,672	$1,073,051	$17,734,552	$58,348	$653,942	($1,161,049)	($611,828)	$204,354	($856,233)
180 Kentucky Power Co. - Transmission	$2,028,778	$138,214	$2,501,063	$20,958	$93,127	($163,740)	($198,150)	$28,820	($218,985)
600 Kentucky Power Co. - Kammer Actives	$1,101,990	$9,347	$1,358,525	$38,072	$53,366	($88,940)	($42,530)	$15,654	($24,378)
701 Kentucky Power Co. - Mitchell Actives	$5,375,970	$30,388	$6,627,457	$193,796	$261,073	($433,887)	($160,767)	$76,368	($63,417)
702 Kentucky Power Co. - Mitchell Inactives	$8,249,696	$870,798	$10,170,166	$0	$367,507	($665,822)	($200,743)	$117,190	($381,868)
Kentucky Power Co.	**$52,526,857**	**$3,706,072**	**$64,754,731**	**$472,588**	**$2,404,882**	**($4,239,373)**	**($2,424,596)**	**$746,164**	**($3,040,335)**
250 Ohio Power Co. - Distribution	$149,118,692	$12,162,005	$183,832,448	$1,018,052	$6,773,901	($12,035,173)	($5,890,962)	$2,118,286	($8,015,896)
160 Ohio Power Co. - Transmission	$18,388,360	$1,592,521	$22,669,038	$7,709	$827,621	($1,484,100)	($1,031,548)	$261,213	($1,419,105)
Ohio Power Co.	**$167,507,052**	**$13,754,526**	**$206,501,486**	**$1,025,761**	**$7,601,522**	**($13,519,273)**	**($6,922,510)**	**$2,379,499**	**($9,435,001)**
167 Public Service Co. of Oklahoma - Distribution	$49,017,029	$3,709,829	$60,427,840	$473,165	$2,239,859	($3,956,100)	($2,477,659)	$696,305	($3,024,430)
198 Public Service Co. of Oklahoma - Generation	$23,322,978	$1,605,694	$28,752,399	$302,793	$1,073,111	($1,882,367)	($1,498,642)	$331,311	($1,673,794)
114 Public Service Co. of Oklahoma - Transmission	$5,720,671	$476,378	$7,052,402	$63,397	$260,785	($461,708)	($313,349)	$81,264	($369,611)
Public Service Co. of Oklahoma	**$78,060,678**	**$5,791,901**	**$96,232,641**	**$839,355**	**$3,573,755**	**($6,300,175)**	**($4,289,650)**	**$1,108,880**	**($5,067,835)**
159 Southwestern Electric Power Co. - Distribution	$33,352,261	$2,356,757	$41,116,427	$366,001	$1,530,010	($2,691,817)	($1,794,965)	$473,781	($2,116,990)
168 Southwestern Electric Power Co. - Generation	$32,483,420	$2,204,904	$40,045,325	$440,234	$1,496,191	($2,621,694)	($2,137,691)	$461,439	($2,361,521)
161 Southwestern Electric Power Co. - Texas - Distribution	$15,805,678	$1,140,657	$19,485,126	$158,283	$723,808	($1,275,655)	($942,674)	$224,525	($1,111,713)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$5,290,957	$407,667	$6,522,654	$47,535	$241,439	($427,026)	($280,205)	$75,160	($343,097)
Southwestern Electric Power Co.	**$86,932,316**	**$6,109,985**	**$107,169,532**	**$1,012,053**	**$3,991,448**	**($7,016,192)**	**($5,155,535)**	**$1,234,905**	**($5,933,321)**
119 AEP Texas North Company - Distribution	$23,093,100	$1,676,795	$28,469,007	$197,018	$1,055,683	($1,863,814)	($1,276,048)	$328,046	($1,559,115)
166 AEP Texas North Company - Generation	$6,619,112	$614,112	$8,159,993	$0	$296,832	($534,220)	($67,677)	$94,027	($211,038)
192 AEP Texas North Company - Transmission	$2,906,286	$177,266	$3,582,849	$38,020	$134,264	($234,563)	($233,844)	$41,285	($254,838)
AEP Texas North Co.	**$32,618,498**	**$2,468,173**	**$40,211,849**	**$235,038**	**$1,486,779**	**($2,632,597)**	**($1,577,569)**	**$463,358**	**($2,024,991)**
230 Kingsport Power Co. - Distribution	$4,589,372	$380,110	$5,657,744	$38,726	$208,691	($370,402)	($177,403)	$65,194	($235,194)
260 Kingsport Power Co. - Transmission	$565,307	$42,890	$696,907	$2,365	$25,684	($45,625)	($40,419)	$8,030	($49,965)
Kingsport Power Co.	**$5,154,679**	**$423,000**	**$6,354,651**	**$41,091**	**$234,375**	**($416,027)**	**($217,822)**	**$73,224**	**($285,159)**
210 Wheeling Power Co. - Distribution	$6,062,819	$527,131	$7,474,200	$37,214	$274,456	($489,322)	($259,071)	$86,125	($350,598)
200 Wheeling Power Co. - Transmission	$370,008	$47,132	$456,143	$0	$16,295	($29,863)	($2,613)	$5,256	($10,925)
Wheeling Power Co.	**$6,432,827**	**$574,263**	**$7,930,343**	**$37,214**	**$290,751**	**($519,185)**	**($261,684)**	**$91,381**	**($361,523)**
103 American Electric Power Service Corporation	$299,312,497	$20,190,069	$368,990,290	$3,652,339	$13,770,331	($24,157,117)	($17,282,221)	$4,251,844	($19,764,824)
American Electric Power Service Corporation	**$299,312,497**	**$20,190,069**	**$368,990,290**	**$3,652,339**	**$13,770,331**	**($24,157,117)**	**($17,282,221)**	**$4,251,844**	**($19,764,824)**
143 AEP Pro Serv, Inc.	$145,010	$15,539	$178,767	$0	$6,454	($11,704)	($1,133)	$2,060	($4,323)
171 CSW Energy, Inc.	$932,330	$13,054	$1,149,370	$49,139	$45,826	($75,247)	($47,052)	$13,244	($14,090)
293 Elmwood	$1,795,917	$76,131	$2,213,994	$83,888	$86,582	($144,946)	($276,067)	$25,512	($225,031)
292 AEP River Operations LLC	$9,465,286	$361,295	$11,668,736	$641,437	$466,623	($763,931)	($1,245,634)	$134,458	($767,047)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$12,338,543**	**$466,018**	**$15,210,867**	**$774,464**	**$605,485**	**($995,828)**	**($1,569,886)**	**$175,274**	**($1,010,491)**
270 Cook Coal Terminal	$1,293,965	$79,393	$1,595,190	$9,499	$59,418	($104,434)	($67,747)	$18,381	($84,883)
AEP Generating Company	**$1,293,965**	**$79,393**	**$1,595,190**	**$9,499**	**$59,418**	**($104,434)**	**($67,747)**	**$18,381**	**($84,883)**
104 Cardinal Operating Company	$22,103,467	$1,698,577	$27,248,994	$222,482	$1,009,861	($1,783,942)	($1,116,823)	$313,988	($1,354,434)
181 Ohio Power Co. - Generation	$108,456,596	$9,188,959	$133,704,509	$483,610	$4,906,728	($8,753,389)	($4,359,566)	$1,540,666	($6,181,951)
AEP Generation Resources - FERC	**$130,560,063**	**$10,887,536**	**$160,953,503**	**$706,092**	**$5,916,589**	**($10,537,331)**	**($5,476,389)**	**$1,854,654**	**($7,536,385)**
290 Conesville Coal Preparation Company	$1,337,357	$127,251	$1,648,683	$0	$59,900	($107,936)	($51,555)	$18,998	($80,593)
AEP Generation Resources - SEC	**$131,897,419**	**$11,014,787**	**$162,602,186**	**$706,092**	**$5,976,489**	**($10,645,267)**	**($5,527,944)**	**$1,873,652**	**($7,616,978)**
Total	**$1,361,155,680**	**$102,698,063**	**$1,678,022,909**	**$12,916,313**	**$62,195,689**	**($109,857,082)**	**($69,056,806)**	**$19,335,717**	**($84,466,169)**

Location	ASC 715-60 Cost 2014	Estimated Net Periodic Postretirement Benefit Cost 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
140 Appalachian Power Co. - Distribution	($6,831,734)	($7,160,322)	($6,953,083)	($7,190,415)	($7,432,114)	($7,669,296)	($7,848,932)	($8,030,848)	($8,211,434)	($7,767,997)	($4,231,158)
215 Appalachian Power Co. - Generation	($5,560,936)	($5,835,157)	($5,668,397)	($5,871,744)	($6,079,187)	($6,279,243)	($6,435,165)	($6,597,326)	($6,767,883)	($6,392,552)	($3,572,131)
150 Appalachian Power Co. - Transmission	($1,023,167)	($1,055,564)	($1,034,159)	($1,064,634)	($1,097,510)	($1,128,312)	($1,155,781)	($1,185,639)	($1,216,839)	($1,150,830)	($611,977)
Appalachian Power Co. - FERC	**($13,415,837)**	**($14,051,043)**	**($13,655,639)**	**($14,126,793)**	**($14,608,811)**	**($15,076,851)**	**($15,439,878)**	**($15,813,813)**	**($16,196,156)**	**($15,311,379)**	**($8,415,266)**
225 Cedar Coal Co	($30,160)	($31,210)	($28,136)	($28,136)	($28,229)	($28,131)	($27,538)	($26,916)	($26,220)	($22,030)	($16,567)
Appalachian Power Co. - SEC	**($13,445,997)**	**($14,082,253)**	**($13,683,775)**	**($14,154,929)**	**($14,637,040)**	**($15,104,982)**	**($15,467,416)**	**($15,840,729)**	**($16,222,376)**	**($15,333,409)**	**($8,431,833)**
211 AEP Texas Central Company - Distribution	($4,982,625)	($5,228,212)	($5,093,336)	($5,274,070)	($5,457,580)	($5,647,779)	($5,792,251)	($5,944,741)	($6,097,907)	($5,778,047)	($3,100,098)
147 AEP Texas Central Company - Generation	($15,337)	($15,337)	($15,337)	($15,337)	($15,337)	($15,337)	($15,337)	($15,337)	($15,337)	($9,150)	($170)
169 AEP Texas Central Company - Transmission	($474,618)	($498,386)	($487,673)	($506,032)	($523,750)	($542,771)	($557,516)	($572,128)	($587,853)	($558,223)	($288,842)
AEP Texas Central Co.	**($5,472,580)**	**($5,741,935)**	**($5,596,346)**	**($5,795,439)**	**($5,996,667)**	**($6,205,887)**	**($6,365,104)**	**($6,532,206)**	**($6,701,097)**	**($6,345,420)**	**($3,389,110)**
170 Indiana Michigan Power Co. - Distribution	($3,428,479)	($3,589,382)	($3,479,937)	($3,587,004)	($3,697,375)	($3,807,400)	($3,882,688)	($3,961,492)	($4,041,957)	($3,783,332)	($1,985,592)
132 Indiana Michigan Power Co. - Generation	($2,229,986)	($2,335,093)	($2,288,120)	($2,363,197)	($2,438,320)	($2,512,936)	($2,570,357)	($2,629,080)	($2,681,774)	($2,528,167)	($1,227,430)
190 Indiana Michigan Power Co. - Nuclear	($3,641,050)	($3,845,383)	($3,803,964)	($3,945,536)	($4,088,628)	($4,242,654)	($4,364,482)	($4,493,129)	($4,626,121)	($4,385,758)	($1,926,367)
120 Indiana Michigan Power Co. - Transmission	($757,637)	($792,547)	($774,766)	($802,662)	($830,822)	($859,301)	($882,587)	($907,331)	($933,795)	($881,797)	($476,476)
280 Ind Mich River Transp Lakin	($865,099)	($914,729)	($902,875)	($936,606)	($972,356)	($1,009,688)	($1,038,228)	($1,067,344)	($1,098,892)	($1,048,275)	($485,525)
Indiana Michigan Power Co. - FERC	**($10,922,251)**	**($11,477,134)**	**($11,249,662)**	**($11,635,005)**	**($12,027,501)**	**($12,431,979)**	**($12,738,342)**	**($13,058,376)**	**($13,382,539)**	**($12,627,329)**	**($6,101,390)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**($10,922,251)**	**($11,477,134)**	**($11,249,662)**	**($11,635,005)**	**($12,027,501)**	**($12,431,979)**	**($12,738,342)**	**($13,058,376)**	**($13,382,539)**	**($12,627,329)**	**($6,101,390)**
110 Kentucky Power Co. - Distribution	($1,495,454)	($1,560,559)	($1,528,050)	($1,577,818)	($1,623,909)	($1,672,146)	($1,710,749)	($1,747,079)	($1,782,346)	($1,689,905)	($838,175)
117 Kentucky Power Co. - Generation	($856,233)	($895,961)	($872,834)	($902,981)	($935,236)	($966,790)	($992,499)	($1,020,047)	($1,045,891)	($996,394)	($579,041)
180 Kentucky Power Co. - Transmission	($218,985)	($225,887)	($222,753)	($228,501)	($233,793)	($239,452)	($244,674)	($249,351)	($255,741)	($243,606)	($102,604)
600 Kentucky Power Co. - Kammer Actives	($24,378)	($31,705)	($32,843)	($38,110)	($43,267)	($47,797)	($51,881)	($55,013)	($57,386)	($60,453)	($33,303)
701 Kentucky Power Co. - Mitchell Actives	($63,417)	($99,395)	($106,097)	($132,501)	($160,289)	($187,282)	($206,264)	($227,263)	($246,529)	($263,186)	($184,775)
702 Kentucky Power Co. - Mitchell Inactives	($381,868)	($395,969)	($375,128)	($384,402)	($393,921)	($407,186)	($417,356)	($429,896)	($441,688)	($454,381)	($375,259)
Kentucky Power Co.	**($3,040,335)**	**($3,209,476)**	**($3,137,705)**	**($3,264,313)**	**($3,390,415)**	**($3,520,653)**	**($3,623,423)**	**($3,728,649)**	**($3,829,581)**	**($3,707,925)**	**($2,113,157)**
250 Ohio Power Co. - Distribution	($8,015,896)	($8,432,549)	($8,177,533)	($8,481,462)	($8,795,246)	($9,107,607)	($9,336,647)	($9,574,931)	($9,818,776)	($9,287,682)	($5,259,750)
160 Ohio Power Co. - Transmission	($1,419,105)	($1,459,569)	($1,419,173)	($1,453,206)	($1,490,742)	($1,529,789)	($1,558,533)	($1,589,149)	($1,622,856)	($1,518,645)	($804,201)
Ohio Power Co.	**($9,435,001)**	**($9,892,118)**	**($9,596,706)**	**($9,934,668)**	**($10,285,988)**	**($10,637,396)**	**($10,895,180)**	**($11,164,080)**	**($11,441,632)**	**($10,806,327)**	**($6,063,951)**
167 Public Service Co. of Oklahoma - Distribution	($3,024,430)	($3,179,013)	($3,104,714)	($3,216,027)	($3,330,544)	($3,452,636)	($3,544,894)	($3,636,660)	($3,737,027)	($3,543,426)	($1,833,386)
198 Public Service Co. of Oklahoma - Generation	($1,673,794)	($1,757,315)	($1,728,951)	($1,785,952)	($1,846,974)	($1,909,828)	($1,958,125)	($2,004,773)	($2,056,202)	($1,954,335)	($896,813)
114 Public Service Co. of Oklahoma - Transmission	($369,611)	($386,253)	($378,009)	($390,489)	($404,298)	($417,752)	($429,312)	($440,477)	($452,426)	($428,918)	($212,342)
Public Service Co. of Oklahoma	**($5,067,835)**	**($5,322,581)**	**($5,211,674)**	**($5,392,468)**	**($5,581,816)**	**($5,780,216)**	**($5,932,331)**	**($6,081,910)**	**($6,245,655)**	**($5,926,679)**	**($2,942,541)**
159 Southwestern Electric Power Co. - Distribution	($2,116,990)	($2,228,303)	($2,183,265)	($2,267,710)	($2,354,364)	($2,444,717)	($2,514,856)	($2,589,494)	($2,663,055)	($2,656,243)	($1,353,319)
168 Southwestern Electric Power Co. - Generation	($2,361,521)	($2,478,927)	($2,442,168)	($2,525,554)	($2,611,107)	($2,694,808)	($2,764,517)	($2,836,778)	($2,905,414)	($2,765,618)	($1,259,574)
161 Southwestern Electric Power Co. - Texas - Distribution	($1,111,713)	($1,163,084)	($1,141,245)	($1,178,133)	($1,218,314)	($1,257,304)	($1,290,155)	($1,323,053)	($1,360,088)	($1,297,503)	($638,009)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	($343,097)	($358,542)	($351,136)	($363,886)	($376,205)	($389,598)	($401,206)	($412,997)	($425,878)	($405,253)	($214,765)
Southwestern Electric Power Co.	**($5,933,321)**	**($6,228,856)**	**($6,117,814)**	**($6,335,283)**	**($6,559,990)**	**($6,786,427)**	**($6,970,734)**	**($7,162,322)**	**($7,354,435)**	**($7,124,617)**	**($3,465,667)**
119 AEP Texas North Company - Distribution	($1,559,115)	($1,631,883)	($1,598,573)	($1,653,792)	($1,704,697)	($1,758,334)	($1,799,313)	($1,840,259)	($1,882,874)	($1,784,135)	($885,815)
166 AEP Texas North Company - Generation	($211,038)	($223,978)	($210,184)	($220,869)	($231,467)	($241,887)	($248,347)	($255,143)	($261,114)	($237,308)	($202,248)
192 AEP Texas North Company - Transmission	($254,838)	($265,809)	($263,047)	($270,990)	($278,478)	($286,374)	($292,207)	($297,918)	($303,721)	($286,017)	($118,526)
AEP Texas North Co.	**($2,024,991)**	**($2,121,670)**	**($2,071,804)**	**($2,145,651)**	**($2,214,642)**	**($2,286,595)**	**($2,339,867)**	**($2,393,320)**	**($2,447,709)**	**($2,307,460)**	**($1,206,589)**
230 Kingsport Power Co. - Distribution	($235,194)	($248,030)	($240,693)	($250,493)	($260,647)	($270,064)	($278,464)	($287,240)	($295,981)	($281,518)	($163,022)
260 Kingsport Power Co. - Transmission	($49,965)	($51,420)	($50,696)	($51,894)	($52,828)	($54,352)	($55,504)	($56,830)	($58,186)	($54,010)	($26,084)
Kingsport Power Co.	**($285,159)**	**($299,450)**	**($291,389)**	**($302,387)**	**($313,475)**	**($324,416)**	**($333,968)**	**($344,070)**	**($354,167)**	**($335,528)**	**($189,106)**
210 Wheeling Power Co. - Distribution	($350,598)	($366,189)	($354,923)	($366,659)	($378,751)	($392,161)	($401,427)	($410,488)	($419,647)	($395,371)	($214,093)
200 Wheeling Power Co. - Transmission	($10,925)	($11,408)	($10,303)	($10,468)	($10,511)	($10,467)	($10,192)	($9,848)	($9,440)	($7,861)	($5,857)
Wheeling Power Co.	**($361,523)**	**($377,597)**	**($365,226)**	**($377,127)**	**($389,262)**	**($402,628)**	**($411,619)**	**($420,336)**	**($429,087)**	**($403,232)**	**($219,950)**
103 American Electric Power Service Corporation	($19,764,824)	($20,824,114)	($20,458,333)	($21,224,455)	($22,008,776)	($22,817,462)	($23,473,074)	($24,159,739)	($24,899,804)	($23,504,059)	($11,856,560)
American Electric Power Service Corporation	**($19,764,824)**	**($20,824,114)**	**($20,458,333)**	**($21,224,455)**	**($22,008,776)**	**($22,817,462)**	**($23,473,074)**	**($24,159,739)**	**($24,899,804)**	**($23,504,059)**	**($11,856,560)**
143 AEP Pro Serv, Inc.	($4,323)	($4,662)	($4,252)	($4,320)	($4,057)	($4,170)	($3,920)	($4,218)	($4,544)	($4,420)	($4,125)
171 CSW Energy, Inc.	($14,090)	($20,980)	($22,419)	($27,411)	($33,215)	($39,774)	($45,558)	($52,526)	($60,390)	($64,066)	($39,051)
293 Elmwood	($225,031)	($236,767)	($237,950)	($245,336)	($253,277)	($261,821)	($269,313)	($277,263)	($285,637)	($276,620)	($76,973)
292 AEP River Operations LLC	($767,047)	($843,039)	($857,206)	($901,928)	($955,278)	($1,013,658)	($1,066,830)	($1,127,338)	($1,193,450)	($1,173,653)	($322,118)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**($1,010,491)**	**($1,105,448)**	**($1,121,827)**	**($1,178,995)**	**($1,245,827)**	**($1,319,423)**	**($1,385,621)**	**($1,461,345)**	**($1,544,021)**	**($1,518,759)**	**($442,267)**
270 Cook Coal Terminal	($84,883)	($89,379)	($87,831)	($90,821)	($93,985)	($96,617)	($98,284)	($99,896)	($101,546)	($96,066)	($48,894)
AEP Generating Company	**($84,883)**	**($89,379)**	**($87,831)**	**($90,821)**	**($93,985)**	**($96,617)**	**($98,284)**	**($99,896)**	**($101,546)**	**($96,066)**	**($48,894)**
104 Cardinal Operating Company	($1,354,434)	($1,422,724)	($1,391,834)	($1,440,665)	($1,493,705)	($1,546,794)	($1,590,262)	($1,634,731)	($1,679,120)	($1,590,868)	($824,772)
181 Ohio Power Co. - Generation	($6,181,951)	($6,463,199)	($6,256,801)	($6,451,291)	($6,659,187)	($6,863,303)	($7,012,450)	($7,174,269)	($7,344,163)	($6,847,135)	($3,809,345)
AEP Generation Resources - FERC	**($7,536,385)**	**($7,885,923)**	**($7,648,635)**	**($7,891,956)**	**($8,152,892)**	**($8,410,097)**	**($8,602,712)**	**($8,809,000)**	**($9,023,283)**	**($8,438,003)**	**($4,634,117)**
290 Conesville Coal Preparation Company	($80,593)	($83,489)	($79,996)	($81,902)	($84,141)	($85,892)	($86,665)	($87,542)	($87,519)	($81,284)	($44,418)
AEP Generation Resources - SEC	**($7,616,978)**	**($7,969,412)**	**($7,728,631)**	**($7,973,858)**	**($8,237,033)**	**($8,495,989)**	**($8,689,377)**	**($8,896,542)**	**($9,110,802)**	**($8,519,287)**	**($4,678,535)**
Total	**($84,466,169)**	**($88,741,423)**	**($86,718,723)**	**($89,805,399)**	**($92,982,417)**	**($96,210,670)**	**($98,724,340)**	**($101,343,520)**	**($104,064,451)**	**($98,556,097)**	**($51,149,550)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2015 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$110,617,122	$9,853,462	$145,857,646	$723,413	$5,643,303	($9,542,264)	($5,097,397)	$1,112,623	($7,160,322)
215 Appalachian Power Co. - Generation	$91,313,780	$7,962,119	$120,404,624	$622,021	$4,664,325	($7,877,082)	($4,162,884)	$918,463	($5,835,157)
150 Appalachian Power Co. - Transmission	$12,310,346	$928,473	$16,232,190	$34,121	$629,970	($1,061,938)	($781,538)	$123,821	($1,055,564)
Appalachian Power Co. - FERC	**$214,241,248**	**$18,744,054**	**$282,494,460**	**$1,379,555**	**$10,937,598**	**($18,481,284)**	**($10,041,819)**	**$2,154,907**	**($14,051,043)**
225 Cedar Coal Co	$848,950	$126,428	$1,119,409	$0	$41,687	($73,234)	($8,202)	$8,539	($31,210)
Appalachian Power Co. - SEC	**$215,090,198**	**$18,870,482**	**$283,613,869**	**$1,379,555**	**$10,979,285**	**($18,554,518)**	**($10,050,021)**	**$2,163,446**	**($14,082,253)**
211 AEP Texas Central Company - Distribution	$78,331,205	$6,646,444	$103,286,046	$611,978	$4,010,132	($6,757,155)	($3,881,048)	$787,881	($5,228,212)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$7,139,895	$567,986	$9,414,531	$70,349	$367,286	($615,915)	($391,921)	$71,815	($498,386)
AEP Texas Central Co.	**$85,471,100**	**$7,214,430**	**$112,700,577**	**$682,327**	**$4,377,418**	**($7,373,070)**	**($4,288,306)**	**$859,696**	**($5,741,935)**
170 Indiana Michigan Power Co. - Distribution	$54,870,835	$5,229,767	$72,351,646	$400,916	$2,792,603	($4,733,372)	($2,601,438)	$551,909	($3,589,382)
132 Indiana Michigan Power Co. - Generation	$31,196,199	$2,543,957	$41,134,718	$290,059	$1,602,227	($2,691,106)	($1,850,054)	$313,781	($2,335,093)
190 Indiana Michigan Power Co. - Nuclear	$48,870,680	$3,487,742	$64,439,955	$894,255	$2,546,310	($4,215,775)	($3,561,730)	$491,557	($3,845,383)
120 Indiana Michigan Power Co. - Transmission	$11,127,233	$875,796	$14,672,159	$81,093	$571,132	($959,878)	($596,815)	$111,921	($792,547)
280 Ind Mich River Transp Lakin	$12,082,469	$867,433	$15,931,715	$189,573	$627,728	($1,042,281)	($811,278)	$121,529	($914,729)
Indiana Michigan Power Co. - FERC	**$158,147,416**	**$13,004,695**	**$208,530,193**	**$1,855,896**	**$8,140,000**	**($13,642,412)**	**($9,421,315)**	**$1,590,697**	**($11,477,134)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$158,147,416**	**$13,004,695**	**$208,530,193**	**$1,855,896**	**$8,140,000**	**($13,642,412)**	**($9,421,315)**	**$1,590,697**	**($11,477,134)**
110 Kentucky Power Co. - Distribution	$20,208,086	$1,644,944	$26,646,000	$153,834	$1,036,154	($1,743,228)	($1,210,578)	$203,259	($1,560,559)
117 Kentucky Power Co. - Generation	$13,536,148	$1,092,363	$17,848,509	$55,608	$691,789	($1,167,681)	($611,828)	$136,151	($895,961)
180 Kentucky Power Co. - Transmission	$1,934,788	$148,030	$2,551,175	$19,974	$99,730	($166,902)	($198,150)	$19,461	($225,887)
600 Kentucky Power Co. - Kammer Actives	$1,142,816	$32,958	$1,506,896	$36,284	$61,630	($98,584)	($42,530)	$11,495	($31,705)
701 Kentucky Power Co. - Mitchell Actives	$5,598,307	$122,328	$7,381,822	$184,695	$303,299	($482,932)	($160,767)	$56,310	($99,395)
702 Kentucky Power Co. - Mitchell Inactives	$7,476,446	$830,781	$9,858,300	$0	$374,520	($644,947)	($200,743)	$75,201	($395,969)
Kentucky Power Co.	**$49,896,591**	**$3,871,404**	**$65,792,702**	**$450,395**	**$2,567,122**	**($4,304,274)**	**($2,424,596)**	**$501,877**	**($3,209,476)**
250 Ohio Power Co. - Distribution	$139,704,206	$12,284,607	$184,211,326	$970,245	$7,134,407	($12,051,429)	($5,890,962)	$1,405,190	($8,432,549)
160 Ohio Power Co. - Transmission	$17,016,730	$1,562,641	$22,437,939	$7,347	$861,401	($1,467,929)	($1,031,548)	$171,160	($1,459,569)
Ohio Power Co.	**$156,720,936**	**$13,847,248**	**$206,649,265**	**$977,592**	**$7,995,808**	**($13,519,358)**	**($6,922,510)**	**$1,576,350**	**($9,892,118)**
167 Public Service Co. of Oklahoma - Distribution	$46,346,738	$3,849,561	$61,111,933	$450,945	$2,379,581	($3,998,050)	($2,477,659)	$466,170	($3,179,013)
198 Public Service Co. of Oklahoma - Generation	$22,288,399	$1,732,820	$29,389,062	$288,574	$1,151,253	($1,922,684)	($1,498,642)	$224,184	($1,757,315)
114 Public Service Co. of Oklahoma - Transmission	$5,374,416	$451,500	$7,086,603	$60,420	$276,236	($463,618)	($313,349)	$54,058	($386,253)
Public Service Co. of Oklahoma	**$74,009,553**	**$6,033,881**	**$97,587,598**	**$799,939**	**$3,807,070**	**($6,384,352)**	**($4,289,650)**	**$744,412**	**($5,322,581)**
159 Southwestern Electric Power Co. - Distribution	$31,745,259	$2,445,600	$41,858,699	$348,814	$1,637,014	($2,738,470)	($1,794,965)	$319,304	($2,228,303)
168 Southwestern Electric Power Co. - Generation	$31,092,263	$2,351,859	$40,997,670	$419,561	$1,608,607	($2,682,140)	($2,137,691)	$312,736	($2,478,927)
161 Southwestern Electric Power Co. - Texas - Distribution	$15,005,301	$1,186,934	$19,785,706	$150,850	$772,228	($1,294,416)	($942,674)	$150,928	($1,163,084)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,992,012	$389,895	$6,582,373	$45,303	$256,779	($430,630)	($280,205)	$50,211	($358,542)
Southwestern Electric Power Co.	**$82,834,835**	**$6,374,288**	**$109,224,448**	**$964,528**	**$4,274,628**	**($7,145,656)**	**($5,155,535)**	**$833,179**	**($6,228,856)**
119 AEP Texas North Company - Distribution	$21,879,000	$1,752,359	$28,849,236	$187,766	$1,123,701	($1,887,368)	($1,276,048)	$220,066	($1,631,883)
166 AEP Texas North Company - Generation	$6,082,216	$579,551	$8,019,895	$0	$307,198	($524,676)	($67,677)	$61,177	($223,978)
192 AEP Texas North Company - Transmission	$2,800,194	$196,483	$3,692,283	$36,235	$145,191	($241,556)	($233,844)	$28,165	($265,809)
AEP Texas North Co.	**$30,761,410**	**$2,528,393**	**$40,561,414**	**$224,001**	**$1,576,090**	**($2,653,600)**	**($1,577,569)**	**$309,408**	**($2,121,670)**
230 Kingsport Power Co. - Distribution	$4,301,366	$369,851	$5,671,700	$36,907	$220,254	($371,053)	($177,403)	$43,265	($248,030)
260 Kingsport Power Co. - Transmission	$531,282	$40,011	$700,538	$2,254	$27,231	($45,830)	($40,419)	$5,344	($51,420)
Kingsport Power Co.	**$4,832,648**	**$409,862**	**$6,372,238**	**$39,161**	**$247,485**	**($416,883)**	**($217,822)**	**$48,609**	**($299,450)**
210 Wheeling Power Co. - Distribution	$5,643,580	$516,137	$7,441,518	$35,466	$287,488	($486,837)	($259,071)	$56,765	($366,189)
200 Wheeling Power Co. - Transmission	$327,351	$45,815	$431,639	$0	$16,151	($28,239)	($2,613)	$3,293	($11,408)
Wheeling Power Co.	**$5,970,931**	**$561,952**	**$7,873,157**	**$35,466**	**$303,639**	**($515,076)**	**($261,684)**	**$60,058**	**($377,597)**
103 American Electric Power Service Corporation	$286,210,613	$21,619,572	$377,391,904	$3,480,829	$14,788,122	($24,689,642)	($17,282,221)	$2,878,798	($20,824,114)
American Electric Power Service Corporation	**$286,210,613**	**$21,619,572**	**$377,391,904**	**$3,480,829**	**$14,788,122**	**($24,689,642)**	**($17,282,221)**	**$2,878,798**	**($20,824,114)**
143 AEP Pro Serv, Inc.	$131,188	$18,558	$172,982	$0	$6,468	($11,317)	($1,133)	$1,320	($4,662)
171 CSW Energy, Inc.	$978,895	$20,075	$1,290,752	$46,831	$53,838	($84,443)	($47,052)	$9,846	($20,980)
293 Elmwood	$1,824,382	$97,524	$2,405,596	$79,949	$98,379	($157,378)	($276,067)	$18,350	($236,767)
292 AEP River Operations LLC	$9,856,165	$474,094	$12,996,153	$611,315	$542,375	($850,231)	($1,245,634)	$99,136	($843,039)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$12,790,630**	**$610,251**	**$16,865,483**	**$738,095**	**$701,060**	**($1,103,369)**	**($1,569,886)**	**$128,652**	**($1,105,448)**
270 Cook Coal Terminal	$1,238,760	$92,487	$1,633,406	$9,053	$63,715	($106,860)	($67,747)	$12,460	($89,379)
AEP Generating Company	**$1,238,760**	**$92,487**	**$1,633,406**	**$9,053**	**$63,715**	**($106,860)**	**($67,747)**	**$12,460**	**($89,379)**
104 Cardinal Operating Company	$20,883,184	$1,703,746	$27,536,172	$212,034	$1,073,480	($1,801,465)	($1,116,823)	$210,050	($1,422,724)
181 Ohio Power Co. - Generation	$101,010,685	$9,364,299	$133,190,780	$460,900	$5,133,044	($8,713,575)	($4,359,566)	$1,015,998	($6,463,199)
AEP Generation Resources - FERC	**$121,893,869**	**$11,068,045**	**$160,726,952**	**$672,934**	**$6,206,524**	**($10,515,040)**	**($5,476,389)**	**$1,226,048**	**($7,885,923)**
290 Conesville Coal Preparation Company	$1,225,747	$133,387	$1,616,247	$0	$61,475	($105,738)	($51,555)	$12,329	($83,489)
AEP Generation Resources - SEC	**$123,119,616**	**$11,201,432**	**$162,343,199**	**$672,934**	**$6,267,999**	**($10,620,778)**	**($5,527,944)**	**$1,238,377**	**($7,969,412)**
Total	**$1,287,095,237**	**$106,240,377**	**$1,697,139,453**	**$12,309,771**	**$66,089,441**	**($111,029,848)**	**($69,056,806)**	**$12,946,019**	**($88,741,423)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2016 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$108,559,870	$9,861,383	$144,790,705	$708,970	$5,742,228	($9,468,358)	($5,097,397)	$1,161,474	($6,953,083)
215 Appalachian Power Co. - Generation	$89,820,748	$7,953,644	$119,797,577	$609,602	$4,757,872	($7,833,972)	($4,162,884)	$960,985	($5,668,397)
150 Appalachian Power Co. - Transmission	$12,206,699	$929,744	$16,280,570	$33,440	$647,982	($1,064,642)	($781,538)	$130,599	($1,034,159)
Appalachian Power Co. - FERC	**$210,587,317**	**$18,744,771**	**$280,868,852**	**$1,352,012**	**$11,148,082**	**($18,366,972)**	**($10,041,819)**	**$2,253,058**	**($13,655,639)**
225 Cedar Coal Co	$774,406	$120,512	$1,032,857	$0	$39,323	($67,542)	($8,202)	$8,285	($28,136)
Appalachian Power Co. - SEC	**$211,361,723**	**$18,865,283**	**$281,901,709**	**$1,352,012**	**$11,187,405**	**($18,434,514)**	**($10,050,021)**	**$2,261,343**	**($13,683,775)**
211 AEP Texas Central Company - Distribution	$77,325,072	$6,674,148	$103,131,587	$599,760	$4,104,783	($6,744,126)	($3,881,048)	$827,295	($5,093,336)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$7,103,076	$576,321	$9,473,661	$68,944	$378,824	($619,515)	($391,921)	$75,995	($487,673)
AEP Texas Central Co.	**$84,428,148**	**$7,250,469**	**$112,605,248**	**$668,704**	**$4,483,607**	**($7,363,641)**	**($4,288,306)**	**$903,290**	**($5,596,346)**
170 Indiana Michigan Power Co. - Distribution	$53,539,585	$5,193,425	$71,407,918	$392,912	$2,825,380	($4,669,607)	($2,601,438)	$572,816	($3,479,937)
132 Indiana Michigan Power Co. - Generation	$30,952,099	$2,650,515	$41,282,071	$284,268	$1,646,087	($2,699,575)	($1,850,054)	$331,154	($2,288,120)
190 Indiana Michigan Power Co. - Nuclear	$49,474,980	$3,766,355	$65,986,789	$876,401	$2,667,137	($4,315,101)	($3,561,730)	$529,329	($3,803,964)
120 Indiana Michigan Power Co. - Transmission	$11,049,155	$885,702	$14,736,706	$79,474	$588,044	($963,683)	($596,815)	$118,214	($774,766)
280 Ind Mich River Transp Lakin	$12,192,891	$929,721	$16,262,154	$185,788	$655,602	($1,063,438)	($811,278)	$130,451	($902,875)
Indiana Michigan Power Co. - FERC	**$157,208,710**	**$13,425,718**	**$209,675,638**	**$1,818,843**	**$8,382,250**	**($13,711,404)**	**($9,421,315)**	**$1,681,964**	**($11,249,662)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$157,208,710**	**$13,425,718**	**$209,675,638**	**$1,818,843**	**$8,382,250**	**($13,711,404)**	**($9,421,315)**	**$1,681,964**	**($11,249,662)**
110 Kentucky Power Co. - Distribution	$20,016,706	$1,687,631	$26,697,093	$150,763	$1,063,422	($1,745,814)	($1,210,578)	$214,157	($1,528,050)
117 Kentucky Power Co. - Generation	$13,367,199	$1,137,181	$17,828,376	$54,498	$707,339	($1,165,858)	($611,828)	$143,015	($872,834)
180 Kentucky Power Co. - Transmission	$1,931,901	$135,711	$2,576,655	$19,575	$103,649	($168,496)	($198,150)	$20,669	($222,753)
600 Kentucky Power Co. - Kammer Actives	$1,223,888	$54,992	$1,632,349	$35,560	$67,778	($106,745)	($42,530)	$13,094	($32,843)
701 Kentucky Power Co. - Mitchell Actives	$6,043,553	$230,079	$8,060,532	$181,008	$336,108	($527,106)	($160,767)	$64,660	($106,097)
702 Kentucky Power Co. - Mitchell Inactives	$7,113,859	$785,172	$9,488,042	$0	$369,959	($620,455)	($200,743)	$76,111	($375,128)
Kentucky Power Co.	**$49,697,106**	**$4,030,766**	**$66,283,047**	**$441,404**	**$2,648,255**	**($4,334,474)**	**($2,424,596)**	**$531,706**	**($3,137,705)**
250 Ohio Power Co. - Distribution	$137,332,619	$12,328,388	$183,166,088	$950,874	$7,271,099	($11,977,855)	($5,890,962)	$1,469,311	($8,177,533)
160 Ohio Power Co. - Transmission	$16,540,641	$1,447,885	$22,060,924	$7,200	$870,847	($1,442,639)	($1,031,548)	$176,967	($1,419,173)
Ohio Power Co.	**$153,873,260**	**$13,776,273**	**$205,227,012**	**$958,074**	**$8,141,946**	**($13,420,494)**	**($6,922,510)**	**$1,646,278**	**($9,596,706)**
167 Public Service Co. of Oklahoma - Distribution	$45,932,533	$3,865,742	$61,262,084	$441,942	$2,445,711	($4,006,137)	($2,477,659)	$491,429	($3,104,714)
198 Public Service Co. of Oklahoma - Generation	$22,288,902	$1,807,587	$29,727,613	$282,813	$1,192,401	($1,943,990)	($1,498,642)	$238,467	($1,728,951)
114 Public Service Co. of Oklahoma - Transmission	$5,329,753	$458,519	$7,108,508	$59,214	$283,953	($464,850)	($313,349)	$57,023	($378,009)
Public Service Co. of Oklahoma	**$73,551,188**	**$6,131,848**	**$98,098,205**	**$783,969**	**$3,922,065**	**($6,414,977)**	**($4,289,650)**	**$786,919**	**($5,211,674)**
159 Southwestern Electric Power Co. - Distribution	$31,702,945	$2,459,743	$42,283,505	$341,850	$1,695,726	($2,765,063)	($1,794,965)	$339,187	($2,183,265)
168 Southwestern Electric Power Co. - Generation	$31,179,133	$2,481,738	$41,584,875	$411,184	$1,670,133	($2,719,377)	($2,137,691)	$333,583	($2,442,168)
161 Southwestern Electric Power Co. - Texas - Distribution	$14,938,148	$1,219,506	$19,923,614	$147,838	$796,642	($1,302,873)	($942,674)	$159,822	($1,141,245)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,969,638	$399,189	$6,628,208	$44,399	$264,941	($433,441)	($280,205)	$53,170	($351,136)
Southwestern Electric Power Co.	**$82,789,864**	**$6,560,176**	**$110,420,202**	**$945,271**	**$4,427,442**	**($7,220,754)**	**($5,155,535)**	**$885,762**	**($6,117,814)**
119 AEP Texas North Company - Distribution	$21,724,167	$1,812,715	$28,974,403	$184,017	$1,155,768	($1,894,735)	($1,276,048)	$232,425	($1,598,573)
166 AEP Texas North Company - Generation	$5,887,387	$582,992	$7,852,247	$0	$307,989	($513,485)	($67,677)	$62,989	($210,184)
192 AEP Texas North Company - Transmission	$2,822,300	$218,754	$3,764,216	$35,512	$151,244	($246,155)	($233,844)	$30,196	($263,047)
AEP Texas North Co.	**$30,433,854**	**$2,614,461**	**$40,590,866**	**$219,529**	**$1,615,001**	**($2,654,375)**	**($1,577,569)**	**$325,610**	**($2,071,804)**
230 Kingsport Power Co. - Distribution	$4,244,568	$372,642	$5,661,153	$36,170	$225,330	($370,202)	($177,403)	$45,412	($240,693)
260 Kingsport Power Co. - Transmission	$527,705	$46,153	$703,822	$2,209	$27,893	($46,025)	($40,419)	$5,646	($50,696)
Kingsport Power Co.	**$4,772,273**	**$418,795**	**$6,364,975**	**$38,379**	**$253,223**	**($416,227)**	**($217,822)**	**$51,058**	**($291,389)**
210 Wheeling Power Co. - Distribution	$5,523,124	$503,800	$7,366,415	$34,758	$292,014	($481,715)	($259,071)	$59,091	($354,923)
200 Wheeling Power Co. - Transmission	$301,659	$44,160	$402,335	$0	$15,393	($26,310)	($2,613)	$3,227	($10,303)
Wheeling Power Co.	**$5,824,783**	**$547,960**	**$7,768,750**	**$34,758**	**$307,407**	**($508,025)**	**($261,684)**	**$62,318**	**($365,226)**
103 American Electric Power Service Corporation	$286,634,336	$22,372,343	$382,295,848	$3,411,334	$15,345,507	($24,999,629)	($17,282,221)	$3,066,676	($20,458,333)
American Electric Power Service Corporation	**$286,634,336**	**$22,372,343**	**$382,295,848**	**$3,411,334**	**$15,345,507**	**($24,999,629)**	**($17,282,221)**	**$3,066,676**	**($20,458,333)**
143 AEP Pro Serv, Inc.	$120,687	$19,215	$160,965	$0	$6,116	($10,526)	($1,133)	$1,291	($4,252)
171 CSW Energy, Inc.	$1,073,626	$25,252	$1,431,939	$45,896	$60,889	($93,639)	($47,052)	$11,487	($22,419)
293 Elmwood	$1,930,608	$110,594	$2,574,930	$78,353	$107,492	($168,383)	($276,067)	$20,655	($237,950)
292 AEP River Operations LLC	$10,676,345	$511,923	$14,239,475	$599,110	$606,261	($931,168)	($1,245,634)	$114,225	($857,206)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$13,801,266**	**$666,984**	**$18,407,309**	**$723,359**	**$780,758**	**($1,203,716)**	**($1,569,886)**	**$147,658**	**($1,121,827)**
270 Cook Coal Terminal	$1,235,307	$105,460	$1,647,579	$8,872	$65,569	($107,741)	($67,747)	$13,216	($87,831)
AEP Generating Company	**$1,235,307**	**$105,460**	**$1,647,579**	**$8,872**	**$65,569**	**($107,741)**	**($67,747)**	**$13,216**	**($87,831)**
104 Cardinal Operating Company	$20,738,026	$1,768,448	$27,659,147	$207,801	$1,104,039	($1,808,726)	($1,116,823)	$221,875	($1,391,834)
181 Ohio Power Co. - Generation	$98,537,857	$9,337,649	$131,423,939	$451,698	$5,191,077	($8,594,259)	($4,359,566)	$1,054,249	($6,256,801)
AEP Generation Resources - FERC	**$119,275,883**	**$11,106,097**	**$159,083,086**	**$659,499**	**$6,295,116**	**($10,402,985)**	**($5,476,389)**	**$1,276,124**	**($7,648,635)**
290 Conesville Coal Preparation Company	$1,169,231	$120,908	$1,559,451	$0	$61,027	($101,978)	($51,555)	$12,510	($79,996)
AEP Generation Resources - SEC	**$120,445,114**	**$11,227,005**	**$160,642,537**	**$659,499**	**$6,356,143**	**($10,504,963)**	**($5,527,944)**	**$1,288,634**	**($7,728,631)**
Total	**$1,276,056,932**	**$107,993,541**	**$1,701,928,925**	**$12,064,007**	**$67,916,578**	**($111,294,934)**	**($69,056,806)**	**$13,652,432**	**($86,718,723)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2017 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$104,185,460	$9,711,708	$143,668,361	$714,839	$5,606,193	($9,396,317)	($5,097,397)	$982,267	($7,190,415)
215 Appalachian Power Co. - Generation	$86,434,635	$7,885,258	$119,190,550	$614,648	$4,656,980	($7,795,399)	($4,162,884)	$814,911	($5,871,744)
150 Appalachian Power Co. - Transmission	$11,848,718	$916,867	$16,338,997	$33,717	$640,094	($1,068,617)	($781,538)	$111,710	($1,064,634)
Appalachian Power Co. - FERC	**$202,468,813**	**$18,513,833**	**$279,197,908**	**$1,363,204**	**$10,903,267**	**($18,260,333)**	**($10,041,819)**	**$1,908,888**	**($14,126,793)**
225 Cedar Coal Co	$686,860	$105,985	$947,158	$0	$35,537	($61,947)	($8,202)	$6,476	($28,136)
Appalachian Power Co. - SEC	**$203,155,673**	**$18,619,818**	**$280,145,066**	**$1,363,204**	**$10,938,804**	**($18,322,280)**	**($10,050,021)**	**$1,915,364**	**($14,154,929)**
211 AEP Texas Central Company - Distribution	$74,664,455	$6,622,214	$102,959,855	$604,725	$4,032,178	($6,733,866)	($3,881,048)	$703,941	($5,274,070)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$6,910,566	$594,169	$9,529,446	$69,515	$374,474	($623,253)	($391,921)	$65,153	($506,032)
AEP Texas Central Co.	**$81,575,021**	**$7,216,383**	**$112,489,301**	**$674,240**	**$4,406,652**	**($7,357,119)**	**($4,288,306)**	**$769,094**	**($5,795,439)**
170 Indiana Michigan Power Co. - Distribution	$51,091,605	$5,028,179	$70,453,662	$396,164	$2,744,444	($4,607,869)	($2,601,438)	$481,695	($3,587,004)
132 Indiana Michigan Power Co. - Generation	$29,954,711	$2,683,922	$41,306,572	$286,621	$1,619,388	($2,701,567)	($1,850,054)	$282,415	($2,363,197)
190 Indiana Michigan Power Co. - Nuclear	$48,800,519	$3,933,242	$67,294,328	$883,656	$2,673,683	($4,401,239)	($3,561,730)	$460,094	($3,945,536)
120 Indiana Michigan Power Co. - Transmission	$10,731,651	$896,068	$14,798,598	$80,132	$580,712	($967,870)	($596,815)	$101,179	($802,662)
280 Ind Mich River Transp Lakin	$11,993,561	$947,900	$16,538,731	$187,326	$655,950	($1,081,680)	($811,278)	$113,076	($936,606)
Indiana Michigan Power Co. - FERC	**$152,572,047**	**$13,489,311**	**$210,391,891**	**$1,833,899**	**$8,274,177**	**($13,760,225)**	**($9,421,315)**	**$1,438,459**	**($11,635,005)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$152,572,047**	**$13,489,311**	**$210,391,891**	**$1,833,899**	**$8,274,177**	**($13,760,225)**	**($9,421,315)**	**$1,438,459**	**($11,635,005)**
110 Kentucky Power Co. - Distribution	$19,364,048	$1,748,951	$26,702,392	$152,011	$1,044,596	($1,746,412)	($1,210,578)	$182,565	($1,577,818)
117 Kentucky Power Co. - Generation	$12,872,719	$1,102,396	$17,751,061	$54,949	$693,503	($1,160,970)	($611,828)	$121,365	($902,981)
180 Kentucky Power Co. - Transmission	$1,901,813	$148,582	$2,622,538	$19,737	$103,503	($171,521)	($198,150)	$17,930	($228,501)
600 Kentucky Power Co. - Kammer Actives	$1,260,568	$80,716	$1,738,282	$35,854	$70,370	($113,689)	($42,530)	$11,885	($38,110)
701 Kentucky Power Co. - Mitchell Actives	$6,272,538	$331,303	$8,649,626	$182,506	$352,332	($565,710)	($160,767)	$59,138	($132,501)
702 Kentucky Power Co. - Mitchell Inactives	$6,637,219	$699,503	$9,152,509	$0	$352,365	($598,600)	($200,743)	$62,576	($384,402)
Kentucky Power Co.	**$48,308,905**	**$4,111,451**	**$66,616,408**	**$445,057**	**$2,616,669**	**($4,356,902)**	**($2,424,596)**	**$455,459**	**($3,264,313)**
250 Ohio Power Co. - Distribution	$132,004,516	$12,109,969	$182,029,934	$958,745	$7,111,482	($11,905,273)	($5,890,962)	$1,244,546	($8,481,462)
160 Ohio Power Co. - Transmission	$15,824,350	$1,358,100	$21,821,264	$7,260	$849,061	($1,427,172)	($1,031,548)	$149,193	($1,453,206)
Ohio Power Co.	**$147,828,866**	**$13,468,069**	**$203,851,198**	**$966,005**	**$7,960,543**	**($13,332,445)**	**($6,922,510)**	**$1,393,739**	**($9,934,668)**
167 Public Service Co. of Oklahoma - Distribution	$44,542,211	$3,839,529	$61,422,260	$445,600	$2,413,275	($4,017,190)	($2,477,659)	$419,947	($3,216,027)
198 Public Service Co. of Oklahoma - Generation	$21,755,187	$1,801,935	$29,999,695	$285,154	$1,184,492	($1,962,065)	($1,498,642)	$205,109	($1,785,952)
114 Public Service Co. of Oklahoma - Transmission	$5,166,585	$443,940	$7,124,553	$59,704	$280,411	($465,966)	($313,349)	$48,711	($390,489)
Public Service Co. of Oklahoma	**$71,463,983**	**$6,085,404**	**$98,546,508**	**$790,458**	**$3,878,178**	**($6,445,221)**	**($4,289,650)**	**$673,767**	**($5,392,468)**
159 Southwestern Electric Power Co. - Distribution	$30,993,932	$2,509,477	$42,739,624	$344,680	$1,685,654	($2,795,292)	($1,794,965)	$292,213	($2,267,710)
168 Southwestern Electric Power Co. - Generation	$30,496,470	$2,554,983	$42,053,640	$414,588	$1,660,454	($2,750,427)	($2,137,691)	$287,522	($2,525,554)
161 Southwestern Electric Power Co. - Texas - Distribution	$14,528,661	$1,199,710	$20,034,551	$149,062	$788,818	($1,310,316)	($942,674)	$136,977	($1,178,133)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,835,041	$406,924	$6,667,364	$44,767	$262,031	($436,064)	($280,205)	$45,585	($363,886)
Southwestern Electric Power Co.	**$80,854,104**	**$6,671,094**	**$111,495,179**	**$953,097**	**$4,396,957**	**($7,292,099)**	**($5,155,535)**	**$762,297**	**($6,335,283)**
119 AEP Texas North Company - Distribution	$21,056,363	$1,894,113	$29,036,040	$185,540	$1,137,234	($1,899,039)	($1,276,048)	$198,521	($1,653,792)
166 AEP Texas North Company - Generation	$5,560,918	$561,288	$7,668,325	$0	$295,909	($501,530)	($67,677)	$52,429	($220,869)
192 AEP Texas North Company - Transmission	$2,764,715	$235,440	$3,812,452	$35,806	$150,327	($249,345)	($233,844)	$26,066	($270,990)
AEP Texas North Co.	**$29,381,996**	**$2,690,841**	**$40,516,817**	**$221,346**	**$1,583,470**	**($2,649,914)**	**($1,577,569)**	**$277,016**	**($2,145,651)**
230 Kingsport Power Co. - Distribution	$4,095,522	$369,164	$5,647,592	$36,469	$221,196	($369,368)	($177,403)	$38,613	($250,493)
260 Kingsport Power Co. - Transmission	$506,962	$46,132	$699,084	$2,227	$27,240	($45,722)	($40,419)	$4,780	($51,894)
Kingsport Power Co.	**$4,602,484**	**$415,296**	**$6,346,676**	**$38,696**	**$248,436**	**($415,090)**	**($217,822)**	**$43,393**	**($302,387)**
210 Wheeling Power Co. - Distribution	$5,297,072	$486,611	$7,304,490	$35,046	$285,159	($477,734)	($259,071)	$49,941	($366,659)
200 Wheeling Power Co. - Transmission	$270,390	$41,992	$372,859	$0	$13,982	($24,386)	($2,613)	$2,549	($10,468)
Wheeling Power Co.	**$5,567,462**	**$528,603**	**$7,677,349**	**$35,046**	**$299,141**	**($502,120)**	**($261,684)**	**$52,490**	**($377,127)**
103 American Electric Power Service Corporation	$280,423,541	$22,848,712	$386,694,943	$3,439,573	$15,265,289	($25,290,945)	($17,282,221)	$2,643,849	($21,224,455)
American Electric Power Service Corporation	**$280,423,541**	**$22,848,712**	**$386,694,943**	**$3,439,573**	**$15,265,289**	**($25,290,945)**	**($17,282,221)**	**$2,643,849**	**($21,224,455)**
143 AEP Pro Serv, Inc.	$106,601	$19,829	$146,999	$0	$5,422	($9,614)	($1,133)	$1,005	($4,320)
171 CSW Energy, Inc.	$1,144,566	$32,069	$1,578,319	$46,276	$65,801	($103,227)	($47,052)	$10,791	($27,411)
293 Elmwood	$1,987,465	$126,196	$2,740,650	$79,002	$112,237	($179,246)	($276,067)	$18,738	($245,336)
292 AEP River Operations LLC	$11,265,532	$552,272	$15,534,802	$604,069	$649,445	($1,016,020)	($1,245,634)	$106,212	($901,928)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$14,504,164**	**$730,366**	**$20,000,770**	**$729,347**	**$832,905**	**($1,308,107)**	**($1,569,886)**	**$136,746**	**($1,178,995)**
270 Cook Coal Terminal	$1,193,245	$107,702	$1,645,446	$8,945	$64,348	($107,617)	($67,747)	$11,250	($90,821)
AEP Generating Company	**$1,193,245**	**$107,702**	**$1,645,446**	**$8,945**	**$64,348**	**($107,617)**	**($67,747)**	**$11,250**	**($90,821)**
104 Cardinal Operating Company	$20,095,437	$1,720,822	$27,710,954	$209,521	$1,089,551	($1,812,375)	($1,116,823)	$189,461	($1,440,665)
181 Ohio Power Co. - Generation	$93,973,270	$8,901,888	$129,586,083	$455,437	$5,042,150	($8,475,297)	($4,359,566)	$885,985	($6,451,291)
AEP Generation Resources - FERC	**$114,068,707**	**$10,622,710**	**$157,297,037**	**$664,958**	**$6,131,701**	**($10,287,672)**	**($5,476,389)**	**$1,075,446**	**($7,891,956)**
290 Conesville Coal Preparation Company	$1,099,177	$113,376	$1,515,729	$0	$58,423	($99,133)	($51,555)	$10,363	($81,902)
AEP Generation Resources - SEC	**$115,167,884**	**$10,736,086**	**$158,812,766**	**$664,958**	**$6,190,124**	**($10,386,805)**	**($5,527,944)**	**$1,085,809**	**($7,973,858)**
Total	**$1,236,599,375**	**$107,719,136**	**$1,705,230,318**	**$12,163,871**	**$66,955,693**	**($111,526,889)**	**($69,056,806)**	**$11,658,732**	**($89,805,399)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2018 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$99,870,493	$9,594,833	$142,601,118	$720,756	$5,464,038	($9,328,937)	($5,097,397)	$809,426	($7,432,114)
215 Appalachian Power Co. - Generation	$83,052,364	$7,846,191	$118,587,178	$619,736	$4,548,792	($7,757,950)	($4,162,884)	$673,119	($6,079,187)
150 Appalachian Power Co. - Transmission	$11,499,238	$939,799	$16,419,306	$33,996	$630,981	($1,074,148)	($781,538)	$93,199	($1,097,510)
Appalachian Power Co. - FERC	**$194,422,095**	**$18,380,823**	**$277,607,602**	**$1,374,488**	**$10,643,811**	**($18,161,035)**	**($10,041,819)**	**$1,575,744**	**($14,608,811)**
225 Cedar Coal Co	$610,759	$97,468	$872,079	$0	$32,074	($57,051)	($8,202)	$4,950	($28,229)
Appalachian Power Co. - SEC	**$195,032,854**	**$18,478,291**	**$278,479,681**	**$1,374,488**	**$10,675,885**	**($18,218,086)**	**($10,050,021)**	**$1,580,694**	**($14,637,040)**
211 AEP Texas Central Company - Distribution	$72,012,674	$6,499,057	$102,824,043	$609,731	$3,956,821	($6,726,729)	($3,881,048)	$583,645	($5,457,580)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$6,698,393	$580,417	$9,564,370	$70,090	$369,491	($625,699)	($391,921)	$54,289	($523,750)
AEP Texas Central Co.	**$78,711,067**	**$7,079,474**	**$112,388,413**	**$679,821**	**$4,326,312**	**($7,352,428)**	**($4,288,306)**	**$637,934**	**($5,996,667)**
170 Indiana Michigan Power Co. - Distribution	$48,752,832	$4,916,231	$69,612,236	$399,443	$2,663,509	($4,554,019)	($2,601,438)	$395,130	($3,697,375)
132 Indiana Michigan Power Co. - Generation	$28,909,246	$2,684,157	$41,278,366	$288,994	$1,588,861	($2,700,423)	($1,850,054)	$234,302	($2,438,320)
190 Indiana Michigan Power Co. - Nuclear	$47,980,561	$3,932,976	$68,509,541	$890,971	$2,675,141	($4,481,881)	($3,561,730)	$388,871	($4,088,628)
120 Indiana Michigan Power Co. - Transmission	$10,400,174	$890,374	$14,849,996	$80,795	$572,391	($971,484)	($596,815)	$84,291	($830,822)
280 Ind Mich River Transp Lakin	$11,779,915	$970,770	$16,820,074	$188,877	$654,938	($1,100,366)	($811,278)	$95,473	($972,356)
Indiana Michigan Power Co. - FERC	**$147,822,728**	**$13,394,508**	**$211,070,213**	**$1,849,080**	**$8,154,840**	**($13,808,173)**	**($9,421,315)**	**$1,198,067**	**($12,027,501)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$147,822,728**	**$13,394,508**	**$211,070,213**	**$1,849,080**	**$8,154,840**	**($13,808,173)**	**($9,421,315)**	**$1,198,067**	**($12,027,501)**
110 Kentucky Power Co. - Distribution	$18,639,200	$1,698,708	$26,614,175	$153,269	$1,023,428	($1,741,094)	($1,210,578)	$151,066	($1,623,909)
117 Kentucky Power Co. - Generation	$12,403,978	$1,098,290	$17,711,149	$55,404	$679,317	($1,158,660)	($611,828)	$100,531	($935,236)
180 Kentucky Power Co. - Transmission	$1,859,264	$144,127	$2,654,769	$19,900	$103,062	($173,674)	($198,150)	$15,069	($233,793)
600 Kentucky Power Co. - Kammer Actives	$1,274,283	$102,464	$1,819,498	$36,151	$71,815	($119,031)	($42,530)	$10,328	($43,267)
701 Kentucky Power Co. - Mitchell Actives	$6,416,687	$441,190	$9,162,133	$184,017	$363,840	($599,385)	($160,767)	$52,006	($160,289)
702 Kentucky Power Co. - Mitchell Inactives	$6,232,401	$596,531	$8,898,998	$0	$338,481	($582,171)	($200,743)	$50,512	($393,921)
Kentucky Power Co.	**$46,825,813**	**$4,081,310**	**$66,860,722**	**$448,741**	**$2,579,943**	**($4,374,015)**	**($2,424,596)**	**$379,512**	**($3,390,415)**
250 Ohio Power Co. - Distribution	$126,791,334	$11,996,531	$181,040,320	$966,681	$6,945,044	($11,843,622)	($5,890,962)	$1,027,613	($8,795,246)
160 Ohio Power Co. - Transmission	$15,182,063	$1,323,372	$21,677,866	$7,320	$828,601	($1,418,162)	($1,031,548)	$123,047	($1,490,742)
Ohio Power Co.	**$141,973,397**	**$13,319,903**	**$202,718,186**	**$974,001**	**$7,773,645**	**($13,261,784)**	**($6,922,510)**	**$1,150,660**	**($10,285,988)**
167 Public Service Co. of Oklahoma - Distribution	$43,162,096	$3,773,519	$61,629,446	$449,289	$2,379,794	($4,031,786)	($2,477,659)	$349,818	($3,330,544)
198 Public Service Co. of Oklahoma - Generation	$21,226,449	$1,829,081	$30,308,405	$287,514	$1,174,889	($1,982,770)	($1,498,642)	$172,035	($1,846,974)
114 Public Service Co. of Oklahoma - Transmission	$5,016,334	$447,888	$7,162,624	$60,198	$276,774	($468,577)	($313,349)	$40,656	($404,298)
Public Service Co. of Oklahoma	**$69,404,879**	**$6,050,488**	**$99,100,475**	**$797,001**	**$3,831,457**	**($6,483,133)**	**($4,289,650)**	**$562,509**	**($5,581,816)**
159 Southwestern Electric Power Co. - Distribution	$30,234,968	$2,523,465	$43,171,312	$347,533	$1,672,280	($2,824,259)	($1,794,965)	$245,047	($2,354,364)
168 Southwestern Electric Power Co. - Generation	$29,741,277	$2,612,311	$42,466,391	$418,020	$1,645,661	($2,778,143)	($2,137,691)	$241,046	($2,611,107)
161 Southwestern Electric Power Co. - Texas - Distribution	$14,136,004	$1,223,082	$20,184,240	$150,296	$779,944	($1,320,449)	($942,674)	$114,569	($1,218,314)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,691,496	$388,383	$6,698,801	$45,138	$259,073	($438,234)	($280,205)	$38,023	($376,205)
Southwestern Electric Power Co.	**$78,803,745**	**$6,747,241**	**$112,520,744**	**$960,987**	**$4,356,958**	**($7,361,085)**	**($5,155,535)**	**$638,685**	**($6,559,990)**
119 AEP Texas North Company - Distribution	$20,297,176	$1,845,426	$28,981,533	$187,076	$1,115,737	($1,895,966)	($1,276,048)	$164,504	($1,704,697)
166 AEP Texas North Company - Generation	$5,246,979	$543,352	$7,491,953	$0	$283,807	($490,122)	($67,677)	$42,525	($231,467)
192 AEP Texas North Company - Transmission	$2,690,508	$236,187	$3,841,670	$36,102	$148,779	($251,321)	($233,844)	$21,806	($278,478)
AEP Texas North Co.	**$28,234,663**	**$2,624,965**	**$40,315,156**	**$223,178**	**$1,548,323**	**($2,637,409)**	**($1,577,569)**	**$228,835**	**($2,214,642)**
230 Kingsport Power Co. - Distribution	$3,947,489	$369,132	$5,636,463	$36,771	$216,728	($368,736)	($177,403)	$31,993	($260,647)
260 Kingsport Power Co. - Transmission	$485,801	$36,671	$693,656	$2,245	$26,788	($45,379)	($40,419)	$3,937	($52,828)
Kingsport Power Co.	**$4,433,290**	**$405,803**	**$6,330,119**	**$39,016**	**$243,516**	**($414,115)**	**($217,822)**	**$35,930**	**($313,475)**
210 Wheeling Power Co. - Distribution	$5,083,618	$467,321	$7,258,697	$35,336	$278,646	($474,863)	($259,071)	$41,201	($378,751)
200 Wheeling Power Co. - Transmission	$240,157	$39,144	$342,911	$0	$12,589	($22,433)	($2,613)	$1,946	($10,511)
Wheeling Power Co.	**$5,323,775**	**$506,465**	**$7,601,608**	**$35,336**	**$291,235**	**($497,296)**	**($261,684)**	**$43,147**	**($389,262)**
103 American Electric Power Service Corporation	$273,746,199	$22,904,612	$390,871,347	$3,468,043	$15,157,479	($25,570,725)	($17,282,221)	$2,218,648	($22,008,776)
American Electric Power Service Corporation	**$273,746,199**	**$22,904,612**	**$390,871,347**	**$3,468,043**	**$15,157,479**	**($25,570,725)**	**($17,282,221)**	**$2,218,648**	**($22,008,776)**
143 AEP Pro Serv, Inc.	$91,349	$12,020	$130,434	$0	$4,869	($8,533)	($1,133)	$740	($4,057)
171 CSW Energy, Inc.	$1,213,345	$40,448	$1,732,487	$46,659	$70,683	($113,339)	($47,052)	$9,834	($33,215)
293 Elmwood	$2,033,686	$136,704	$2,903,820	$79,656	$116,618	($189,967)	($276,067)	$16,483	($253,277)
292 AEP River Operations LLC	$11,857,038	$633,649	$16,930,195	$609,069	$692,759	($1,107,570)	($1,245,634)	$96,098	($955,278)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$15,195,418**	**$822,821**	**$21,696,936**	**$735,384**	**$884,929**	**($1,419,409)**	**($1,569,886)**	**$123,155**	**($1,245,827)**
270 Cook Coal Terminal	$1,148,209	$116,355	$1,639,482	$9,019	$62,692	($107,255)	($67,747)	$9,306	($93,985)
AEP Generating Company	**$1,148,209**	**$116,355**	**$1,639,482**	**$9,019**	**$62,692**	**($107,255)**	**($67,747)**	**$9,306**	**($93,985)**
104 Cardinal Operating Company	$19,493,279	$1,722,458	$27,833,680	$211,255	$1,074,749	($1,820,874)	($1,116,823)	$157,988	($1,493,705)
181 Ohio Power Co. - Generation	$89,738,449	$8,713,851	$128,133,974	$459,207	$4,896,363	($8,382,499)	($4,359,566)	$727,308	($6,659,187)
AEP Generation Resources - FERC	**$109,231,728**	**$10,436,309**	**$155,967,654**	**$670,462**	**$5,971,112**	**($10,203,373)**	**($5,476,389)**	**$885,296**	**($8,152,892)**
290 Conesville Coal Preparation Company	$1,034,648	$117,405	$1,477,333	$0	$55,675	($96,647)	($51,555)	$8,386	($84,141)
AEP Generation Resources - SEC	**$110,266,376**	**$10,553,714**	**$157,444,987**	**$670,462**	**$6,026,787**	**($10,300,020)**	**($5,527,944)**	**$893,682**	**($8,237,033)**
Total	**$1,196,922,413**	**$107,085,950**	**$1,709,038,069**	**$12,264,557**	**$65,914,001**	**($111,804,933)**	**($69,056,806)**	**$9,700,764**	**($92,982,417)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2019 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$95,575,909	$9,255,802	$141,530,529	$726,722	$5,320,917	($9,266,680)	($5,097,397)	$647,142	($7,669,296)
215 Appalachian Power Co. - Generation	$79,637,663	$7,495,628	$117,928,887	$624,866	$4,440,917	($7,721,367)	($4,162,884)	$539,225	($6,279,243)
150 Appalachian Power Co. - Transmission	$11,121,488	$877,554	$16,468,900	$34,277	$621,944	($1,078,298)	($781,538)	$75,303	($1,128,312)
Appalachian Power Co. - FERC	**$186,335,060**	**$17,628,984**	**$275,928,316**	**$1,385,865**	**$10,383,778**	**($18,066,345)**	**($10,041,819)**	**$1,261,670**	**($15,076,851)**
225 Cedar Coal Co	$540,364	$88,720	$800,181	$0	$28,804	($52,392)	($8,202)	$3,659	($28,131)
Appalachian Power Co. - SEC	**$186,875,424**	**$17,717,704**	**$276,728,497**	**$1,385,865**	**$10,412,582**	**($18,118,737)**	**($10,050,021)**	**$1,265,329**	**($15,104,982)**
211 AEP Texas Central Company - Distribution	$69,437,532	$6,376,144	$102,824,349	$614,778	$3,880,732	($6,732,401)	($3,881,048)	$470,160	($5,647,779)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$6,497,424	$577,021	$9,621,503	$70,670	$364,452	($629,966)	($391,921)	$43,994	($542,771)
AEP Texas Central Co.	**$75,934,956**	**$6,953,165**	**$112,445,852**	**$685,448**	**$4,245,184**	**($7,362,367)**	**($4,288,306)**	**$514,154**	**($6,205,887)**
170 Indiana Michigan Power Co. - Distribution	$46,469,483	$4,772,026	$68,812,848	$402,749	$2,582,151	($4,505,506)	($2,601,438)	$314,644	($3,807,400)
132 Indiana Michigan Power Co. - Generation	$27,845,239	$2,621,868	$41,233,732	$291,386	$1,556,962	($2,699,769)	($1,850,054)	$188,539	($2,512,936)
190 Indiana Michigan Power Co. - Nuclear	$47,177,078	$3,951,108	$69,860,667	$898,346	$2,675,407	($4,574,112)	($3,561,730)	$319,435	($4,242,654)
120 Indiana Michigan Power Co. - Transmission	$10,069,791	$859,548	$14,911,528	$81,464	$564,197	($976,329)	($596,815)	$68,182	($859,301)
280 Ind Mich River Transp Lakin	$11,546,102	$989,132	$17,097,676	$190,440	$652,439	($1,119,467)	($811,278)	$78,178	($1,009,688)
Indiana Michigan Power Co. - FERC	**$143,107,693**	**$13,193,682**	**$211,916,451**	**$1,864,385**	**$8,031,156**	**($13,875,183)**	**($9,421,315)**	**$968,978**	**($12,431,979)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$143,107,693**	**$13,193,682**	**$211,916,451**	**$1,864,385**	**$8,031,156**	**($13,875,183)**	**($9,421,315)**	**$968,978**	**($12,431,979)**
110 Kentucky Power Co. - Distribution	$17,951,054	$1,654,727	$26,582,244	$154,538	$1,002,814	($1,740,466)	($1,210,578)	$121,546	($1,672,146)
117 Kentucky Power Co. - Generation	$11,929,998	$1,052,591	$17,666,156	$55,863	$665,085	($1,156,688)	($611,828)	$80,778	($966,790)
180 Kentucky Power Co. - Transmission	$1,821,244	$136,906	$2,696,931	$20,065	$102,882	($176,581)	($198,150)	$12,332	($239,452)
600 Kentucky Power Co. - Kammer Actives	$1,268,049	$105,599	$1,877,750	$36,450	$72,642	($122,945)	($42,530)	$8,586	($47,797)
701 Kentucky Power Co. - Mitchell Actives	$6,463,535	$517,123	$9,571,319	$185,540	$370,861	($626,680)	($160,767)	$43,764	($187,282)
702 Kentucky Power Co. - Mitchell Inactives	$5,919,566	$556,813	$8,765,800	$0	$327,415	($573,939)	($200,743)	$40,081	($407,186)
Kentucky Power Co.	**$45,353,446**	**$4,023,759**	**$67,160,200**	**$452,456**	**$2,541,699**	**($4,397,299)**	**($2,424,596)**	**$307,087**	**($3,520,653)**
250 Ohio Power Co. - Distribution	$121,581,306	$11,707,587	$180,039,789	$974,683	$6,773,513	($11,788,065)	($5,890,962)	$823,224	($9,107,607)
160 Ohio Power Co. - Transmission	$14,559,862	$1,309,373	$21,560,506	$7,381	$807,463	($1,411,669)	($1,031,548)	$98,584	($1,529,789)
Ohio Power Co.	**$136,141,168**	**$13,016,960**	**$201,600,295**	**$982,064**	**$7,580,976**	**($13,199,734)**	**($6,922,510)**	**$921,808**	**($10,637,396)**
167 Public Service Co. of Oklahoma - Distribution	$41,830,523	$3,775,033	$61,943,392	$453,008	$2,344,512	($4,055,730)	($2,477,659)	$283,233	($3,452,636)
198 Public Service Co. of Oklahoma - Generation	$20,668,486	$1,842,296	$30,606,267	$289,894	$1,162,912	($2,003,938)	($1,498,642)	$139,946	($1,909,828)
114 Public Service Co. of Oklahoma - Transmission	$4,860,435	$426,192	$7,197,420	$60,696	$273,240	($471,249)	($313,349)	$32,910	($417,752)
Public Service Co. of Oklahoma	**$67,359,444**	**$6,043,521**	**$99,747,079**	**$803,598**	**$3,780,664**	**($6,530,917)**	**($4,289,650)**	**$456,089**	**($5,780,216)**
159 Southwestern Electric Power Co. - Distribution	$29,458,679	$2,530,528	$43,622,943	$350,410	$1,656,576	($2,856,202)	($1,794,965)	$199,464	($2,444,717)
168 Southwestern Electric Power Co. - Generation	$28,924,950	$2,521,253	$42,832,587	$421,480	$1,630,007	($2,804,454)	($2,137,691)	$195,850	($2,694,808)
161 Southwestern Electric Power Co. - Texas - Distribution	$13,716,220	$1,171,658	$20,311,226	$151,540	$770,831	($1,329,873)	($942,674)	$92,872	($1,257,304)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,565,075	$371,349	$6,760,045	$45,512	$256,797	($442,612)	($280,205)	$30,910	($389,598)
Southwestern Electric Power Co.	**$76,664,924**	**$6,594,788**	**$113,526,801**	**$968,942**	**$4,314,211**	**($7,433,141)**	**($5,155,535)**	**$519,096**	**($6,786,427)**
119 AEP Texas North Company - Distribution	$19,573,413	$1,814,405	$28,984,663	$188,625	$1,094,322	($1,897,764)	($1,276,048)	$132,531	($1,758,334)
166 AEP Texas North Company - Generation	$4,941,699	$530,260	$7,317,757	$0	$271,458	($479,128)	($67,677)	$33,460	($241,887)
192 AEP Texas North Company - Transmission	$2,615,000	$240,537	$3,872,339	$36,401	$146,904	($253,541)	($233,844)	$17,706	($286,374)
AEP Texas North Co.	**$27,130,112**	**$2,585,202**	**$40,174,759**	**$225,026**	**$1,512,684**	**($2,630,433)**	**($1,577,569)**	**$183,697**	**($2,286,595)**
230 Kingsport Power Co. - Distribution	$3,796,718	$338,858	$5,622,248	$37,075	$212,672	($368,115)	($177,403)	$25,707	($270,064)
260 Kingsport Power Co. - Transmission	$473,778	$37,771	$701,579	$2,264	$26,531	($45,936)	($40,419)	$3,208	($54,352)
Kingsport Power Co.	**$4,270,496**	**$376,629**	**$6,323,827**	**$39,339**	**$239,203**	**($414,051)**	**($217,822)**	**$28,915**	**($324,416)**
210 Wheeling Power Co. - Distribution	$4,885,068	$474,169	$7,233,897	$35,628	$271,843	($473,638)	($259,071)	$33,077	($392,161)
200 Wheeling Power Co. - Transmission	$211,643	$36,450	$313,405	$0	$11,233	($20,520)	($2,613)	$1,433	($10,467)
Wheeling Power Co.	**$5,096,711**	**$510,619**	**$7,547,302**	**$35,628**	**$283,076**	**($494,158)**	**($261,684)**	**$34,510**	**($402,628)**
103 American Electric Power Service Corporation	$266,996,088	$22,435,670	$395,372,621	$3,496,750	$15,047,122	($25,886,933)	($17,282,221)	$1,807,820	($22,817,462)
American Electric Power Service Corporation	**$266,996,088**	**$22,435,670**	**$395,372,621**	**$3,496,750**	**$15,047,122**	**($25,886,933)**	**($17,282,221)**	**$1,807,820**	**($22,817,462)**
143 AEP Pro Serv, Inc.	$83,426	$12,313	$123,539	$0	$4,487	($8,089)	($1,133)	$565	($4,170)
171 CSW Energy, Inc.	$1,278,407	$47,173	$1,893,088	$47,045	$75,527	($123,950)	($47,052)	$8,656	($39,774)
293 Elmwood	$2,074,061	$138,960	$3,071,307	$80,315	$120,981	($201,093)	($276,067)	$14,043	($261,821)
292 AEP River Operations LLC	$12,410,360	$640,830	$18,377,485	$614,111	$737,097	($1,203,262)	($1,245,634)	$84,030	($1,013,658)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$15,846,254**	**$839,276**	**$23,465,419**	**$741,471**	**$938,092**	**($1,536,394)**	**($1,569,886)**	**$107,294**	**($1,319,423)**
270 Cook Coal Terminal	$1,093,445	$115,400	$1,619,193	$9,094	$60,648	($106,016)	($67,747)	$7,404	($96,617)
AEP Generating Company	**$1,093,445**	**$115,400**	**$1,619,193**	**$9,094**	**$60,648**	**($106,016)**	**($67,747)**	**$7,404**	**($96,617)**
104 Cardinal Operating Company	$18,882,073	$1,664,987	$27,960,914	$213,004	$1,059,910	($1,830,735)	($1,116,823)	$127,850	($1,546,794)
181 Ohio Power Co. - Generation	$85,588,060	$8,356,651	$126,740,342	$463,008	$4,752,035	($8,298,295)	($4,359,566)	$579,515	($6,863,303)
AEP Generation Resources - FERC	**$104,470,133**	**$10,021,638**	**$154,701,256**	**$676,012**	**$5,811,945**	**($10,129,030)**	**($5,476,389)**	**$707,365**	**($8,410,097)**
290 Conesville Coal Preparation Company	$963,996	$115,807	$1,427,503	$0	$52,601	($93,465)	($51,555)	$6,527	($85,892)
AEP Generation Resources - SEC	**$105,434,129**	**$10,137,445**	**$156,128,759**	**$676,012**	**$5,864,546**	**($10,222,495)**	**($5,527,944)**	**$713,892**	**($8,495,989)**
Total	**$1,157,304,290**	**$104,543,820**	**$1,713,757,055**	**$12,366,078**	**$64,851,843**	**($112,207,858)**	**($69,056,806)**	**$7,836,073**	**($96,210,670)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2020 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations*		*Net Periodic Postretirement Benefit Cost*
							PSC	*(G)/L*	
140 Appalachian Power Co. - Distribution	$92,367,746	$9,066,380	$140,714,006	$743,982	$5,141,261	($9,218,901)	($5,097,397)	$582,123	($7,848,932)
215 Appalachian Power Co. - Generation	$77,207,818	$7,270,916	$117,619,210	$639,707	$4,307,272	($7,705,842)	($4,162,884)	$486,582	($6,435,165)
150 Appalachian Power Co. - Transmission	$10,900,155	$852,271	$16,605,412	$35,091	$609,877	($1,087,906)	($781,538)	$68,695	($1,155,781)
Appalachian Power Co. - FERC	**$180,475,719**	**$17,189,567**	**$274,938,628**	**$1,418,780**	**$10,058,410**	**($18,012,649)**	**($10,041,819)**	**$1,137,400**	**($15,439,878)**
225 Cedar Coal Co	$480,448	$79,688	$731,920	$0	$25,588	($47,952)	($8,202)	$3,028	($27,538)
Appalachian Power Co. - SEC	**$180,956,167**	**$17,269,255**	**$275,670,548**	**$1,418,780**	**$10,083,998**	**($18,060,601)**	**($10,050,021)**	**$1,140,428**	**($15,467,416)**
211 AEP Texas Central Company - Distribution	$67,556,898	$6,244,142	$102,916,896	$629,379	$3,776,276	($6,742,617)	($3,881,048)	$425,759	($5,792,251)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$6,355,525	$576,781	$9,682,074	$72,348	$356,326	($634,323)	($391,921)	$40,054	($557,516)
AEP Texas Central Co.	**$73,912,423**	**$6,820,923**	**$112,598,970**	**$701,727**	**$4,132,602**	**($7,376,940)**	**($4,288,306)**	**$465,813**	**($6,365,104)**
170 Indiana Michigan Power Co. - Distribution	$44,682,357	$4,584,069	$68,069,578	$412,314	$2,484,427	($4,459,590)	($2,601,438)	$281,599	($3,882,688)
132 Indiana Michigan Power Co. - Generation	$27,071,719	$2,614,398	$41,241,344	$298,306	$1,512,712	($2,701,933)	($1,850,054)	$170,612	($2,570,357)
190 Indiana Michigan Power Co. - Nuclear	$46,799,723	$3,993,750	$71,295,195	$919,682	$2,653,539	($4,670,916)	($3,561,730)	$294,943	($4,364,482)
120 Indiana Michigan Power Co. - Transmission	$9,855,904	$842,268	$15,014,589	$83,399	$552,398	($983,683)	($596,815)	$62,114	($882,587)
280 Ind Mich River Transp Lakin	$11,399,849	$996,047	$17,366,651	$194,963	$644,021	($1,137,779)	($811,278)	$71,845	($1,038,228)
Indiana Michigan Power Co. - FERC	**$139,809,552**	**$13,030,532**	**$212,987,357**	**$1,908,664**	**$7,847,097**	**($13,953,901)**	**($9,421,315)**	**$881,113**	**($12,738,342)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$139,809,552**	**$13,030,532**	**$212,987,357**	**$1,908,664**	**$7,847,097**	**($13,953,901)**	**($9,421,315)**	**$881,113**	**($12,738,342)**
110 Kentucky Power Co. - Distribution	$17,453,679	$1,674,438	$26,589,120	$158,208	$973,615	($1,741,991)	($1,210,578)	$109,997	($1,710,749)
117 Kentucky Power Co. - Generation	$11,598,355	$1,027,853	$17,669,057	$57,190	$646,634	($1,157,591)	($611,828)	$73,096	($992,499)
180 Kentucky Power Co. - Transmission	$1,807,285	$143,085	$2,753,237	$20,542	$101,923	($180,379)	($198,150)	$11,390	($244,674)
600 Kentucky Power Co. - Kammer Actives	$1,271,542	$128,956	$1,937,081	$37,316	$72,227	($126,908)	($42,530)	$8,014	($51,881)
701 Kentucky Power Co. - Mitchell Actives	$6,502,813	$545,040	$9,906,454	$189,947	$372,597	($649,023)	($160,767)	$40,982	($206,264)
702 Kentucky Power Co. - Mitchell Inactives	$5,690,168	$510,203	$8,668,462	$0	$315,442	($567,916)	($200,743)	$35,861	($417,356)
Kentucky Power Co.	**$44,323,842**	**$4,029,575**	**$67,523,411**	**$463,203**	**$2,482,438**	**($4,423,808)**	**($2,424,596)**	**$279,340**	**($3,623,423)**
250 Ohio Power Co. - Distribution	$117,621,915	$11,378,042	$179,186,475	$997,832	$6,554,633	($11,739,431)	($5,890,962)	$741,281	($9,336,647)
160 Ohio Power Co. - Transmission	$14,065,333	$1,245,120	$21,427,278	$7,556	$780,628	($1,403,812)	($1,031,548)	$88,643	($1,558,533)
Ohio Power Co.	**$131,687,248**	**$12,623,162**	**$200,613,753**	**$1,005,388**	**$7,335,261**	**($13,143,243)**	**($6,922,510)**	**$829,924**	**($10,895,180)**
167 Public Service Co. of Oklahoma - Distribution	$40,853,010	$3,757,927	$62,235,910	$463,767	$2,288,929	($4,077,396)	($2,477,659)	$257,465	($3,544,894)
198 Public Service Co. of Oklahoma - Generation	$20,278,996	$1,870,651	$30,893,238	$296,779	$1,139,911	($2,023,976)	($1,498,642)	$127,803	($1,958,125)
114 Public Service Co. of Oklahoma - Transmission	$4,768,179	$434,213	$7,263,895	$62,138	$267,744	($475,895)	($313,349)	$30,050	($429,312)
Public Service Co. of Oklahoma	**$65,900,185**	**$6,062,791**	**$100,393,043**	**$822,684**	**$3,696,584**	**($6,577,267)**	**($4,289,650)**	**$415,318**	**($5,932,331)**
159 Southwestern Electric Power Co. - Distribution	$28,935,137	$2,522,049	$44,080,095	$358,732	$1,626,936	($2,887,915)	($1,794,965)	$182,356	($2,514,856)
168 Southwestern Electric Power Co. - Generation	$28,455,184	$2,555,399	$43,348,930	$431,490	$1,602,365	($2,840,012)	($2,137,691)	$179,331	($2,764,517)
161 Southwestern Electric Power Co. - Texas - Distribution	$13,466,933	$1,171,173	$20,515,669	$155,139	$756,595	($1,344,087)	($942,674)	$84,872	($1,290,155)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,496,035	$373,094	$6,849,308	$46,593	$252,805	($448,734)	($280,205)	$28,335	($401,206)
Southwestern Electric Power Co.	**$75,353,289**	**$6,621,715**	**$114,794,002**	**$991,954**	**$4,238,701**	**($7,520,748)**	**($5,155,535)**	**$474,894**	**($6,970,734)**
119 AEP Texas North Company - Distribution	$19,041,955	$1,801,218	$29,008,717	$193,105	$1,064,134	($1,900,511)	($1,276,048)	$120,007	($1,799,313)
166 AEP Texas North Company - Generation	$4,682,897	$503,906	$7,133,975	$0	$257,201	($467,384)	($67,677)	$29,513	($248,347)
192 AEP Texas North Company - Transmission	$2,557,768	$244,087	$3,896,531	$37,266	$143,533	($255,282)	($233,844)	$16,120	($292,207)
AEP Texas North Co.	**$26,282,620**	**$2,549,211**	**$40,039,223**	**$230,371**	**$1,464,868**	**($2,623,177)**	**($1,577,569)**	**$165,640**	**($2,339,867)**
230 Kingsport Power Co. - Distribution	$3,707,607	$335,170	$5,648,208	$37,956	$207,660	($370,043)	($177,403)	$23,366	($278,464)
260 Kingsport Power Co. - Transmission	$464,802	$36,192	$708,084	$2,318	$26,058	($46,390)	($40,419)	$2,929	($55,504)
Kingsport Power Co.	**$4,172,409**	**$371,362**	**$6,356,292**	**$40,274**	**$233,718**	**($416,433)**	**($217,822)**	**$26,295**	**($333,968)**
210 Wheeling Power Co. - Distribution	$4,718,370	$469,462	$7,188,015	$36,474	$262,358	($470,924)	($259,071)	$29,736	($401,427)
200 Wheeling Power Co. - Transmission	$186,426	$33,573	$284,003	$0	$9,853	($18,607)	($2,613)	$1,175	($10,192)
Wheeling Power Co.	**$4,904,796**	**$503,035**	**$7,472,018**	**$36,474**	**$272,211**	**($489,531)**	**($261,684)**	**$30,911**	**($411,619)**
103 American Electric Power Service Corporation	$263,104,290	$22,278,129	$400,815,873	$3,579,800	$14,830,718	($26,259,516)	($17,282,221)	$1,658,145	($23,473,074)
American Electric Power Service Corporation	**$263,104,290**	**$22,278,129**	**$400,815,873**	**$3,579,800**	**$14,830,718**	**($26,259,516)**	**($17,282,221)**	**$1,658,145**	**($23,473,074)**
143 AEP Pro Serv, Inc.	$75,600	$3,598	$115,170	$0	$4,282	($7,545)	($1,133)	$476	($3,920)
171 CSW Energy, Inc.	$1,353,806	$48,811	$2,062,402	$48,162	$79,919	($135,119)	($47,052)	$8,532	($45,558)
293 Elmwood	$2,136,397	$153,408	$3,254,610	$82,222	$124,294	($213,226)	($276,067)	$13,464	($269,313)
292 AEP River Operations LLC	$13,120,738	$717,509	$19,988,272	$628,696	$776,953	($1,309,535)	($1,245,634)	$82,690	($1,066,830)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$16,686,541**	**$923,326**	**$25,420,454**	**$759,080**	**$985,448**	**($1,665,425)**	**($1,569,886)**	**$105,162**	**($1,385,621)**
270 Cook Coal Terminal	$1,047,787	$111,433	$1,596,210	$9,310	$58,126	($104,576)	($67,747)	$6,603	($98,284)
AEP Generating Company	**$1,047,787**	**$111,433**	**$1,596,210**	**$9,310**	**$58,126**	**($104,576)**	**($67,747)**	**$6,603**	**($98,284)**
104 Cardinal Operating Company	$18,490,000	$1,667,496	$28,167,863	$218,063	$1,037,392	($1,845,422)	($1,116,823)	$116,528	($1,590,262)
181 Ohio Power Co. - Generation	$82,446,452	$7,945,778	$125,599,801	$474,004	$4,582,207	($8,228,692)	($4,359,566)	$519,597	($7,012,450)
AEP Generation Resources - FERC	**$100,936,452**	**$9,613,274**	**$153,767,664**	**$692,067**	**$5,619,599**	**($10,074,114)**	**($5,476,389)**	**$636,125**	**($8,602,712)**
290 Conesville Coal Preparation Company	$900,790	$109,397	$1,372,273	$0	$49,118	($89,905)	($51,555)	$5,677	($86,665)
AEP Generation Resources - SEC	**$101,837,242**	**$9,722,671**	**$155,139,937**	**$692,067**	**$5,668,717**	**($10,164,019)**	**($5,527,944)**	**$641,802**	**($8,689,377)**
Total	**$1,129,978,391**	**$102,917,120**	**$1,721,421,091**	**$12,659,776**	**$63,330,487**	**($112,779,185)**	**($69,056,806)**	**$7,121,388**	**($98,724,340)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2021 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$89,186,609	$8,932,583	$139,981,922	$761,652	$4,961,605	($9,175,528)	($5,097,397)	$518,820	($8,030,848)
215 Appalachian Power Co. - Generation	$74,883,881	$7,070,254	$117,533,223	$654,900	$4,179,102	($7,704,062)	($4,162,884)	$435,618	($6,597,326)
150 Appalachian Power Co. - Transmission	$10,692,852	$853,935	$16,782,856	$35,924	$597,854	($1,100,082)	($781,538)	$62,203	($1,185,639)
Appalachian Power Co. - FERC	**$174,763,342**	**$16,856,772**	**$274,298,001**	**$1,452,476**	**$9,738,561**	**($17,979,672)**	**($10,041,819)**	**$1,016,641**	**($15,813,813)**
225 Cedar Coal Co	$426,348	$72,031	$669,170	$0	$22,669	($43,863)	($8,202)	$2,480	($26,916)
Appalachian Power Co. - SEC	**$175,189,690**	**$16,928,803**	**$274,967,171**	**$1,452,476**	**$9,761,230**	**($18,023,535)**	**($10,050,021)**	**$1,019,121**	**($15,840,729)**
211 AEP Texas Central Company - Distribution	$65,718,411	$6,234,144	$103,147,654	$644,327	$3,670,797	($6,761,117)	($3,881,048)	$382,300	($5,944,741)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$6,207,418	$562,727	$9,742,789	$74,066	$348,237	($638,620)	($391,921)	$36,110	($572,128)
AEP Texas Central Co.	**$71,925,829**	**$6,796,871**	**$112,890,443**	**$718,393**	**$4,019,034**	**($7,399,737)**	**($4,288,306)**	**$418,410**	**($6,532,206)**
170 Indiana Michigan Power Co. - Distribution	$42,995,029	$4,446,602	$67,482,404	$422,106	$2,391,060	($4,423,333)	($2,601,438)	$250,113	($3,961,492)
132 Indiana Michigan Power Co. - Generation	$26,268,339	$2,658,575	$41,229,201	$305,391	$1,465,264	($2,702,490)	($1,850,054)	$152,809	($2,629,080)
190 Indiana Michigan Power Co. - Nuclear	$46,379,194	$4,051,131	$72,793,986	$941,524	$2,628,775	($4,771,497)	($3,561,730)	$269,799	($4,493,129)
120 Indiana Michigan Power Co. - Transmission	$9,649,433	$836,380	$15,145,168	$85,380	$540,706	($992,735)	($596,815)	$56,133	($907,331)
280 Ind Mich River Transp Lakin	$11,242,786	$981,416	$17,645,999	$199,593	$635,598	($1,156,659)	($811,278)	$65,402	($1,067,344)
Indiana Michigan Power Co. - FERC	**$136,534,781**	**$12,974,104**	**$214,296,758**	**$1,953,994**	**$7,661,403**	**($14,046,714)**	**($9,421,315)**	**$794,256**	**($13,058,376)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$136,534,781**	**$12,974,104**	**$214,296,758**	**$1,953,994**	**$7,661,403**	**($14,046,714)**	**($9,421,315)**	**$794,256**	**($13,058,376)**
110 Kentucky Power Co. - Distribution	$16,911,064	$1,653,152	$26,542,586	$161,965	$942,970	($1,739,812)	($1,210,578)	$98,376	($1,747,079)
117 Kentucky Power Co. - Generation	$11,274,326	$1,040,687	$17,695,502	$58,548	$627,552	($1,159,904)	($611,828)	$65,585	($1,020,047)
180 Kentucky Power Co. - Transmission	$1,786,665	$127,938	$2,804,242	$21,030	$101,188	($183,812)	($198,150)	$10,393	($249,351)
600 Kentucky Power Co. - Kammer Actives	$1,252,129	$139,518	$1,965,266	$38,202	$70,850	($128,819)	($42,530)	$7,284	($55,013)
701 Kentucky Power Co. - Mitchell Actives	$6,520,317	$613,139	$10,233,896	$194,458	$371,927	($670,811)	($160,767)	$37,930	($227,263)
702 Kentucky Power Co. - Mitchell Inactives	$5,495,407	$506,678	$8,625,259	$0	$304,247	($565,368)	($200,743)	$31,968	($429,896)
Kentucky Power Co.	**$43,239,908**	**$4,081,112**	**$67,866,751**	**$474,203**	**$2,418,734**	**($4,448,526)**	**($2,424,596)**	**$251,536**	**($3,728,649)**
250 Ohio Power Co. - Distribution	$113,796,338	$11,176,052	$178,607,868	$1,021,531	$6,339,899	($11,707,380)	($5,890,962)	$661,981	($9,574,931)
160 Ohio Power Co. - Transmission	$13,608,397	$1,196,214	$21,358,919	$7,735	$755,534	($1,400,033)	($1,031,548)	$79,163	($1,589,149)
Ohio Power Co.	**$127,404,735**	**$12,372,266**	**$199,966,787**	**$1,029,266**	**$7,095,433**	**($13,107,413)**	**($6,922,510)**	**$741,144**	**($11,164,080)**
167 Public Service Co. of Oklahoma - Distribution	$39,847,779	$3,663,711	$62,542,670	$474,781	$2,233,958	($4,099,544)	($2,477,659)	$231,804	($3,636,660)
198 Public Service Co. of Oklahoma - Generation	$19,845,035	$1,831,940	$31,147,570	$303,828	$1,116,257	($2,041,659)	($1,498,642)	$115,443	($2,004,773)
114 Public Service Co. of Oklahoma - Transmission	$4,663,848	$428,401	$7,320,095	$63,614	$261,944	($479,817)	($313,349)	$27,131	($440,477)
Public Service Co. of Oklahoma	**$64,356,662**	**$5,924,052**	**$101,010,335**	**$842,223**	**$3,612,159**	**($6,621,020)**	**($4,289,650)**	**$374,378**	**($6,081,910)**
159 Southwestern Electric Power Co. - Distribution	$28,398,756	$2,579,272	$44,572,975	$367,252	$1,594,684	($2,921,667)	($1,794,965)	$165,202	($2,589,494)
168 Southwestern Electric Power Co. - Generation	$27,933,640	$2,632,907	$43,842,957	$441,738	$1,570,494	($2,873,816)	($2,137,691)	$162,497	($2,836,778)
161 Southwestern Electric Power Co. - Texas - Distribution	$13,207,494	$1,136,448	$20,729,686	$158,824	$742,754	($1,358,788)	($942,674)	$76,831	($1,323,053)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,422,339	$367,565	$6,941,037	$47,700	$248,753	($454,971)	($280,205)	$25,726	($412,997)
Southwestern Electric Power Co.	**$73,962,229**	**$6,716,192**	**$116,086,655**	**$1,015,514**	**$4,156,685**	**($7,609,242)**	**($5,155,535)**	**$430,256**	**($7,162,322)**
119 AEP Texas North Company - Distribution	$18,497,976	$1,776,179	$29,033,307	$197,691	$1,033,565	($1,903,074)	($1,276,048)	$107,607	($1,840,259)
166 AEP Texas North Company - Generation	$4,436,192	$495,795	$6,962,779	$0	$243,124	($456,396)	($67,677)	$25,806	($255,143)
192 AEP Texas North Company - Transmission	$2,494,480	$244,719	$3,915,185	$38,151	$139,896	($256,632)	($233,844)	$14,511	($297,918)
AEP Texas North Co.	**$25,428,648**	**$2,516,693**	**$39,911,271**	**$235,842**	**$1,416,585**	**($2,616,102)**	**($1,577,569)**	**$147,924**	**($2,393,320)**
230 Kingsport Power Co. - Distribution	$3,618,053	$336,311	$5,678,678	$38,857	$202,485	($372,226)	($177,403)	$21,047	($287,240)
260 Kingsport Power Co. - Transmission	$456,986	$37,405	$717,258	$2,373	$25,573	($47,015)	($40,419)	$2,658	($56,830)
Kingsport Power Co.	**$4,075,039**	**$373,716**	**$6,395,936**	**$41,230**	**$228,058**	**($419,241)**	**($217,822)**	**$23,705**	**($344,070)**
210 Wheeling Power Co. - Distribution	$4,547,740	$464,282	$7,137,858	$37,340	$252,660	($467,872)	($259,071)	$26,455	($410,488)
200 Wheeling Power Co. - Transmission	$162,706	$30,766	$255,374	$0	$8,557	($16,739)	($2,613)	$947	($9,848)
Wheeling Power Co.	**$4,710,446**	**$495,048**	**$7,393,232**	**$37,340**	**$261,217**	**($484,611)**	**($261,684)**	**$27,402**	**($420,336)**
103 American Electric Power Service Corporation	$259,236,679	$21,977,717	$406,882,254	$3,664,819	$14,619,916	($26,670,296)	($17,282,221)	$1,508,043	($24,159,739)
American Electric Power Service Corporation	**$259,236,679**	**$21,977,717**	**$406,882,254**	**$3,664,819**	**$14,619,916**	**($26,670,296)**	**($17,282,221)**	**$1,508,043**	**($24,159,739)**
143 AEP Pro Serv, Inc.	$76,284	$3,683	$119,731	$0	$4,319	($7,848)	($1,133)	$444	($4,218)
171 CSW Energy, Inc.	$1,433,076	$58,071	$2,249,270	$49,306	$84,318	($147,435)	($47,052)	$8,337	($52,526)
293 Elmwood	$2,189,505	$165,227	$3,436,515	$84,175	$127,149	($225,257)	($276,067)	$12,737	($277,263)
292 AEP River Operations LLC	$13,808,878	$813,112	$21,673,582	$643,628	$814,997	($1,420,659)	($1,245,634)	$80,330	($1,127,338)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$17,507,743**	**$1,040,093**	**$27,479,098**	**$777,109**	**$1,030,783**	**($1,801,199)**	**($1,569,886)**	**$101,848**	**($1,461,345)**
270 Cook Coal Terminal	$1,003,790	$105,683	$1,575,488	$9,531	$55,751	($103,270)	($67,747)	$5,839	($99,896)
AEP Generating Company	**$1,003,790**	**$105,683**	**$1,575,488**	**$9,531**	**$55,751**	**($103,270)**	**($67,747)**	**$5,839**	**($99,896)**
104 Cardinal Operating Company	$18,077,959	$1,676,079	$28,374,074	$223,242	$1,013,548	($1,859,862)	($1,116,823)	$105,164	($1,634,731)
181 Ohio Power Co. - Generation	$79,556,885	$7,708,310	$124,867,688	$485,262	$4,422,054	($8,184,821)	($4,359,566)	$462,802	($7,174,269)
AEP Generation Resources - FERC	**$97,634,844**	**$9,384,389**	**$153,241,762**	**$708,504**	**$5,435,602**	**($10,044,683)**	**($5,476,389)**	**$567,966**	**($8,809,000)**
290 Conesville Coal Preparation Company	$840,511	$110,302	$1,319,215	$0	$45,596	($86,472)	($51,555)	$4,889	($87,542)
AEP Generation Resources - SEC	**$98,475,355**	**$9,494,691**	**$154,560,977**	**$708,504**	**$5,481,198**	**($10,131,155)**	**($5,527,944)**	**$572,855**	**($8,896,542)**
Total	**$1,103,051,534**	**$101,797,041**	**$1,731,283,156**	**$12,960,444**	**$61,818,186**	**($113,482,061)**	**($69,056,806)**	**$6,416,717**	**($101,343,520)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2022 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$85,977,283	$8,665,229	$139,266,780	$779,741	$4,784,157	($9,136,250)	($5,097,397)	$458,315	($8,211,434)
215 Appalachian Power Co. - Generation	$72,647,629	$6,833,119	$117,675,286	$670,454	$4,057,081	($7,719,793)	($4,162,884)	$387,259	($6,767,883)
150 Appalachian Power Co. - Transmission	$10,472,695	$859,972	$16,963,766	$36,777	$584,962	($1,112,866)	($781,538)	$55,826	($1,216,839)
Appalachian Power Co. - FERC	**$169,097,607**	**$16,358,320**	**$273,905,832**	**$1,486,972**	**$9,426,200**	**($17,968,909)**	**($10,041,819)**	**$901,400**	**($16,196,156)**
225 Cedar Coal Co	$376,986	$64,107	$610,645	$0	$20,032	($40,060)	($8,202)	$2,010	($26,220)
Appalachian Power Co. - SEC	**$169,474,593**	**$16,422,427**	**$274,516,477**	**$1,486,972**	**$9,446,232**	**($18,008,969)**	**($10,050,021)**	**$903,410**	**($16,222,376)**
211 AEP Texas Central Company - Distribution	$63,799,391	$6,143,740	$103,342,830	$659,630	$3,562,966	($6,779,548)	($3,881,048)	$340,093	($6,097,907)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($15,337)	$0	($15,337)
169 AEP Texas Central Company - Transmission	$6,066,994	$548,479	$9,827,372	$75,825	$340,602	($644,700)	($391,921)	$32,341	($587,853)
AEP Texas Central Co.	**$69,866,385**	**$6,692,219**	**$113,170,202**	**$735,455**	**$3,903,568**	**($7,424,248)**	**($4,288,306)**	**$372,434**	**($6,701,097)**
170 Indiana Michigan Power Co. - Distribution	$41,361,593	$4,264,965	$66,997,882	$432,131	$2,302,095	($4,395,229)	($2,601,438)	$220,484	($4,041,957)
132 Indiana Michigan Power Co. - Generation	$25,380,419	$2,547,736	$41,111,432	$312,644	$1,417,355	($2,697,013)	($1,850,054)	$135,294	($2,681,774)
190 Indiana Michigan Power Co. - Nuclear	$45,898,362	$3,974,362	$74,346,582	$963,885	$2,604,378	($4,877,322)	($3,561,730)	$244,668	($4,626,121)
120 Indiana Michigan Power Co. - Transmission	$9,439,139	$846,708	$15,289,603	$87,408	$528,331	($1,003,036)	($596,815)	$50,317	($933,795)
280 Ind Mich River Transp Lakin	$11,096,561	$958,021	$17,974,310	$204,333	$628,061	($1,179,160)	($811,278)	$59,152	($1,098,892)
Indiana Michigan Power Co. - FERC	**$133,176,074**	**$12,591,792**	**$215,719,809**	**$2,000,401**	**$7,480,220**	**($14,151,760)**	**($9,421,315)**	**$709,915**	**($13,382,539)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$133,176,074**	**$12,591,792**	**$215,719,809**	**$2,000,401**	**$7,480,220**	**($14,151,760)**	**($9,421,315)**	**$709,915**	**($13,382,539)**
110 Kentucky Power Co. - Distribution	$16,362,847	$1,563,164	$26,504,687	$165,812	$913,969	($1,738,774)	($1,210,578)	$87,225	($1,782,346)
117 Kentucky Power Co. - Generation	$10,919,739	$1,002,474	$17,687,892	$59,939	$608,159	($1,160,370)	($611,828)	$58,209	($1,045,891)
180 Kentucky Power Co. - Transmission	$1,780,945	$136,676	$2,884,791	$21,529	$100,636	($189,250)	($198,150)	$9,494	($255,741)
600 Kentucky Power Co. - Kammer Actives	$1,221,663	$132,341	$1,978,861	$39,109	$69,341	($129,818)	($42,530)	$6,512	($57,386)
701 Kentucky Power Co. - Mitchell Actives	$6,473,563	$645,463	$10,485,936	$199,076	$368,558	($687,904)	($160,767)	$34,508	($246,529)
702 Kentucky Power Co. - Mitchell Inactives	$5,292,976	$479,272	$8,573,610	$0	$293,290	($562,450)	($200,743)	$28,215	($441,688)
Kentucky Power Co.	**$42,051,733**	**$3,959,390**	**$68,115,777**	**$485,465**	**$2,353,953**	**($4,468,566)**	**($2,424,596)**	**$224,163**	**($3,829,581)**
250 Ohio Power Co. - Distribution	$109,981,716	$10,927,506	$178,149,378	$1,045,792	$6,127,164	($11,687,045)	($5,890,962)	$586,275	($9,818,776)
160 Ohio Power Co. - Transmission	$13,175,452	$1,190,117	$21,341,716	$7,919	$730,609	($1,400,070)	($1,031,548)	$70,234	($1,622,856)
Ohio Power Co.	**$123,157,168**	**$12,117,623**	**$199,491,094**	**$1,053,711**	**$6,857,773**	**($13,087,115)**	**($6,922,510)**	**$656,509**	**($11,441,632)**
167 Public Service Co. of Oklahoma - Distribution	$38,892,807	$3,631,737	$62,998,920	$486,057	$2,180,138	($4,132,887)	($2,477,659)	$207,324	($3,737,027)
198 Public Service Co. of Oklahoma - Generation	$19,433,180	$1,830,021	$31,478,041	$311,044	$1,092,842	($2,065,038)	($1,498,642)	$103,592	($2,056,202)
114 Public Service Co. of Oklahoma - Transmission	$4,561,005	$425,385	$7,387,957	$65,125	$256,153	($484,668)	($313,349)	$24,313	($452,426)
Public Service Co. of Oklahoma	**$62,886,992**	**$5,887,143**	**$101,864,918**	**$862,226**	**$3,529,133**	**($6,682,593)**	**($4,289,650)**	**$335,229**	**($6,245,655)**
159 Southwestern Electric Power Co. - Distribution	$27,781,420	$2,557,925	$45,000,595	$375,974	$1,559,995	($2,952,152)	($1,794,965)	$148,093	($2,663,055)
168 Southwestern Electric Power Co. - Generation	$27,312,965	$2,572,705	$44,241,788	$452,229	$1,536,824	($2,902,372)	($2,137,691)	$145,596	($2,905,414)
161 Southwestern Electric Power Co. - Texas - Distribution	$12,972,624	$1,136,309	$21,013,174	$162,596	$729,354	($1,378,517)	($942,674)	$69,153	($1,360,088)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,351,227	$368,189	$7,048,157	$48,833	$244,676	($462,377)	($280,205)	$23,195	($425,878)
Southwestern Electric Power Co.	**$72,418,236**	**$6,635,128**	**$117,303,714**	**$1,039,632**	**$4,070,849**	**($7,695,418)**	**($5,155,535)**	**$386,037**	**($7,354,435)**
119 AEP Texas North Company - Distribution	$17,953,053	$1,754,898	$29,080,518	$202,386	$1,002,841	($1,907,755)	($1,276,048)	$95,702	($1,882,874)
166 AEP Texas North Company - Generation	$4,183,521	$483,576	$6,776,505	$0	$228,818	($444,556)	($67,677)	$22,301	($261,114)
192 AEP Texas North Company - Transmission	$2,427,808	$243,669	$3,932,585	$39,057	$136,111	($257,987)	($233,844)	$12,942	($303,721)
AEP Texas North Co.	**$24,564,382**	**$2,482,143**	**$39,789,608**	**$241,443**	**$1,367,770**	**($2,610,298)**	**($1,577,569)**	**$130,945**	**($2,447,709)**
230 Kingsport Power Co. - Distribution	$3,523,084	$329,088	$5,706,723	$39,780	$197,237	($374,375)	($177,403)	$18,780	($295,981)
260 Kingsport Power Co. - Transmission	$447,527	$39,288	$724,908	$2,429	$24,974	($47,556)	($40,419)	$2,386	($58,186)
Kingsport Power Co.	**$3,970,611**	**$368,376**	**$6,431,631**	**$42,209**	**$222,211**	**($421,931)**	**($217,822)**	**$21,166**	**($354,167)**
210 Wheeling Power Co. - Distribution	$4,373,458	$463,597	$7,084,167	$38,227	$242,623	($464,739)	($259,071)	$23,313	($419,647)
200 Wheeling Power Co. - Transmission	$140,497	$27,783	$227,578	$0	$7,354	($14,930)	($2,613)	$749	($9,440)
Wheeling Power Co.	**$4,513,955**	**$491,380**	**$7,311,745**	**$38,227**	**$249,977**	**($479,669)**	**($261,684)**	**$24,062**	**($429,087)**
103 American Electric Power Service Corporation	$255,543,697	$21,539,102	$413,931,988	$3,751,860	$14,423,312	($27,154,972)	($17,282,221)	$1,362,217	($24,899,804)
American Electric Power Service Corporation	**$255,543,697**	**$21,539,102**	**$413,931,988**	**$3,751,860**	**$14,423,312**	**($27,154,972)**	**($17,282,221)**	**$1,362,217**	**($24,899,804)**
143 AEP Pro Serv, Inc.	$76,920	$3,777	$124,596	$0	$4,353	($8,174)	($1,133)	$410	($4,544)
171 CSW Energy, Inc.	$1,508,629	$68,995	$2,443,691	$50,477	$88,455	($160,312)	($47,052)	$8,042	($60,390)
293 Elmwood	$2,235,602	$166,507	$3,621,248	$86,174	$129,902	($237,563)	($276,067)	$11,917	($285,637)
292 AEP River Operations LLC	$14,454,391	$852,623	$23,413,353	$658,914	$852,194	($1,535,975)	($1,245,634)	$77,051	($1,193,450)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$18,275,542**	**$1,091,902**	**$29,602,888**	**$795,565**	**$1,074,904**	**($1,942,024)**	**($1,569,886)**	**$97,420**	**($1,544,021)**
270 Cook Coal Terminal	$963,389	$96,532	$1,560,506	$9,757	$53,682	($102,373)	($67,747)	$5,135	($101,546)
AEP Generating Company	**$963,389**	**$96,532**	**$1,560,506**	**$9,757**	**$53,682**	**($102,373)**	**($67,747)**	**$5,135**	**($101,546)**
104 Cardinal Operating Company	$17,638,670	$1,637,510	$28,571,277	$228,544	$989,480	($1,874,347)	($1,116,823)	$94,026	($1,679,120)
181 Ohio Power Co. - Generation	$76,755,891	$7,514,390	$124,329,886	$496,787	$4,265,809	($8,156,352)	($4,359,566)	$409,159	($7,344,163)
AEP Generation Resources - FERC	**$94,394,561**	**$9,151,900**	**$152,901,163**	**$725,331**	**$5,255,289**	**($10,030,699)**	**($5,476,389)**	**$503,185**	**($9,023,283)**
290 Conesville Coal Preparation Company	$775,805	$92,909	$1,256,656	$0	$42,340	($82,440)	($51,555)	$4,136	($87,519)
AEP Generation Resources - SEC	**$95,170,366**	**$9,244,809**	**$154,157,819**	**$725,331**	**$5,297,629**	**($10,113,139)**	**($5,527,944)**	**$507,321**	**($9,110,802)**
Total	**$1,076,033,123**	**$99,619,966**	**$1,742,968,176**	**$13,268,254**	**$60,331,213**	**($114,343,075)**	**($69,056,806)**	**$5,735,963**	**($104,064,451)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2023 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations*		*Net Periodic Postretirement Benefit Cost*
							PSC	*(G)/L*	
140 Appalachian Power Co. - Distribution	$82,875,952	$8,390,768	$138,731,988	$798,260	$4,613,202	($9,110,139)	($4,467,940)	$398,620	($7,767,997)
215 Appalachian Power Co. - Generation	$70,542,045	$6,507,329	$118,085,378	$686,377	$3,945,196	($7,754,335)	($3,609,086)	$339,296	($6,392,552)
150 Appalachian Power Co. - Transmission	$10,234,462	$894,967	$17,132,199	$37,650	$570,194	($1,125,023)	($682,877)	$49,226	($1,150,830)
Appalachian Power Co. - FERC	**$163,652,459**	**$15,793,064**	**$273,949,565**	**$1,522,287**	**$9,128,592**	**($17,989,497)**	**($8,759,903)**	**$787,142**	**($15,311,379)**
225 Cedar Coal Co	$332,911	$57,385	$557,284	$0	$17,668	($36,595)	($4,704)	$1,601	($22,030)
Appalachian Power Co. - SEC	**$163,985,370**	**$15,850,449**	**$274,506,849**	**$1,522,287**	**$9,146,260**	**($18,026,092)**	**($8,764,607)**	**$788,743**	**($15,333,409)**
211 AEP Texas Central Company - Distribution	$61,878,247	$5,983,853	$103,582,427	$675,296	$3,457,020	($6,801,967)	($3,406,020)	$297,624	($5,778,047)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($9,150)	$0	($9,150)
169 AEP Texas Central Company - Transmission	$5,934,942	$538,524	$9,934,924	$77,626	$333,332	($652,399)	($345,328)	$28,546	($558,223)
AEP Texas Central Co.	**$67,813,189**	**$6,522,377**	**$113,517,351**	**$752,922**	**$3,790,352**	**($7,454,366)**	**($3,760,498)**	**$326,170**	**($6,345,420)**
170 Indiana Michigan Power Co. - Distribution	$39,830,854	$4,070,668	$66,675,718	$442,394	$2,219,463	($4,378,407)	($2,258,362)	$191,580	($3,783,332)
132 Indiana Michigan Power Co. - Generation	$24,562,682	$2,504,152	$41,117,232	$320,069	$1,371,603	($2,700,053)	($1,637,929)	$118,143	($2,528,167)
190 Indiana Michigan Power Co. - Nuclear	$45,492,263	$3,946,852	$76,152,755	$986,777	$2,582,939	($5,000,737)	($3,173,548)	$218,811	($4,385,758)
120 Indiana Michigan Power Co. - Transmission	$9,208,170	$819,673	$15,414,215	$89,484	$515,828	($1,012,208)	($519,191)	$44,290	($881,797)
280 Ind Mich River Transp Lakin	$10,970,934	$928,351	$18,365,032	$209,186	$621,904	($1,205,980)	($726,153)	$52,768	($1,048,275)
Indiana Michigan Power Co. - FERC	**$130,064,903**	**$12,269,696**	**$217,724,952**	**$2,047,910**	**$7,311,737**	**($14,297,385)**	**($8,315,183)**	**$625,592**	**($12,627,329)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$130,064,903**	**$12,269,696**	**$217,724,952**	**$2,047,910**	**$7,311,737**	**($14,297,385)**	**($8,315,183)**	**$625,592**	**($12,627,329)**
110 Kentucky Power Co. - Distribution	$15,879,464	$1,524,458	$26,581,771	$169,750	$887,268	($1,745,550)	($1,077,751)	$76,378	($1,689,905)
117 Kentucky Power Co. - Generation	$10,585,363	$973,232	$17,719,597	$61,363	$589,684	($1,163,596)	($534,759)	$50,914	($996,394)
180 Kentucky Power Co. - Transmission	$1,766,434	$136,300	$2,956,960	$22,040	$99,835	($194,175)	($179,802)	$8,496	($243,606)
600 Kentucky Power Co. - Kammer Actives	$1,197,772	$135,036	$2,005,036	$40,038	$67,932	($131,665)	($42,519)	$5,761	($60,453)
701 Kentucky Power Co. - Mitchell Actives	$6,395,734	$584,652	$10,706,277	$203,804	$366,057	($703,051)	($160,758)	$30,762	($263,186)
702 Kentucky Power Co. - Mitchell Inactives	$5,106,994	$455,467	$8,548,963	$0	$283,183	($561,386)	($200,742)	$24,564	($454,381)
Kentucky Power Co.	**$40,931,761**	**$3,809,145**	**$68,518,604**	**$496,995**	**$2,293,959**	**($4,499,423)**	**($2,196,331)**	**$196,875**	**($3,707,925)**
250 Ohio Power Co. - Distribution	$106,227,166	$10,579,677	$177,821,257	$1,070,630	$5,920,786	($11,677,022)	($5,113,012)	$510,936	($9,287,682)
160 Ohio Power Co. - Transmission	$12,723,863	$1,168,924	$21,299,385	$8,107	$705,033	($1,398,671)	($894,314)	$61,200	($1,518,645)
Ohio Power Co.	**$118,951,029**	**$11,748,601**	**$199,120,642**	**$1,078,737**	**$6,625,819**	**($13,075,693)**	**($6,007,326)**	**$572,136**	**($10,806,327)**
167 Public Service Co. of Oklahoma - Distribution	$37,927,265	$3,605,025	$63,489,164	$497,601	$2,125,570	($4,169,155)	($2,179,866)	$182,424	($3,543,426)
198 Public Service Co. of Oklahoma - Generation	$19,007,045	$1,842,995	$31,817,253	$318,431	$1,068,184	($2,089,349)	($1,343,022)	$91,421	($1,954,335)
114 Public Service Co. of Oklahoma - Transmission	$4,456,898	$402,028	$7,460,721	$66,672	$250,873	($489,925)	($277,975)	$21,437	($428,918)
Public Service Co. of Oklahoma	**$61,391,208**	**$5,850,048**	**$102,767,138**	**$882,704**	**$3,444,627**	**($6,748,429)**	**($3,800,863)**	**$295,282**	**($5,926,679)**
159 Southwestern Electric Power Co. - Distribution	$27,159,464	$2,497,908	$45,464,171	$384,903	$1,526,155	($2,985,504)	($1,712,430)	$130,633	($2,656,243)
168 Southwestern Electric Power Co. - Generation	$26,729,313	$2,494,676	$44,744,110	$462,969	$1,505,826	($2,938,220)	($1,924,757)	$128,564	($2,765,618)
161 Southwestern Electric Power Co. - Texas - Distribution	$12,728,265	$1,175,342	$21,306,754	$166,458	$714,289	($1,399,155)	($840,316)	$61,221	($1,297,503)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,276,547	$368,116	$7,158,818	$49,993	$240,414	($470,099)	($246,131)	$20,570	($405,253)
Southwestern Electric Power Co.	**$70,893,589**	**$6,536,042**	**$118,673,853**	**$1,064,323**	**$3,986,684**	**($7,792,978)**	**($4,723,634)**	**$340,988**	**($7,124,617)**
119 AEP Texas North Company - Distribution	$17,403,382	$1,730,432	$29,132,767	$207,193	$971,938	($1,913,067)	($1,133,906)	$83,707	($1,784,135)
166 AEP Texas North Company - Generation	$3,928,763	$468,087	$6,576,638	$0	$214,485	($431,869)	($38,821)	$18,897	($237,308)
192 AEP Texas North Company - Transmission	$2,359,307	$233,797	$3,949,413	$39,985	$132,474	($259,347)	($210,477)	$11,348	($286,017)
AEP Texas North Co.	**$23,691,452**	**$2,432,316**	**$39,658,818**	**$247,178**	**$1,318,897**	**($2,604,283)**	**($1,383,204)**	**$113,952**	**($2,307,460)**
230 Kingsport Power Co. - Distribution	$3,431,013	$308,750	$5,743,418	$40,725	$192,533	($377,154)	($154,125)	$16,503	($281,518)
260 Kingsport Power Co. - Transmission	$435,642	$40,007	$729,252	$2,487	$24,268	($47,888)	($34,972)	$2,095	($54,010)
Kingsport Power Co.	**$3,866,655**	**$348,757**	**$6,472,670**	**$43,212**	**$216,801**	**($425,042)**	**($189,097)**	**$18,598**	**($335,528)**
210 Wheeling Power Co. - Distribution	$4,190,711	$449,489	$7,015,131	$39,135	$232,480	($460,664)	($226,479)	$20,157	($395,371)
200 Wheeling Power Co. - Transmission	$120,068	$24,633	$200,990	$0	$6,260	($13,198)	($1,501)	$578	($7,861)
Wheeling Power Co.	**$4,310,779**	**$474,122**	**$7,216,121**	**$39,135**	**$238,740**	**($473,862)**	**($227,980)**	**$20,735**	**($403,232)**
103 American Electric Power Service Corporation	$252,179,767	$21,074,578	$422,141,760	$3,840,967	$14,246,650	($27,720,861)	($15,083,759)	$1,212,944	($23,504,059)
American Electric Power Service Corporation	**$252,179,767**	**$21,074,578**	**$422,141,760**	**$3,840,967**	**$14,246,650**	**($27,720,861)**	**($15,083,759)**	**$1,212,944**	**($23,504,059)**
143 AEP Pro Serv, Inc.	$77,496	$4,145	$129,726	$0	$4,376	($8,519)	($650)	$373	($4,420)
171 CSW Energy, Inc.	$1,578,566	$68,894	$2,642,475	$51,676	$92,584	($173,524)	($42,395)	$7,593	($64,066)
293 Elmwood	$2,285,171	$173,558	$3,825,311	$88,221	$132,694	($251,197)	($257,329)	$10,991	($276,620)
292 AEP River Operations LLC	$15,112,876	$887,302	$25,298,525	$674,563	$890,302	($1,661,283)	($1,149,926)	$72,691	($1,173,653)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$19,054,109**	**$1,133,899**	**$31,896,037**	**$814,460**	**$1,119,956**	**($2,094,523)**	**($1,450,300)**	**$91,648**	**($1,518,759)**
270 Cook Coal Terminal	$930,296	$81,805	$1,557,289	$9,989	$52,198	($102,263)	($60,465)	$4,475	($96,066)
AEP Generating Company	**$930,296**	**$81,805**	**$1,557,289**	**$9,989**	**$52,198**	**($102,263)**	**($60,465)**	**$4,475**	**($96,066)**
104 Cardinal Operating Company	$17,219,184	$1,576,550	$28,824,425	$233,972	$967,207	($1,892,819)	($982,050)	$82,822	($1,590,868)
181 Ohio Power Co. - Generation	$74,004,097	$7,246,858	$123,880,755	$508,586	$4,114,539	($8,134,901)	($3,691,307)	$355,948	($6,847,135)
AEP Generation Resources - FERC	**$91,223,281**	**$8,823,408**	**$152,705,180**	**$742,558**	**$5,081,746**	**($10,027,720)**	**($4,673,357)**	**$438,770**	**($8,438,003)**
290 Conesville Coal Preparation Company	$725,236	$81,658	$1,214,024	$0	$39,729	($79,722)	($44,779)	$3,488	($81,284)
AEP Generation Resources - SEC	**$91,948,517**	**$8,905,066**	**$153,919,204**	**$742,558**	**$5,121,475**	**($10,107,442)**	**($4,718,136)**	**$442,258**	**($8,519,287)**
Total	**$1,050,012,624**	**$97,036,901**	**$1,757,691,288**	**$13,583,377**	**$58,914,155**	**($115,422,642)**	**($60,681,383)**	**$5,050,396**	**($98,556,097)**

AMERICAN ELECTRIC POWER
NON-UMWA POSTRETIREMENT WELFARE PLAN
ESTIMATED 2024 NET PERIODIC POSTRETIREMENT BENEFIT COST

Location	*Accumulated Postretirement Benefit Obligation*	*Expected Net Benefit Payments*	*Fair Value of Assets*	*Service Cost*	*Interest Cost*	*Expected Return on Assets*	*Amortizations PSC*	*Amortizations (G)/L*	*Net Periodic Postretirement Benefit Cost*
140 Appalachian Power Co. - Distribution	$79,896,646	$8,018,076	$138,377,668	$817,219	$4,452,157	($9,097,423)	($750,141)	$347,030	($4,231,158)
215 Appalachian Power Co. - Generation	$68,666,289	$6,337,002	$118,927,157	$702,678	$3,842,217	($7,818,679)	($596,598)	$298,251	($3,572,131)
150 Appalachian Power Co. - Transmission	$9,947,339	$890,041	$17,228,377	$38,544	$553,734	($1,132,653)	($114,808)	$43,206	($611,977)
Appalachian Power Co. - FERC	**$158,510,274**	**$15,245,119**	**$274,533,202**	**$1,558,441**	**$8,848,108**	**($18,048,755)**	**($1,461,547)**	**$688,487**	**($8,415,266)**
225 Cedar Coal Co	$293,194	$51,066	$507,800	$0	$15,545	($33,385)	$0	$1,273	($16,567)
Appalachian Power Co. - SEC	**$158,803,468**	**$15,296,185**	**$275,041,002**	**$1,558,441**	**$8,863,653**	**($18,082,140)**	**($1,461,547)**	**$689,760**	**($8,431,833)**
211 AEP Texas Central Company - Distribution	$60,026,710	$5,811,799	$103,963,765	$691,334	$3,355,480	($6,834,935)	($572,702)	$260,725	($3,100,098)
147 AEP Texas Central Company - Generation	$0	$0	$0	$0	$0	$0	($170)	$0	($170)
169 AEP Texas Central Company - Transmission	$5,807,376	$525,893	$10,058,134	$79,470	$326,401	($661,256)	($58,681)	$25,224	($288,842)
AEP Texas Central Co.	**$65,834,086**	**$6,337,692**	**$114,021,899**	**$770,804**	**$3,681,881**	**($7,496,191)**	**($631,553)**	**$285,949**	**($3,389,110)**
170 Indiana Michigan Power Co. - Distribution	$38,422,043	$3,856,057	$66,545,381	$452,901	$2,144,497	($4,374,922)	($374,954)	$166,886	($1,985,592)
132 Indiana Michigan Power Co. - Generation	$23,750,202	$2,371,427	$41,134,362	$327,671	$1,328,715	($2,704,314)	($282,661)	$103,159	($1,227,430)
190 Indiana Michigan Power Co. - Nuclear	$45,115,127	$3,857,975	$78,137,524	$1,010,213	$2,564,965	($5,137,029)	($560,473)	$195,957	($1,926,367)
120 Indiana Michigan Power Co. - Transmission	$8,993,809	$820,972	$15,576,903	$91,609	$503,482	($1,024,079)	($86,552)	$39,064	($476,476)
280 Ind Mich River Transp Lakin	$10,873,673	$888,770	$18,832,749	$214,154	$617,683	($1,238,130)	($126,462)	$47,230	($485,525)
Indiana Michigan Power Co. - FERC	**$127,154,854**	**$11,795,201**	**$220,226,919**	**$2,096,548**	**$7,159,342**	**($14,478,474)**	**($1,431,102)**	**$552,296**	**($6,101,390)**
202 Price River Coal	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indiana Michigan Power Co. - SEC	**$127,154,854**	**$11,795,201**	**$220,226,919**	**$2,096,548**	**$7,159,342**	**($14,478,474)**	**($1,431,102)**	**$552,296**	**($6,101,390)**
110 Kentucky Power Co. - Distribution	$15,412,024	$1,456,837	$26,692,985	$173,782	$862,324	($1,754,888)	($186,335)	$66,942	($838,175)
117 Kentucky Power Co. - Generation	$10,263,178	$947,994	$17,775,397	$62,820	$571,804	($1,168,616)	($89,627)	$44,578	($579,041)
180 Kentucky Power Co. - Transmission	$1,752,009	$137,044	$3,034,407	$22,563	$99,007	($199,492)	($32,292)	$7,610	($102,604)
600 Kentucky Power Co. - Kammer Actives	$1,170,706	$127,258	$2,027,614	$40,989	$66,640	($133,302)	($12,715)	$5,085	($33,303)
701 Kentucky Power Co. - Mitchell Actives	$6,380,943	$575,727	$11,051,528	$208,644	$365,735	($726,565)	($60,305)	$27,716	($184,775)
702 Kentucky Power Co. - Mitchell Inactives	$4,934,710	$451,697	$8,546,712	$0	$273,299	($561,890)	($108,102)	$21,434	($375,259)
Kentucky Power Co.	**$39,913,570**	**$3,696,557**	**$69,128,643**	**$508,798**	**$2,238,809**	**($4,544,753)**	**($489,376)**	**$173,365**	**($2,113,157)**
250 Ohio Power Co. - Distribution	$102,638,905	$10,119,543	$177,766,315	$1,096,057	$5,727,297	($11,686,967)	($841,947)	$445,810	($5,259,750)
160 Ohio Power Co. - Transmission	$12,268,079	$1,158,876	$21,247,803	$8,300	$678,896	($1,396,903)	($147,780)	$53,286	($804,201)
Ohio Power Co.	**$114,906,984**	**$11,278,419**	**$199,014,118**	**$1,104,357**	**$6,406,193**	**($13,083,870)**	**($989,727)**	**$499,096**	**($6,063,951)**
167 Public Service Co. of Oklahoma - Distribution	$36,945,411	$3,490,866	$63,987,915	$509,419	$2,072,572	($4,206,785)	($369,064)	$160,472	($1,833,386)
198 Public Service Co. of Oklahoma - Generation	$18,550,665	$1,753,216	$32,128,980	$325,994	$1,044,720	($2,112,269)	($235,833)	$80,575	($896,813)
114 Public Service Co. of Oklahoma - Transmission	$4,372,415	$396,267	$7,572,841	$68,255	$246,229	($497,865)	($47,953)	$18,992	($212,342)
Public Service Co. of Oklahoma	**$59,868,491**	**$5,640,349**	**$103,689,736**	**$903,668**	**$3,363,521**	**($6,816,919)**	**($652,850)**	**$260,039**	**($2,942,541)**
159 Southwestern Electric Power Co. - Distribution	$26,572,614	$2,433,963	$46,022,662	$394,044	$1,494,476	($3,025,688)	($331,569)	$115,418	($1,353,319)
168 Southwestern Electric Power Co. - Generation	$26,203,432	$2,492,229	$45,383,254	$473,965	$1,476,033	($2,983,651)	($339,735)	$113,814	($1,259,574)
161 Southwestern Electric Power Co. - Texas - Distribution	$12,433,670	$1,122,075	$21,534,599	$170,411	$698,955	($1,415,758)	($145,622)	$54,005	($638,009)
111 Southwestern Electric Power Co. - Texas - Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0
194 Southwestern Electric Power Co. - Transmission	$4,198,838	$380,391	$7,272,213	$51,180	$235,625	($478,100)	($41,708)	$18,238	($214,765)
Southwestern Electric Power Co.	**$69,408,554**	**$6,428,658**	**$120,212,728**	**$1,089,600**	**$3,905,089**	**($7,903,197)**	**($858,634)**	**$301,475**	**($3,465,667)**
119 AEP Texas North Company - Distribution	$16,852,081	$1,651,126	$29,187,103	$212,114	$942,516	($1,918,860)	($194,782)	$73,197	($885,815)
166 AEP Texas North Company - Generation	$3,675,161	$451,112	$6,365,226	$0	$200,261	($418,472)	$0	$15,963	($202,248)
192 AEP Texas North Company - Transmission	$2,297,969	$218,899	$3,979,987	$40,935	$129,398	($261,658)	($37,182)	$9,981	($118,526)
AEP Texas North Co.	**$22,825,211**	**$2,321,137**	**$39,532,316**	**$253,049**	**$1,272,175**	**($2,598,990)**	**($231,964)**	**$99,141**	**($1,206,589)**
230 Kingsport Power Co. - Distribution	$3,355,521	$309,571	$5,811,623	$41,692	$188,187	($382,076)	($25,400)	$14,575	($163,022)
260 Kingsport Power Co. - Transmission	$422,390	$41,024	$731,562	$2,546	$23,473	($48,095)	($5,843)	$1,835	($26,084)
Kingsport Power Co.	**$3,777,911**	**$350,595**	**$6,543,185**	**$44,238**	**$211,660**	**($430,171)**	**($31,243)**	**$16,410**	**($189,106)**
210 Wheeling Power Co. - Distribution	$4,012,837	$424,989	$6,950,067	$40,064	$222,917	($456,921)	($37,583)	$17,430	($214,093)
200 Wheeling Power Co. - Transmission	$101,695	$21,574	$176,132	$0	$5,281	($11,580)	$0	$442	($5,857)
Wheeling Power Co.	**$4,114,532**	**$446,563**	**$7,126,199**	**$40,064**	**$228,198**	**($468,501)**	**($37,583)**	**$17,872**	**($219,950)**
103 American Electric Power Service Corporation	$249,192,806	$20,592,671	$431,591,576	$3,932,189	$14,092,479	($28,374,311)	($2,589,281)	$1,082,364	($11,856,560)
American Electric Power Service Corporation	**$249,192,806**	**$20,592,671**	**$431,591,576**	**$3,932,189**	**$14,092,479**	**($28,374,311)**	**($2,589,281)**	**$1,082,364**	**($11,856,560)**
143 AEP Pro Serv, Inc.	$77,727	$4,242	$134,620	$0	$4,387	($8,850)	$0	$338	($4,125)
171 CSW Energy, Inc.	$1,653,932	$75,790	$2,864,541	$52,903	$96,829	($188,325)	($7,642)	$7,184	($39,051)
293 Elmwood	$2,332,528	$180,377	$4,039,841	$90,316	$135,368	($265,593)	($47,195)	$10,131	($76,973)
292 AEP River Operations LLC	$15,790,439	$932,382	$27,348,384	$690,584	$929,241	($1,797,977)	($212,552)	$68,586	($322,118)
189 Central Coal Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous	**$19,854,626**	**$1,192,791**	**$34,387,386**	**$833,803**	**$1,165,825**	**($2,260,745)**	**($267,389)**	**$86,239**	**($442,267)**
270 Cook Coal Terminal	$910,678	$76,055	$1,577,256	$10,226	$51,238	($103,694)	($10,620)	$3,956	($48,894)
AEP Generating Company	**$910,678**	**$76,055**	**$1,577,256**	**$10,226**	**$51,238**	**($103,694)**	**($10,620)**	**$3,956**	**($48,894)**
104 Cardinal Operating Company	$16,843,813	$1,545,505	$29,172,784	$239,529	$946,646	($1,917,919)	($166,189)	$73,161	($824,772)
181 Ohio Power Co. - Generation	$71,380,364	$6,912,773	$123,627,822	$520,665	$3,972,615	($8,127,717)	($484,947)	$310,039	($3,809,345)
AEP Generation Resources - FERC	**$88,224,177**	**$8,458,278**	**$152,800,606**	**$760,194**	**$4,919,261**	**($10,045,636)**	**($651,136)**	**$383,200**	**($4,634,117)**
290 Conesville Coal Preparation Company	$683,307	$61,883	$1,183,459	$0	$37,862	($77,805)	($7,443)	$2,968	($44,418)
AEP Generation Resources - SEC	**$88,907,484**	**$8,520,161**	**$153,984,065**	**$760,194**	**$4,957,123**	**($10,123,441)**	**($658,579)**	**$386,168**	**($4,678,535)**
Total	**$1,025,473,255**	**$93,973,034**	**$1,776,077,028**	**$13,905,979**	**$57,597,186**	**($116,765,397)**	**($10,341,448)**	**$4,454,130**	**($51,149,550)**

Effect of Additional Pension Contributions Recorded As Prepaid Pension Asset in Reducing Pension Cost
Kentucky Power Company

	Plan Contribution	Less Qualified FAS 87 Cost	Additional Contribution	Investment Return Rate	Investment Return Amount	Balance of Plan Assets
					FAS 87 Savings	
2002 Contributions	-	(2,471,778)	2,471,778			
2003 Contributions	2,497,386	(1,058,869)	3,556,255			
2004 Contributions	551,238	671,532	(120,294)			
2005 Contributions	29,430,947	2,135,256	27,295,691			27,295,691
2006 Return on 2005 Balance				8.50%	**2,320,134**	29,615,825
2006 Contributions	-	1,928,538	(1,928,538)			27,687,287
2007 Return on 2006 Balance				8.50%	**2,517,345**	30,204,632
2007 Contributions	-	1,268,242	(1,268,242)			28,936,390
2008 Return on 2007 Balance				8.00%	**2,416,371**	31,352,760
2008 Contributions	-	1,243,528	(1,243,528)			30,109,232
2009 Return on 2008 Balance				8.00%	**2,508,221**	32,617,453
2009 Contributions	-	3,172,307	(3,172,307)			29,445,146
2010 Return on 2009 Balance				8.00%	**2,609,396**	32,054,542
2010 Contributions	13,012,606	4,704,090	8,308,516			40,363,058
2011 Return on 2010 Balance				7.75%	**3,128,137**	43,491,196
2011 Contributions	22,146,267	4,103,290	18,042,977			61,534,173
2012 Return on 2011 Balance				7.25%	**4,461,228**	65,995,400
2012 Contributions	8,482,245	4,179,727	4,302,518			70,297,918
2013 Return on 2012 Balance				6.50%	**4,569,365**	74,867,283
2013 Contributions	-	5,607,308	(5,607,308)			69,259,975
2014 Return on 2013 Balance				6.00%	**4,155,598**	73,415,573
2014 Contributions Through September 30	1,923,000	3,892,737	(1,969,737)			71,445,836
Total Additional Contributions Above	78,043,689	29,375,908	48,667,781			
Cumulative Prior Years			5,042,187			
Prepaid Pension Balance at September 2014			53,709,968			

	Calendar Year 2014
Actual Total Pension Cost (Qualified and SERP)	4,311,543
Prepaid Contribution Savings Above	4,155,598
Pension Cost Without Contribution Savings	8,467,141

Effect of Additional Pension Contributions Recorded As Prepaid Pension Asset in Reducing Pension Cost
Kentucky Power Company Through December 2013 - Without Mitchell Plant

	Plan Contribution	Less Qualified FAS 87 Cost	Additional Contribution	Investment Return Rate	Investment Return Amount	Balance of Plan Assets
					FAS 87 Savings	
2002 Contributions	-	(1,405,859)	1,405,859			
2003 Contributions	1,613,800	(582,318)	2,196,118			
2004 Contributions	451,453	554,622	(103,169)			
2005 Contributions	15,775,528	1,486,940	14,288,588			14,288,588
2006 Return on 2005 Balance				8.50%	**1,214,530**	15,503,118
2006 Contributions	-	1,427,413	(1,427,413)			14,075,705
2007 Return on 2006 Balance				8.50%	**1,317,765**	15,393,470
2007 Contributions	-	1,014,052	(1,014,052)			14,379,418
2008 Return on 2007 Balance				8.00%	**1,231,478**	15,610,896
2008 Contributions	-	990,244	(990,244)			14,620,652
2009 Return on 2008 Balance				8.00%	**1,248,872**	15,869,523
2009 Contributions	-	2,215,416	(2,215,416)			13,654,107
2010 Return on 2009 Balance				8.00%	**1,269,562**	14,923,669
2010 Contributions	6,183,898	2,995,603	3,188,295			18,111,964
2011 Return on 2010 Balance				7.75%	**1,403,677**	19,515,641
2011 Contributions	10,535,000	2,894,613	7,640,387			27,156,028
2012 Return on 2011 Balance				7.25%	**1,968,812**	29,124,840
2012 Contributions	4,902,000	3,244,941	1,657,059			30,781,899
2013 Return on 2012 Balance				6.50%	**2,000,823**	32,782,723
2013 Contributions	-	4,057,917	(4,057,917)			28,724,806
2014 Return on 2013 Balance				6.00%	**1,723,488**	30,448,294
Total Additional Contributions Above	39,461,679	18,893,584	20,568,095			
Cumulative Prior Years			2,696,523			
Prepaid Pension Balance at December 2013			23,264,618			

Effect of Additional Pension Contributions Recorded As Prepaid Pension Asset in Reducing Pension Cost
Kentucky Power Company Through December 2013 - Mitchell Plant

	Plan Contribution	Less Qualified FAS 87 Cost	Additional Contribution	Investment Return Rate	Investment Return Amount	Balance of Plan Assets
					FAS 87 Savings	
2002 Contributions	-	(1,065,919)	1,065,919			
2003 Contributions	883,586	(476,551)	1,360,137			
2004 Contributions	99,785	116,910	(17,125)			
2005 Contributions	13,655,419	648,316	13,007,103			13,007,103
2006 Return on 2005 Balance				8.50%	**1,105,604**	14,112,707
2006 Contributions	-	501,125	(501,125)			13,611,582
2007 Return on 2006 Balance				8.50%	**1,199,580**	14,811,162
2007 Contributions	-	254,190	(254,190)			14,556,972
2008 Return on 2007 Balance				8.00%	**1,184,893**	15,741,865
2008 Contributions	-	253,284	(253,284)			15,488,581
2009 Return on 2008 Balance				8.00%	**1,259,349**	16,747,930
2009 Contributions	-	956,891	(956,891)			15,791,039
2010 Return on 2009 Balance				8.00%	**1,339,834**	17,130,873
2010 Contributions	6,828,708	1,708,487	5,120,221			22,251,094
2011 Return on 2010 Balance				7.75%	**1,724,460**	23,975,554
2011 Contributions	11,611,267	1,208,677	10,402,590			34,378,144
2012 Return on 2011 Balance				7.25%	**2,492,415**	36,870,560
2012 Contributions	3,580,245	934,786	2,645,459			39,516,019
2013 Return on 2012 Balance				6.50%	**2,568,541**	42,084,560
2013 Contributions	-	1,549,391	(1,549,391)			40,535,169
2014 Return on 2013 Balance				6.00%	**2,432,110**	42,967,279
Total Additional Contributions Above	36,659,010	6,589,587	30,069,423			
Cumulative Prior Years			2,345,664			
Prepaid Pension Balance at December 2013			32,415,087			

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)	**Case No. 2014-00396**

DIRECT TESTIMONY OF

JOHN M. MCMANUS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, John M. McManus being duly sworn, deposes and says he is the Vice President of Environmental Services for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

JOHN M. MCMANUS

STATE OF OHIO	)	
	)	CASE NO. 2014-00396
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 15 day of December, 2014.

Notary Public

My Commission Expires: 12-31-2014

NOTARIAL SEAL
STATE OF OHIO

PATRICK R OTT
NOTARY PUBLIC - OHIO
MY COMMISSION EXPIRES
DECEMBER 31, 2014

DIRECT TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is John M. McManus. I am employed by American Electric Power Service Corporation as Vice President - Environmental Services. American Electric Power Service Corporation ("AEPSC") is a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science Degree in Environmental Engineering from Rensselaer Polytechnic Institute in 1976 and undertook graduate studies there from 1976-77. I joined AEPSC's Environmental Engineering Division in September 1977. After holding various positions in the environmental division over the years, I was appointed as Manager, Environmental Services in December 2002 and remained in that position until April 2003. I was appointed to my current position as Vice President - Environmental Services in April 2003. I am also a registered professional engineer in the State of Ohio.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT-ENVIRONMENTAL SERVICES?

A. I am responsible for oversight of environmental support for all generation and energy delivery facilities owned by AEP operating companies. Environmental Services provides permitting and compliance support, guidance, procedures, recommendations and training for AEP's operating companies in order to maintain and improve their environmental programs and enhance compliance with environmental laws, regulations, and policies. As part of this effort, Environmental Services is also involved in the development process for environmental regulations, coordinating with operating company staffs to support AEP's corporate strategies and values concerning the environment.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified before the Kentucky Public Service Commission ("Commission") on a number of occasions. In addition, I have testified before the Virginia State Corporation Commission, Indiana Utility Regulatory Commission, Public Service Commission of West Virginia, Public Utilities Commission of Ohio, and I have submitted testimony before the Public Utility Commission of Texas.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe the applicable environmental rules that affect the generating units owned by Kentucky Power. In addition, my testimony addresses anticipated rules that will require further environmental projects to be performed at Kentucky Power's Big Sandy and Mitchell Plants as well as the Rockport Plant in Indiana. Kentucky Power purchases 393 megawatts ("MW") of the output of the Rockport Plant, which is operated by Indiana Michigan Power ("I&M"). Similar to Kentucky Power, I&M is a subsidiary of AEP. Finally, as part of my testimony I address the environmental regulatory requirements which necessitate the projects identified in the Environmental Compliance Plan, as presented by Company Witness Elliott.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring Exhibits No. JMM-1 and JMM-2. Exhibit JMM-1 is a copy of AEP's New Source Review (NSR) Consent Decree (the "Consent Decree"), a document entered into between AEP, the United States Department of Justice ("DOJ"), various states in the northeastern United States, and other involved parties. Exhibit JMM-2 is a copy of the Third Joint Modification to the Consent Decree ("Modified Consent Decree").

IV. CURRENT EPA ENVIRONMENTAL REGULATIONS

Q. PLEASE DESCRIBE THE REGULATORY PROGRAMS THAT DRIVE THE NEED FOR THE ENVIRONMENTAL CONTROLS CURRENTLY INSTALLED AT THE BIG SANDY, MITCHELL, AND ROCKPORT PLANTS.

A. The following major known, existing federal rulemakings, and previously-established requirements, create the need for the environmental controls currently installed on the Big Sandy, Mitchell, and Rockport generating plants:

1. **Clean Air Interstate Rule ("CAIR")** - The United States Environmental Protection Agency ("EPA") promulgated the CAIR in order to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) primarily from the power generation sector in two phases, with compliance deadlines in 2009/2010 and 2015. These emissions reductions are implemented through an interstate cap and trade program. The cap and trade program provides emission allowances for SO_2 and NO_x for sources and for states. Electric generating units' compliance with the annual NO_x reduction requirements began January 1, 2009. The ozone season (summer) NO_x reduction requirements began May 1, 2009. Electric generating units' compliance with the annual SO_2 reduction requirements began January 1, 2010. As of these dates, operators of electric generating units were required to hold enough CAIR allowances in their respective accounts to cover every ton of NO_x or SO_2 emitted.

   In 2008 the D.C. Circuit Court of Appeals remanded the CAIR back to the EPA for rewriting. This remand was ordered without vacating the rule, so that CAIR would remain in place while a replacement was created.

2. **Cross-State Air Pollution Rule ("CSAPR") –** The CSAPR was created to serve as the replacement for the CAIR, and was initially proposed by the EPA in August 2010 as the Clean Air Transport Rule. The CSAPR addresses National Ambient Air Quality Standards ("NAAQS") for ozone and particulate matter, and is focused on the reduction of emissions of SO_2 and NO_X from electric generating units in 28 eastern, southern and mid-western states—including Kentucky, Indiana and West Virginia.[1] Along with other requirements, the final CSAPR established state-specific annual emission "budgets" for SO_2 and annual and seasonal budgets for NO_X. Based on this budget, each

[1] Final CSAPR issued by the USEPA on July 6, 2011 and published in the Federal Register on August 8, 2011.

emitting unit within affected states was allocated a specified number of NO_x and SO_2 allowances for the applicable compliance period, whether annual or ozone season. Allowance trading within and between states is allowed on a regional basis.

The CSAPR was stayed on December 30, 2011 by the D.C. Circuit Court of Appeals, and was subsequently vacated by the same Court. EPA and DOJ appealed the ruling to the Supreme Court. On April 29, 2014, the Supreme Court issued its decision reversing the decision of the lower court, and remanded the case to the DC Circuit Court for additional proceedings. The CAIR remained in effect throughout this process. On June 26, 2014, EPA filed a motion to lift the stay of CSAPR which the D.C Circuit Court granted on October 23, 2014. While legal challenges associated with the final outcome of this rule are still pending, the Court's decision to lift the stay will result in the application of CSAPR Phase 1 emission budgets starting in 2015. The CSAPR Phase 2 emission budgets will be applicable beginning in 2017.

3. **Clean Water Act 316(b) Rule –** A final rule under Section 316(b) of the Clean Water Act was issued by EPA on August 15, 2014, with an effective date of October 14, 2014 affecting all existing power plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with a standard that addresses impingement of aquatic organisms on cooling water intake screens and requires site-specific studies to determine appropriate compliance measures to address entrainment of organisms in cooling water systems for those facilities withdrawing more than 125 million gallons per day. The overall goal of the rule is to decrease impacts on fish and other aquatic organisms from operation of cooling water systems. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, such as Big Sandy, Mitchell, and

Rockport units, may not be required to make any technology changes. This determination would be made by the applicable state environmental agency during the plants' next National Pollutant Discharge Elimination System ("NPDES") permit renewal cycle.

4. **Mercury and Air Toxics Standard ("MATS") -** The Mercury and Air Toxics Standard Rule creates additional environmental requirements at coal- and oil-fired electric generating units for emissions of hazardous air pollutants ("HAPs"). This rule replaces the former Clean Air Mercury Rule that was vacated in 2008 by the D.C. Circuit Court of Appeals. The final MATS Rule became effective on April 16, 2012, with compliance required within three years of that date (with the possibility of a compliance extension in certain circumstances). The emission parameters regulated by this rule are: 1) mercury; 2) several non-mercury metals such as arsenic, lead, cadmium and selenium; 3) various acid gases including hydrochloric acid (HCl); and 4) many organic HAPs. The rule includes stringent emission rate limits for these parameters. In addition, the rule contains alternative stringent emission rate limits for surrogates representing two classes of HAPs, acid gases and non-mercury particulate metal HAPs. The surrogates for the non-mercury particulate metal and acid gas HAPs are filterable particulate matter (PM) and HCl respectively. The rule regulates organic HAPs through work practice standards. Recently, on November 25, 2014, the US Supreme Court indicated that it will review whether EPA should have considered the cost of complying with MATS in developing the rule. While MATS is being reviewed by the US Supreme Court the rule will remain in effect.

5. **NSR Consent Decree -** In December 2007, AEP, Kentucky Power and its affiliated eastern Operating Companies entered into a Consent Decree that settled outstanding litigation with the DOJ, EPA, numerous states, and other litigants that stemmed from differences in interpretation of various New Source Review requirements associated

with coal unit maintenance practices. The AEP Companies admitted no violations of law and the claims against them were released. There have been three modifications to the initial Consent Decree, but only the third modification is relevant to Kentucky Power. For the Big Sandy, Mitchell, and Rockport plants, the Consent Decree, as modified, called for the following schedule of NOx and SO_2 controls:

- Big Sandy Unit 2: The initial requirement to install a flue gas desulfurization system ("FGD") for SO_2 emission reduction by December 31, 2015 was revised to Retrofit, Retire, Re-Power or Refuel by the same date in the Third Modification to the Consent Decree
- Big Sandy Unit 2: Continuously operate the existing selective catalytic reduction ("SCR") system to minimize NOx emissions starting January 1, 2009
- Big Sandy Unit 1: Install Low-NO_X Burner technology *and* limit the sulfur content of its coal to no greater than 1.75 lb. per million British thermal units (MMBtu), on an annual average basis, by the effective date of the Consent Decree.
- Mitchell Units 1 and 2: install and continuously operate SCR systems by January 1, 2009.
- Mitchell Units 1 and 2: install and continuously operate FGD systems by December 31, 2007.
- Rockport Units 1 and 2: install and continuously operate Dry Sorbent Injection ("DSI") by April 16, 2015[2]
- Rockport Units 1 and 2: install and continuously operate SCR systems on the generating units by December 31, 2017 and December 31, 2019, respectively
- Rockport Units 1 and 2: Retrofit, Retire, Re-Power, or Refuel by December 31, 2025 and December 31, 2028, respectively.

Q. WHAT ARE THE IMPLICATIONS OF THE MATS RULE FOR THE BIG SANDY, MITCHELL, AND ROCKPORT PLANTS?

A. The MATS Rule establishes stringent unit-specific emission limits that are applicable to all three plants. To comply with the MATS limits, the Big Sandy units are required to install additional emission controls, switch fuels, or be

[2] The Third Joint Modification to the Consent Decree was filed by AEP, the Department of Justice, the EPA and other parties on February 22, 2013 in United States District Court for the Southern District of Ohio, Eastern Division. The Third Joint Modification was entered on May 14, 2013.

retired. Kentucky Power elected to retire Big Sandy Unit 2 and to refuel Big Sandy Unit 1 with natural gas. The Commission approved the Company's decisions in Case Nos. 2012-00578 and 2013-00430, respectively. The Mitchell units are expected to be able to achieve the MATS limits without any significant upgrades to existing emission control equipment, or installations of new emission control equipment. The Rockport units are installing DSI control technology and upgrading the activated carbon injection systems on both units to ensure compliance with the MATS limits.

Q. WHAT IS THE COMPLIANE TIMELINE FOR THE MATS RULE?

A. The initial MATS compliance date is April 16, 2015, three years after the effective date of the rule. However, a one-year administrative extension of the initial compliance date (a fourth year) can be granted by a state's Department of Environmental Protection for units undertaking major retrofit or replacement projects, or for units that will retire but are required for reliability purposes. An additional one year extension (a fifth year) may also be available for units identified as "critical for reliability purposes" via an Enforcement Order from EPA. Kentucky Power requested and was granted a one year extension at Big Sandy Unit 1 to complete the project to refuel the unit to natural gas and an extension until June 1, 2015 at Big Sandy Unit 2 to ensure consistency with the PJM capacity planning year. No extensions were necessary for the Mitchell and Rockport Plants as these units are expected to meet the compliance timeline for the MATS Rule.

Q. WHAT ARE THE IMPLICATIONS FOR KENTUCKY POWER OF THE DC CIRCUIT COURT'S DECISION TO GRANT EPA'S MOTION TO LIFT THE STAY OF CSAPR?

A. The DC Circuit Court granted the EPA's motion to lift the stay of CSAPR and implement the rule's Phase 1 emission budgets beginning in 2015, with the Phase 2 emission budgets beginning in 2017. Similar to Kentucky Power's compliance with the Title IV and CAIR allowance programs, to comply with CSAPR it will need to surrender a sufficient number of allowances relative to its generating facilities' emissions. Dependent upon Kentucky Power's actual generation this may require the purchase of allowances in addition to those already held.

Q. DO AEP AND ITS SUBSIDIARIES HAVE PLANS IN PLACE TO FULFILL THE REQUIREMENTS OF THE 2007 AEP NSR CONSENT DECREE AND SUBSEQUENT MODIFICATIONS?

A. Yes. The planned retirement of Big Sandy Unit 2 and the fuel-conversion to natural gas at Big Sandy Unit 1 will meet the requirements of the Consent Decree. With respect to the Mitchell Plant, the existing environmental controls in place meet the requirements of the Consent Decree, included in Exhibit JMM-1 to my testimony, and no additional environmental controls are necessary. Finally, the Rockport Plant's retrofit with DSI technology is consistent with the Third Joint Modification to the Consent Decree, included as Exhibit JJM-2 to my testimony. In addition to the current DSI installation, the Consent Decree as modified requires the installation of SCR technology and provides the option to retire, re-power, refuel, or retrofit with FGD technology in future years for both of the Rockport Units.

V. FUTURE EPA ENVIRONMENTAL REGULATIONS

Q. PLEASE DISCUSS OTHER PROPOSED AND EMERGING ENVIRONMENTAL REGULATIONS THAT MAY CREATE THE NEED FOR ADDITIONAL ENVIRONMENTAL CONTROL RETROFITS AT KENTUCKY POWER'S GENERATING PLANTS.

A. The following proposed and anticipated environmental regulations have the potential to establish more stringent requirements and the subsequent need for upgrades to and/or new installation of environmental control systems at the Big Sandy, Mitchell, and Rockport generating plants:

1. **New 1-hour SO_2 NAAQS –** In 2010, the EPA revised the NAAQS for SO_2, establishing a new 1-hour standard, which is more stringent than the prior standards. In April 2014, EPA proposed a Data Requirements Rule that provided guidance on the schedule for final designations from EPA for areas that have not been designated as non-attainment based on monitoring data. According to this proposal, the designation process will not be completed until the end of 2017 at the earliest and may extend to 2020 for those states utilizing air quality monitoring as the basis for their designations. Given that State Implementation Plans ("SIPs") would then have to be developed and approved, the timing and extent of any potential emission reductions at Kentucky Power's plants from the revised SO2 NAAQS rule is uncertain and, based on the proposed Data Requirements Rule, would not be expected until late this decade at the earliest.
2. **Interstate Transport Rule for the 2008 Ozone NAAQS –** EPA has indicated it will propose regulations to address ozone nonattainment areas based on the 2008 ozone NAAQS but the schedule is uncertain. Regulation of NOx emissions, which are a precursor to ozone formation,

will be a component of this proposal.

3. **Revision to the 2008 Ozone NAAQS –** On November 26, 2014, EPA announced its intent to propose a revision to the 2008 ozone NAAQS with a final rule anticipated by October 1, 2015.
4. **Section 176(A) Petition –** On December 13, 2013, eight Northeast and Mid-Atlantic states filed a petition with USEPA asking the agency to add nine upwind states to the Ozone Transport Region (OTR). Kentucky, Indiana, and West Virginia were included in this list of nine states. If added to the OTR, these states would be required to take additional steps to reduce their air pollution, including NO_X emissions, that has been found to significantly affect downwind states. EPA has 18 months to issue a decision on this petition.
5. **Revisions to the NAAQS for particulate matter with a diameter less than 2.5 microns ($PM_{2.5}$) –** EPA lowered the $PM_{2.5}$ NAAQS in 2013. While implementation of this revised standard is just underway, there is the potential for future SO_2 and NO_X reduction requirements associated with this revised NAAQS.
6. **Steam Electric Effluent Limitations Guidelines ("ELG") –** EPA proposed an update to the ELG (40 CFR 423) for the steam electric power generating category on June 7, 2013. The proposed ELG would require more stringent controls on certain discharges from certain electric generating units, and will set technology-based limits for waste water discharges from power plants with a main focus on process and wastewater from FGD, fly ash sluice water, bottom ash sluice water and landfill/pond leachate. Kentucky Power anticipates that wastewater treatment projects will be necessary at the Mitchell and Rockport Plants in response to this rulemaking. The expected date for a final ELG rule is September 30, 2015.
7. **Coal Combustion Residuals ("CCR") Rule –** EPA proposed the CCR Rule in June 2010 to address the disposal of coal combustion byproducts (coal ash, etc.). The proposed rule includes specific design and

monitoring standards for new and existing landfills and surface impoundments, as well as measures to ensure and maintain the structural integrity of surface impoundment/ponds. The proposed CCR rulemaking would require the conversion of most “wet” ash impoundments to “dry” ash landfills, the relining or closing of any remaining ash impoundment ponds, and the construction of additional waste water treatment facilities by approximately the first half of 2020. Kentucky Power anticipates that the CCR Rule—based on the preliminary assumption that these residual materials will be categorized as “Subtitle D,” or non-hazardous materials—would require plant modifications and capital expenditures to address these requirements by approximately 2019. At the time of this writing, the final rule is scheduled to be complete by December 19, 2014.

8. **Greenhouse Gas (“GHG”) Regulations** – EPA has been working on a regulatory program for greenhouse gas emissions from existing power plants since December 2010. On March 27, 2012, EPA proposed New Source Performance Standards (“NSPS”) for new fossil fuel power plants with a carbon dioxide (CO_2) emission limit of 1,000 lb/MWh, which is equivalent to the rate EPA assumes for a new natural gas combined cycle unit. More recently, on June 25, 2013, President Obama announced a climate action plan to address GHG emissions from all fossil-fired power plants which included a specific schedule for EPA to propose, finalize and implement greenhouse gas regulations. Under President Obama’s direction, the EPA issued a revised proposal for the GHG NSPS for new sources on January 8, 2014, and must finalize it in a “timely fashion.” EPA issued proposed GHG NSPS guidelines, referred to as the Clean Power Plan for existing sources on June 2, 2014 and plans to finalize these guidelines by June 1, 2015. States would develop and submit a plan to EPA for implementing the existing source guidelines by June 30, 2016, however a one year extension to this deadline is available for states submitting an individual plan, and a two year extension is available for states combining to submit a multi-state implementation plan.

Q. PLEASE DESCRIBE THE MAJOR PROVISIONS OF THE PROPOSED CLEAN POWER PLAN.

A. The proposed Clean Power Plan is built upon four "building blocks," which the EPA uses to calculate a proposed CO_2 emission rate target for each state. These four building blocks, and their basic assumptions in the proposed Clean Power Plan, are as follows:

1. Coal plant heat rate improvement - The EPA assumed that all coal generators can improve operating efficiency by 6%, resulting in lower CO_2 emission rates for those generating units;
2. Redispatch of natural gas generation – The EPA assumed that existing and new natural gas combined cycle (NGCC) generating units could increase their capacity factor to 70%, with the resulting increase in NGCC generation displacing more CO_2-intensive, coal and oil/gas steam generation;
3. Renewable Energy and Nuclear Energy – The EPA assumes that states will implement what in effect is a 13% national renewable portfolio standard by 2030, that no unplanned nuclear plant retirements occur, and that nuclear units currently under construction are completed;
4. End-use Energy Efficiency programs – The EPA assumes that states can eventually achieve annual incremental end-use energy efficiency levels equivalent to 1.5% of sales, up to approximately 10% cumulative energy savings by 2030.

Relying on various technical and economic assumptions for each of these building blocks, some generic and some state-specific, the EPA calculated what it believes to be an achievable CO_2 emission rate for each state, starting with 2012 fossil unit operations and emissions as a baseline. The proposed Kentucky target is 1,844 lbs of CO_2/MWh on an average basis from 2020 through 2029, and is reduced to 1,763 lbs of CO_2/MWh for 2030 and beyond. The yearly targets from 2020 – 2029 can be met as an average over that 10 year period. For Kentucky these targets result in proposed reductions of the state-wide CO_2 emission rate of 15% on average during 2020 – 2029, and 18% by 2030, based on 2012 operation and emissions. Similarly, the Indiana target is 1,607 lb. CO_2/MWh on an average basis from 2020 through 2029, and is reduced to 1,531 lb. CO_2/MWh for 2030 and beyond. These targets result in proposed reductions of the state-wide CO_2 emission rate in Indiana of 16% on average during 2020 through 2029, and 20% by 2030, based on 2012 operation and emissions. Lastly, the West Virginia target is 1,748 lb. CO_2/MWh on an average basis from 2020 through 2029, and is reduced to 1,620 lb. CO_2/MWh for 2030 and beyond. These targets result in proposed reductions of the state-wide CO_2 emission rate in West Virginia of 13% on average during 2020 through 2029, and 20% by 2030, based on 2012

Q. PLEASE GENERALLY DESCRIBE AEP'S INITIAL ASSESSMENT OF THE PROPOSED CLEAN POWER PLAN.

A. It is important to keep in mind that the emission rate targets proposed by the EPA vary widely by state. The proposed rule could result in significant costs to customers based on the overly aggressive goals proposed in each of the building blocks.

The timeline for regulatory development is very aggressive. State implementation plans likely won't be finalized and approved until 2018, and possibly beyond 2019. This tight timeframe limits the actions that can be taken to achieve the 2020 target.

The proposal provides little credit for the significant carbon dioxide emission reductions that have already been made by the electricity sector and that will continue to be made through the remainder of this decade with the retirement of coal-fired generation in response to environmental regulations and other factors. Across its eleven-state footprint, AEP's carbon dioxide emissions have been reduced by more than 21 percent since 2005, and will be even lower after AEP retires more than one-fourth of its existing coal-fueled power plant fleet by 2016 to comply with other EPA regulations such as MATS. The coal-fired plants that will remain, like the Mitchell and Rockport Plants, are the most efficient in the AEP fleet and are equipped with emission controls that were recently installed to meet other EPA requirements.

AEP views the targets included in each building block as aggressive, making overall compliance very difficult to achieve under the proposal as it currently exists.

VI. BIG SANDY PLANT ENVIRONMENTAL COMPLIANCE

Q. PLEASE DISCUSS THE CURRENT STATUS OF ENVIRONMENTAL CONTROLS AT BIG SANDY UNITS 1 AND 2.

A. Big Sandy Unit 2 currently operates with SCR and low NO_x burner ("LNB") systems for NO_x control, and an electrostatic precipitator ("ESP") for particulate matter control. Big Sandy Unit 1 currently operates with LNBs with over-fire air ("OFA") for NO_x control, and an ESP for particulate matter control. These controls allow the Big Sandy units to operate in compliance with existing requirements, including the CAIR NO_x program. Solid wastes, including fly ash and bottom ash, are handled through pond systems which allow for the treatment of ash sluice water and storage of the waste. The plant's wastewater is also treated through these pond systems in compliance with the plant's approved NPDES permit.

Q. FOR HOW LONG WILL KENTUCKY POWER CONTINUE CONSUMING COAL AT THE BIG SANDY PLANT?

A. Kentucky Power has announced that Big Sandy Unit 2 will retire the unit by June 1, 2015, and Big Sandy Unit 1 will be converted to burn natural gas during 2016. After the retirement of Unit 2, coal operations will continue for Unit 1 until the point at which that unit shuts down for the gas conversion outage. Beyond that date no coal will be consumed at the Big Sandy Plant. While the effective date for the MATS Rule is April 16, 2015, the MATS Rule allows for an extension of the Rule's effective date under certain circumstances. For Big Sandy Unit 2, an extension was granted from the Kentucky Department of Environmental Protection ("KDEP") to be consistent with the PJM capacity planning year. For Big Sandy Unit 1, an extension of one calendar year was granted by the KDEP to accommodate the schedule for the conversion to natural gas.

Q. WILL THERE BE ANY ENVIRONMENTAL REQUIREMENTS ASSOCIATED WITH THE RETIREMENT OF BIG SANDY UNIT 2 AND THE CONVERSION TO NATURAL GAS OF BIG SANDY UNIT 1?

A. Upon the retirement of Big Sandy Unit 2 and the conversion to natural gas at Big Sandy Unit 1, the closure of the fly ash pond will take place because it will no longer be needed. Currently that project is in the permitting stage. A closure design and application have been developed and submitted to the KYDEP for approval. Kentucky Power will be closing the ash pond consistent with the Kentucky solid waste requirements including dewatering the pond, regrading the ash to achieve appropriate drainage, installing a flexible membrane liner (FML) to prevent the infiltration of rainwater, placing 2 feet of soil cover to sustain vegetation and protect the FML, mitigating any impacted streams associated with borrow sites for the soil cover, and installing a groundwater monitoring system to ensure the adequate detection of any contamination. Construction associated with this project is slated to commence in 2016 and is expected to be a multi-year, phased project. The Company plans to file for a certificate of public convenience and necessity for the work in 2015.

VII. MITCHELL PLANT ENVIRONMENTAL COMPLIANCE

Q. PLEASE DISCUSS THE CURRENT STATUS OF ENVIRONMENTAL EMISSIONS CONTROLS AT THE MITCHELL PLANT.

A. Each Mitchell unit currently operates with an FGD system, an SCR system, LNBs, ESP, and trona injection to mitigate SO_3 emissions. Additionally, the majority of gypsum produced in the plant's FGD process is beneficially reused as a raw ingredient at the neighboring wallboard plant. Any excess or off-spec gypsum, along with the plant's fly ash and any bottom ash that cannot be beneficially reused, is disposed of in the Mitchell Plant's on-site landfill. Wastewater from the FGD system is treated in a treatment plant prior to discharge. Other plant wastewater discharges, such as cooling tower blowdown and bottom ash sluice water, are treated though the plant's pond system.

Q. DESCRIBE THE REGULATORY PROGRAMS THAT DROVE THE NEED FOR THE INITIAL INSTALLATION OF THESE CONTROLS AT MITCHELL PLANT.

A. The primary federal statute that drove the initial installation of electrostatic precipitators was the Clean Air Act, as implemented in the West Virginia SIP. Installation of LNBs and SCRs at Mitchell Plant was driven by the Clean Air Act Title IV and CAIR NO_X programs while the FGD system was installed to also comply with the Clean Air Act Title IV program and the CAIR SO_2 program.

Q. WILL THE EXISTING ENVIRONMENTAL CONTROLS AT THE MITCHELL PLANT MEET THE COMPLIANCE NEEDS OF THE MATS RULE?

A. Yes. The existing controls are expected to allow the plant to meet the requirements of the MATS Rule. A mercury monitoring system was installed and began service in December of 2014 to comply with the monitoring requirements of this rule.

Q. HAVE ANY MAJOR ENVIRONMENTAL PROJECTS ALREADY BEGUN AT THE MITCHELL PLANT TO MEET PROPOSED AND ANTICIPATED REGULATORY COMPLIANCE NEEDS?

A. Yes. As described in the Case No. 2012-00578 before this Commission, both Units 1 and 2 at the Mitchell Plant recently underwent a conversion to a dry fly ash handling system for the purpose of meeting more stringent limits in the facilities' NPDES permit. As necessitated by the dry fly ash conversion, a new landfill and haul road have been constructed to dispose of fly ash in dry form.

The appropriate disposal of solid waste is a requirement of West Virginia's solid waste regulations. It should be noted that these projects were planned and approved for funding prior to the transfer of Mitchell Plant to Kentucky Power. In addition to currently satisfying the plant's NPDES permit in meeting stringent wastewater discharge limits, these projects are also expected to help satisfy the anticipated requirements of the CCR Rule, although there may be a need to re-line the bottom ash pond for compliance with the final CCR Rule as well. Finally, additional waste water treatment technology may be needed at Mitchell Units 1 and 2 for compliance with the emerging ELG Rule.

Q. DOES THE COMPANY'S FOURTH AMENDED ENVIRONMENTAL COMPLIANCE PLAN ("2014 ENVIRONMETNAL COMPLIANCE PLAN") INCLUDE ANY NORMAL AND ON-GOING CAPITAL WORK NOT COVERED IN THE DESCRIPTIONS ABOVE?

A. Yes, the 2014 Environmental Compliance Plan includes periodic modifications and upgrades to Mitchell Plant's ESPs. This work is necessary to ensure this equipment can continuously meet the 10% opacity limit and particulate matter mass emissions limit contained in the Plant's Title V Air Permit. Similarly, the 2014 Environmental Compliance Plan also includes periodic modifications and upgrades to Mitchell Plant's ash (Bottom and Fly) handling systems. This work is necessary to ensure that these wastes are managed in conformance with West Virginia's solid waste regulations.

VIII. ROCKPORT PLANT ENVIRONMENTAL COMPLIANCE

Q. PLEASE DISCUSS THE CURRENT STATUS OF ENVIRONMENTAL CONTROLS AT THE ROCKPORT PLANT.

A. Both units at the Rockport Plant currently operate with LNBs and OFA for NO_x reduction, ESPs for particulate control, and activated carbon injection ("ACI") to achieve mercury reduction. The units consume a high percentage of low-sulfur coal from the Powder River Basin to minimize SO_2 emissions. In addition to these air emission controls, the plant operates a landfill for the disposal of fly ash and any bottom ash which is not beneficially reused. Wastewater is treated through the plant's pond system in accordance with the approved NPDES permit.

Q. DESCRIBE THE REGULATORY PROGRAMS THAT DROVE THE NEED FOR THE INITIAL INSTALLATION OF THESE CONTROLS AT THE ROCKPORT PLANT.

A. The primary federal statute that drove the initial installation of electrostatic precipitators was the Clean Air Act, as implemented in the Indiana SIP. Installation of LNBs and OFA at Rockport Plant was driven by the Clean Air Act Title IV and CAIR NO_X programs. Prior to its vactur, the Clean Air Mercury Rule ("CAMR") drove Rockport Plant's installation of the ACI system. Currently, the ACI system is undergoing minor upgrades and a switch to brominated activated carbon which is being driven by the mercury emission rate limit under the MATS Rule.

Q. WHAT PROJECTS ARE PLANNED AT THE ROCKPORT PLANT TO COMPLY WITH FUTURE REGULATIONS?

A. Currently both units at the Rockport Plant are in the process of being retrofitted with DSI systems. These systems will be operational prior to the April 16, 2015 effective date of the MATS Rule. In conjunction with the upgraded ACI system, the DSI systems will reduce acid gas emissions in a manner sufficient to comply with the Rule. The impact of the DSI systems on the Rockport Plant's fly ash waste stream requires an upgrade to the coal combustion waste landfill.

In addition to the DSI systems, I&M has requested permission from the Indiana Utility Regulatory Commission to retrofit Rockport Unit 1 with an SCR system by December 31, 2017.

Also, similar to the Mitchell Plant, I&M may be required to re-line the bottom ash pond for compliance with the final CCR Rule.

Q. ARE THE PROJECTS LISTED IN KENTUCKY POWER'S 2014 ENVIRONMENTAL COMPLIANCE PLAN REQUIRED TO COMPLY WITH THE ENVIRONMENTAL STATUTES AND REGULATIONS IDENTIFIED IN THIS PROCEEDING?

A. Yes. The projects listed are required to comply with the Federal Clean Air Act and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal.

VII. CONCLUSION

Q. PLEASE SUMMARIZE THE ENVIRONMENTAL REQUIREMENTS FOR THE BIG SANDY, MITCHELL, AND ROCKPORT PLANTS.

A. The environmental regulations facing Kentucky Power are stringent and will require reductions in the emissions of several air pollutants. The compliance requirements contained in the MATS Rule as well as the promise of potential future regulation of solid wastes and more stringent waste water standards will require the reduction of multiple emissions from Kentucky Power's generating plants. These emission reductions will be achieved through existing, planned, and anticipated environmental retrofits at the Mitchell and Rockport Plants, the retirement of Big Sandy Unit 2, and the refueling of Big Sandy Unit 1.

Q. WHY ARE THE PROJECTS LISTED IN KENTUCKY POWER COMPANY'S 2014 ENVIRONMENTAL COMPLIANCE PLAN NECESSARY FOR CONTINUED OPERATION OF KENTUCKY POWER'S GENERATING PLANTS?

A. The projects listed in the 2014 Environmental Compliance Plan allow Big Sandy, Mitchell, and Rockport Plants the ability to operate in compliance with the requirements of federal statutes which include the Clean Air Act, the Resource Conservation and Recovery Act, and the Clean Water Act. Without the implementation of these projects the Big Sandy, Mitchell, and Rockport Plants would not be able to legally operate. The placement in-service of these projects allows Kentucky Power to remain in compliance with environmental regulations so that these Plants can continue to provide Kentucky Power's customers with reliable generation.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp Civil Action No C2-99-1250 (Consolidated with C2-99-1182)
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE GREGORY L. FROST Magistrate Judge Norah McCann King Civil Action No C2-05-360

OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE GREGORY L. FROST Magistrate Judge Norah McCann King Civil Action No. C2-04-1098

<u>CONSENT DECREE</u>

TABLE OF CONTENTS

WHEREAS, the following complaints have been filed against American Electric Power Service Corporation, Indiana Michigan Power Company, Ohio Power Company, Appalachian Power Company, Cardinal Operating Company, and Columbus Southern Power Company in the above-captioned cases, *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-99-1182 and C2-99-1250 ("*AEP I*") and *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-04-1098 and C2-05-360 ("*AEP II*"):

(a) the United States of America ("United States"), on behalf of the United States Environmental Protection Agency ("EPA"), filed initial complaints on November 3, 1999 and April 8, 2005, and filed amended complaints on March 3, 2000 and September 17, 2004, pursuant to Sections 113(b), 165, and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413, 7475, and 7477;

(b) the States of New York, Connecticut, New Jersey, Vermont, New Hampshire, Maryland, and Rhode Island, and the Commonwealth of Massachusetts, after their motion to intervene was granted, filed initial complaints on December 14, 1999 and November 18, 2004, and filed amended complaints on April 5, 2000, September 24, 2002, and September 17, 2004, pursuant to Section 304 of the Act, 42 U.S.C. § 7604; and

(c) Ohio Citizen Action, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Valley Watch, Inc., Ohio Valley Environmental Coalition, West Virginia Environmental Council, Clean Air Council, Izaak Walton League of America, United States Public Interest Research Group, National Wildlife Federation, Indiana Wildlife Federation, League of Ohio Sportsmen, Sierra Club, and Natural Resources Defense Council, Inc. filed an initial complaint on November 19, 1999, and filed amended complaints on January 1, 2000 and September 16, 2004, pursuant to Section 304 of the Act, 42 U.S.C. § 7604;

WHEREAS, the complaints filed against Defendants in *AEP I* and *AEP II* sought injunctive relief and the assessment of civil penalties for alleged violations of, *inter alia*, the:

(a) Prevention of Significant Deterioration and Nonattainment New Source Review provisions in Part C and D of Subchapter I of the Act, 42 U.S.C. §§ 7470-7492, 7501-7515; and

(b) federally-enforceable state implementation plans developed by Indiana, Ohio, Virginia, and West Virginia;

WHEREAS, EPA issued notices of violation ("NOVs") to Defendants with respect to such allegations on November 2, 1999, November 22, 1999, and June 18, 2004;

WHEREAS, EPA provided Defendants and the States of Indiana, Ohio, and West Virginia, and the Commonwealth of Virginia, with actual notice pertaining to Defendants' alleged violations, in accordance with Section 113(a)(1) and (b) of the Act, 42 U.S.C. § 7413(a)(1) and (b);

WHEREAS, in their complaints, the United States, the States, and Citizen Plaintiffs (collectively, the "Plaintiffs") alleged, *inter alia,* that Defendants made major modifications to major emitting facilities, and failed to obtain the necessary permits and install the controls necessary under the Act to reduce sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and further alleged that such emissions damage human health and the environment;

WHEREAS, the Plaintiffs' complaints state claims upon which relief can be granted against Defendants under Sections 113, 165, and 167 of the Act, 42 U.S.C. §§ 7413, 7475, and 7477, and 28 U.S.C. § 1355;

WHEREAS, Defendants have denied and continue to deny the violations alleged in the complaints and NOVs, maintain that they have been and remain in compliance with the Act and are not liable for civil penalties or injunctive relief, and state that they are agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment;

WHEREAS, Defendants have installed and operated SCR technology on several Units in the AEP Eastern System, as those terms are defined herein, during the five (5) month ozone season to achieve emission reductions in compliance with the NO_x SIP Call;

WHEREAS, the Plaintiffs and Defendants anticipate that this Consent Decree, including the installation and operation of pollution control technology and other measures adopted pursuant to this Consent Decree, will achieve significant reductions of emissions from the AEP Eastern System and thereby significantly improve air quality;

WHEREAS, the liability phase of *AEP I* was tried on July 6-7, 2005, and July 11-12, 2005, and no decision has been rendered;

WHEREAS, the Parties have agreed, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Act; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

NOW, THEREFORE, without any admission by Defendants, and without adjudication of the violations alleged in the complaints or the NOVs, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, Sections 113, 167, and 304 of the Act, 42 U.S.C. §§ 7413, 7477, and 7604. Solely for the purposes of this Consent Decree, venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying complaints, and for no other purpose, Defendants waive all objections and defenses that they may have to the Court's jurisdiction over this action, to the Court's jurisdiction over Defendants, and to venue in this District. Defendants shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. Solely for the purposes of the complaints filed by the Plaintiffs in this matter and resolved by the Consent Decree, for the purposes of entry and enforcement of this Consent Decree, and for no other purpose, Defendants waive any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in or obligations of any party other than the Plaintiffs and Defendants. Except as provided in Section XXV (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice. To facilitate entry of this Consent Decree, upon the Date of Lodging of this Consent Decree the Parties shall file a Joint Motion to Consolidate *AEP I* and *AEP II* so that *AEP II* is consolidated into *AEP I*.

II. APPLICABILITY

2. Upon entry, the provisions of the Consent Decree shall apply to and be binding upon and inure to the benefit of Plaintiffs and Defendants, and their respective successors and assigns, and upon their officers, employees, and agents, solely in their capacities as such.

3. Defendants shall be responsible for providing a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, Defendants shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. For this reason, in any action to enforce this Consent Decree, Defendants shall not assert as a defense the failure of their officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless Defendants establish that such failure resulted from a Force Majeure Event, as defined in Paragraph 158 of this Consent Decree.

III. DEFINITIONS

Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree and, except as otherwise provided in this Consent Decree, every other term used in this Consent Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Consent Decree what such term means under the Act or those implementing regulations.

4. A "1-hour Average NO_x Emission Rate" for a re-powered gas-fired, electric generating unit means, and shall be expressed as, the average concentration in parts per million

("ppm") by dry volume, corrected to 15% O_2, as averaged over one (1) hour. In determining the 1-Hour Average NO_x Emission Rate, Defendants shall use CEMS in accordance with applicable reference methods specified in 40 C.F.R. Part 60 to calculate the emissions for each 15-minute interval within each clock hour, except as provided in this Paragraph. Compliance with the 1-Hour Average NO_x Emission Rate shall be shown by averaging all 15-minute CEMS interval readings within a clock hour, except that any 15-minute CEMS interval that contains any part of a startup or shutdown shall not be included in the calculation of that 1-Hour average. A minimum of two 15-minute CEMS interval readings within a clock hour, not including startup or shutdown intervals, is required to determine compliance with the 1-Hour average NO_x Emission Rate. All emissions recorded by CEMS shall be reported in 1-Hour averages.

5. A "30-Day Rolling Average Emission Rate" for a Unit means, and shall be expressed as, a lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the Unit during an Operating Day and the previous twenty-nine (29) Operating Days; second, sum the total heat input to the Unit in mmBTU during the Operating Day and the previous twenty-nine (29) Operating Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Operating Days by the total heat input during the thirty (30) Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown, and Malfunction within an Operating Day, except as follows:

a. Emissions and BTU inputs that occur during a period of Malfunction shall be excluded from the calculation of the 30-Day Rolling Average Emission

Rate if Defendants provide notice of the Malfunction to EPA in accordance with Paragraph 159 in Section XIV (Force Majeure) of this Consent Decree;

b. Emissions of NO_x and BTU inputs that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a given Unit during any 30-day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emission Rate and Defendants have installed, operated, and maintained the SCR in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NO_x emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) shall be the lesser of (i) those NO_x emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight (8) hours later, or (ii) those NO_x emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and

c. For SO_2, shall include all emissions and BTUs commencing from the time the Unit is synchronized with a utility electric distribution system through the time that the Unit ceases to combust fossil fuel and the fire is out in the boiler.

6. A "30-Day Rolling Average Removal Efficiency" means, for SO_2, at a Unit other than Conesville Unit 5 and Conesville Unit 6, the percent reduction in the mass of SO_2 achieved by a Unit's FGD system over a 30-Operating Day period and shall be calculated as follows: step one, sum the total pounds of SO_2 emitted as measured at the outlet of the FGD system for the Unit during the current Operating Day and the previous twenty-nine (29) Operating Days as measured at the outlet of the FGD system for that Unit; step two, sum the total pounds of SO_2 delivered to the inlet of the FGD system for the Unit during the current Operating Day and the previous twenty-nine (29) Operating Days as measured at the inlet to the FGD system for that Unit; step three, subtract the outlet SO_2 emissions calculated in step one from the inlet SO_2 emissions calculated in step two; step four, divide the remainder calculated in step three by the inlet SO_2 emissions calculated in step two; and step five, multiply the quotient calculated in step four by 100 to express as a percentage of removal efficiency. A new 30-day Rolling Average Removal Efficiency shall be calculated for each new Operating Day, and shall include all emissions that occur during all periods within each Operating Day except that emissions that occur during a period of Malfunction may be excluded from the calculation if Defendants provide Notice of the Malfunction to Plaintiffs in accordance with Section XIV (Force Majeure) and it is determined to be a Force Majeure Event pursuant to that Section.

7. "AEP Eastern System" means, solely for purposes of this Consent Decree, the following coal-fired, electric steam generating Units (with the nominal nameplate net capacity of each Unit):

a. Amos Unit 1 (800 MW), Amos Unit 2 (800 MW), and Amos Unit 3 (1300 MW) located in St. Albans, West Virginia;

b. Big Sandy Unit 1 (260 MW) and Big Sandy Unit 2 (800 MW) located in Louisa, Kentucky;

c. Cardinal Unit 1 (600 MW), Cardinal Unit 2 (600 MW), and Cardinal Unit 3 (630 MW) located in Brilliant, Ohio;

d. Clinch River Unit 1 (235 MW), Clinch River Unit 2 (235 MW), and Clinch River Unit 3 (235 MW) located in Carbo, Virginia;

e. Conesville Unit 1 (125 MW), Conesville Unit 2 (125 MW), Conesville Unit 3 (165 MW), Conesville Unit 4 (780 MW), Conesville Unit 5 (375 MW), and Conesville Unit 6 (375 MW) located in Conesville, Ohio;

f. Gavin Unit 1 (1300 MW) and Gavin Unit 2 (1300 MW) located in Cheshire, Ohio;

g. Glen Lyn Unit 5 (95 MW) and Glen Lyn Unit 6 (240 MW) located in Glen Lyn, Virginia;

h. Kammer Unit 1 (210 MW), Kammer Unit 2 (210 MW), and Kammer Unit 3 (210 MW) located in Moundsville, West Virginia;

i. Kanawha River Unit 1 (200 MW) and Kanawha River Unit 2 (200 MW) located in Glasgow, West Virginia;

j. Mitchell Unit 1 (800 MW) and Mitchell Unit 2 (800 MW) located in Moundsville, West Virginia;

k. Mountaineer Unit 1 (1300 MW) located in New Haven, West Virginia;

l. Muskingum River Unit 1 (205 MW), Muskingum River Unit 2 (205 MW), Muskingum River Unit 3 (215 MW), Muskingum River Unit 4 (215 MW), and Muskingum River Unit 5 (585 MW) located in Beverly, Ohio;

m. Picway Unit 9 (100 MW) located in Lockbourne, Ohio;

n. Rockport Unit 1 (1300 MW) and Rockport Unit 2 (1300 MW) located in Rockport, Indiana;

o. Sporn Unit 1 (150 MW), Sporn Unit 2 (150 MW), Sporn Unit 3 (150 MW), Sporn Unit 4 (150), and Sporn Unit 5 (450 MW) located in New Haven, West Virginia; and

p. Tanners Creek Unit 1 (145 MW), Tanners Creek Unit 2 (145 MW), Tanners Creek Unit 3 (205 MW), and Tanners Creek Unit 4 (500 MW) located in Lawrenceburg, Indiana.

8. "Boiler Island" means: a Unit's (a) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (b) combustion air system; (c) steam generating system (firebox, boiler tubes, and walls); and (d) draft system (excluding the stack), all as further described in "Interpretation of Reconstruction," by John B. Rasnic, U.S. EPA (November 25, 1986) and attachments thereto.

9. "CEMS" or "Continuous Emission Monitoring System" means, for obligations involving NO_x and SO_2 under this Consent Decree, the devices defined in 40 C.F.R. § 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

10. "Citizen Plaintiffs" means, collectively, Ohio Citizen Action, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Ohio Valley Environmental Coalition,

West Virginia Environmental Council, Clean Air Council, Izaak Walton League of America, United States Public Interest Research Group, National Wildlife Federation, Indiana Wildlife Federation, League of Ohio Sportsmen, Sierra Club, and Natural Resources Defense Council, Inc.

11. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§ 7401-7671q, and its implementing regulations.

12. "Clean Air Interstate Rule" or "CAIR" means the regulations promulgated by EPA on May 12, 2005, at 70 Fed. Reg. 25,161, which are entitled, "Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to NO_x SIP Call; Final Rule," and any subsequent amendments to that regulation, and any applicable, federally-approved state implementation plan or the federal implementation plan to implement CAIR.

13. "Consent Decree" or "Decree" means this Consent Decree and the appendices attached hereto, which are incorporated into this Consent Decree.

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, ESP, or Other NO_x Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

15. "Date of Entry" means the date this Consent Decree is approved or signed by the United States District Court Judge; provided, however, that if the Parties' Joint Motion to Consolidate, as specified in Paragraph 1, is denied or not decided, then the "Date of Entry"

means the date that the last of the two United States District Court Judges hearing these cases approves or signs this Consent Decree.

16. "Date of Lodging" means the date this Consent Decree is filed for lodging with the Clerk of the Court for the United States District Court for the Southern District of Ohio.

17. "Day" means, unless otherwise specified, calendar day.

18. "Defendants" or "AEP" means American Electric Power Service Corporation, Kentucky Power Company d/b/a American Electric Power, Indiana Michigan Power Company d/b/a American Electric Power, Ohio Power Company d/b/a American Electric Power, Cardinal Operating Company and its owners (Ohio Power and Buckeye Power, Inc.), Appalachian Power Company d/b/a American Electric Power, and Columbus Southern Power Company d/b/a American Electric Power.

19. "Eastern System-Wide Annual Tonnage Limitation" means the limitations, as specified in this Consent Decree, on the number of tons of the air pollutants that may be emitted from the AEP Eastern System during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of the air pollutants emitted during all periods of startup, shutdown, and Malfunction, except that emissions that occur during a period of Malfunction may be excluded from the calculation if Defendants provide Notice of the Malfunction to Plaintiffs in accordance with Section XIV (Force Majeure) and it is determined to be a Force Majeure Event pursuant to that Section.

20. "Emission Rate" means the number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU"), measured in accordance with this Consent Decree.

21. "EPA" means the United States Environmental Protection Agency.

22. "ESP" means electrostatic precipitator, a pollution control device for the reduction of PM.

23. "Environmental Mitigation Project" means a project funded or implemented by Defendants as a remedial measure to mitigate alleged damage to human health or the environment, including National Parks or Wilderness Areas, claimed to have been caused by the alleged violations described in the complaints or to compensate Plaintiffs for costs necessitated as a result of the alleged damages.

24. "Existing Unit" means a Unit that commenced operation prior to the Date of Lodging of this Consent Decree.

25. "Flue Gas Desulfurization System," or "FGD," means a pollution control device with one or more absorber vessels that employs flue gas desulfurization technology for the reduction of SO_2.

26. "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas.

27. An "Improved Unit" for NO_x means an AEP Eastern System Unit equipped with an SCR or scheduled under this Consent Decree to be equipped with an SCR, or required to be Retired, Retrofitted, or Re-powered. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for another. Any Other Unit in the AEP Eastern System can become an Improved Unit for NO_x if it is equipped with an SCR and the requirement to Continuously Operate such SCR is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and the Title V Permit applicable to that Unit.

28. An "Improved Unit" for SO_2 means an AEP Eastern System Unit equipped with an FGD or scheduled under this Consent Decree to be equipped with an FGD, or required to be Retired, Retrofitted, or Re-powered. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for another. Any Other Unit in the AEP Eastern System can become an Improved Unit for SO_2 if it is equipped with an FGD and the requirement to Continuously Operate such FGD is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and the Title V Permit applicable to that Unit.

29. "KW" means kilowatt or one thousand watts.

30. "lb/mmBTU" means one pound per million British thermal units.

31. "Malfunction" means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

32. "MW" means a megawatt or one million watts.

33. "NSR Permit" means a preconstruction permit issued by the permitting authority pursuant to Parts C or D of Subchapter I of the Clean Air Act.

34. "National Ambient Air Quality Standards" or "NAAQS" means national ambient air quality standards that are promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

35. "New and Newly Permitted Unit" means a Unit that commenced operation after the Date of Lodging of this Consent Decree, and that has been issued a final NSR Permit for SO_2 and NO_x that includes applicable Best Available Control Technology ("BACT") and/or Lowest

Achievable Emission Rate ("LAER") limitations, as those terms are respectively defined at 42 U.S.C. §§ 7479(3), 7501(3).

36. "Nonattainment NSR" means the nonattainment area New Source Review program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515, and its regulations, 40 C.F.R. Part 51.

37. "NO_x" means oxides of nitrogen, measured in accordance with the provisions of this Consent Decree.

38. "NO_x Allowance" means an authorization to emit a specified amount of NO_x that is allocated or issued under an emissions trading or marketable permit program of any kind that has been established under the Clean Air Act or a state implementation plan.

39. "NO_x CAIR Allocations" means the number of NO_x Allowances allocated to the AEP Eastern System Units pursuant to the Clean Air Interstate Rule, excluding any NO_x Allowances awarded by Indiana, Kentucky, Ohio, West Virginia, and Virginia to an AEP Eastern System Unit from the "compliance supplement pool," as that phrase is defined at 40 C.F.R. § 96.143, in a federally-approved state implementation plan, or federal implementation plan to implement CAIR.

40. "Operating Day" means any day on which a Unit fires Fossil Fuel.

41. "Other NO_x Pollution Controls" means the measures identified in the table in Paragraph 69 that will achieve reductions in NO_x emissions at the Units specified therein.

42. "Other SO_2 Measures" means the measures identified in Paragraph 90 that will achieve reductions in SO_2 emissions at the Units specified therein.

43. "Other Unit" means any Unit of the AEP Eastern System that is not an Improved Unit for the pollutant in question.

44. "Operational or Ownership Interest" means part or all of Defendants' legal or equitable operational or ownership interests in any Unit in the AEP Eastern System.

45. "Parties" means the United States, the States, the Citizen Plaintiffs, and Defendants. "Party" means one of the Parties.

46. "Plaintiffs" means the United States, the States, and the Citizen Plaintiffs.

47. "Plant-Wide Annual Rolling Tonnage Limitation for SO_2 at Clinch River" means the sum of the tons of SO_2 emitted during all periods of operation from the Clinch River plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, in the most recent month and the previous eleven (11) months. A new Annual Rolling Average Tonnage Limitation for years 2010 through 2014, and for 2015 and continuing thereafter, shall be calculated in accordance with Paragraph 88.

48. "Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer" means the sum of the tons of SO_2 emitted during all periods of operation from the Kammer plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, during the relevant calendar year (i.e., January 1 through December 31). A new Plant-Wide Annual Tonnage Limitation shall be calculated for each new calendar year.

49. "PM" means particulate matter, as measured in accordance with the provisions of this Consent Decree.

50. "PM CEMS" or "PM Continuous Emission Monitoring System" means the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic or paper record of PM emissions.

51. "PM Emission Rate" means the number of pounds of PM emitted per million BTU of heat input (lb/mmBTU), as measured in annual stack tests in accordance with EPA Method 5, 5B, or 17, 40 C.F.R. Part 60, including Appendix A.

52. "Project Dollars" means Defendants' expenditures and payments incurred or made in carrying out the Environmental Mitigation Projects identified in Section VIII (Environmental Mitigation Projects) of this Consent Decree to the extent that such expenditures or payments both: (a) comply with the requirements set forth in Section VIII (Environmental Mitigation Projects) and Appendix A of this Consent Decree, and (b) constitute Defendants' direct payments for such projects, or Defendants' external costs for contractors, vendors, and equipment.

53. "PSD" means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, and its regulations, 40 C.F.R. Part 52.

54. "Re-power" means either (1) the replacement of an existing pulverized coal boiler through the construction of a new circulating fluidized bed ("CFB") boiler or other technology of equivalent environmental performance that at a minimum achieves and maintains a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU or a 30-Day Rolling Average Removal Efficiency of at least ninety-five percent (95%) for SO_2 and a 30-Day Rolling Average Emission Rate not greater than 0.070 lb/mmBTU for NO_x; or (2) the modification of

such Unit, or removal and replacement of Unit components, such that the modified or replaced Unit generates electricity through the use of new combined cycle combustion turbine technology fueled by natural gas containing no more than 0.5 grains of sulfur per 100 standard cubic feet of natural gas, and at a minimum, achieves a 1-hour Average NO_x Emission Rate not greater than 2.0 ppm.

55. "Retire" means that Defendants shall: (a) permanently shut down and cease to operate the Unit; and (b) comply with any state and/or federal requirements applicable to that Unit. Defendants shall amend any applicable permits so as to reflect the permanent shutdown status of such Unit.

56. "Retrofit" means that the Unit must install and Continuously Operate both an SCR and an FGD. For the 600 MW listed in the table in Paragraph 68 and 87, "Retrofit" means that the Unit must meet a federally-enforceable 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for NO_x and a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for SO_2, measured in accordance with the requirements of this Consent Decree.

57. "Selective Catalytic Reduction System" or "SCR" means a pollution control device that employs selective catalytic reduction technology for the reduction of NO_x emissions.

58. "Selective Non-Catalytic Reduction" means a pollution control device for the reduction of NO_x emissions that utilizes ammonia or urea injection into the boiler.

59. "SO_2" means sulfur dioxide, as measured in accordance with the provisions of this Consent Decree.

60. "SO_2 Allowance" means "allowance" as defined at 42 U.S.C. § 7651a(3): "an authorization, allocated to an affected unit by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide."

61. "SO_2 Allocations" means the number of SO_2 Allowances allocated to the AEP Eastern System Units.

62. "Super-Compliant NO_x Allowance" means an allowance attributable to reductions beyond the requirements of this Consent Decree as determined in accordance with Paragraph 80.

63. "Super-Compliant SO_2 Allowance" means an allowance attributable to reductions beyond the requirements of this Consent Decree as determined in accordance with Paragraph 98.

64. "States" means the States of Connecticut, Maryland, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, and the Commonwealth of Massachusetts.

65. "Title V Permit" means the permit required for Defendants' major sources under Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e.

66. "Unit" means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine, and boiler, and all ancillary equipment, including pollution control equipment. An electric steam generating station may comprise one or more Units.

IV. NO_x EMISSION REDUCTIONS AND CONTROLS

A. Eastern System-Wide Annual Tonnage Limitations for NO_x.

67. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP

Eastern System, collectively, shall not emit NO_x in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for NO_x**
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016, and each year thereafter	72,000 tons

B. NO_x Emission Limitations and Control Requirements.

68. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate SCR on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-power such Unit:

Unit	**NO_x Pollution Control**	**Date**
Amos Unit 1	SCR	January 1, 2008
Amos Unit 2	SCR	January 1, 2009
Amos Unit 3	SCR	January 1, 2008
Big Sandy Unit 2	SCR	January 1, 2009
Cardinal Unit 1	SCR	January 1, 2009
Cardinal Unit 2	SCR	January 1, 2009

Unit	NO_x Pollution Control	Date
Cardinal Unit 3	SCR	January 1, 2009
Conesville Unit 1	Retire, Retrofit, or Re-power	Date of Entry of this Consent Decree
Conesville Unit 2	Retire, Retrofit, or Re-power	Date of Entry of this Consent Decree
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	SCR	December 31, 2010
Gavin Unit 1	SCR	January 1, 2009
Gavin Unit 2	SCR	January 1, 2009
Mitchell Unit 1	SCR	January 1, 2009
Mitchell Unit 2	SCR	January 1, 2009
Mountaineer Unit 1	SCR	January 1, 2008
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	SCR	January 1, 2008
Rockport Unit 1	SCR	December 31, 2017
Rockport Unit 2	SCR	December 31, 2019
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3, Tanners Creek Units 1-3, and/or Kammer Units 1-3	Retire, Retrofit, or Re-power	December 31, 2018

69. Other NO_x Pollution Controls. No later than the dates set forth in the table below, Defendants shall Continuously Operate the Other NO_x Pollution Controls on the Units identified therein:

Unit	**Other NO_x Pollution Controls**	**Date**
Big Sandy Unit 1	Low NO_x Burners	Date of Entry
Glen Lyn Units 5 and 6	Low NO_x Burners	Date of Entry
Clinch River Units 1, 2, and 3	Low NO_x Burners, and Selective Non-catalytic Reduction	For Low NO_x Burners, Date of Entry, and, for Selective Non-Catalytic Reduction, December 31, 2009
Conesville Units 5 and 6	Low NO_x Burners	Date of Entry
Kammer Units 1, 2, and 3	Overfire Air	Date of Entry
Kanawha River Units 1 and 2	Low NO_x Burners	Date of Entry
Picway Unit 9	Low NO_x Burners	Date of Entry
Tanners Creek Units 1, 2, and 3	Low NO_x Burners	Date of Entry
Tanners Creek Unit 4	Overfire Air	Date of Entry

C. General Provisions for Use and Surrender of NO_x Allowances.

70. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use NO_x Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation or Eastern System-Wide Annual Tonnage Limitation required by this Decree, by using, tendering,

or otherwise applying NO_x Allowances to achieve compliance or offset any emissions above the limits specified in this Consent Decree.

71. As required by this Section IV of this Consent Decree, Defendants shall surrender NO_x Allowances that would otherwise be available for sale, trade, or transfer as a result of actions taken by Defendants to comply with the requirements of this Consent Decree.

72. NO_x Allowances allocated to the AEP Eastern System may be used by Defendants to meet their own federal and/or state Clean Air Act regulatory requirements for the Units included in the AEP Eastern System. Subject to Paragraph 70, nothing in this Consent Decree shall prevent Defendants from purchasing or otherwise obtaining NO_x Allowances from another source for purposes of complying with their own federal and/or state Clean Air Act requirements to the extent otherwise allowed by law.

73. The requirements in this Consent Decree pertaining to Defendants' use and surrender of NO_x Allowances are permanent injunctions not subject to any termination provision of this Consent Decree. These provisions shall survive any termination of this Consent Decree.

D. Use of Excess NO_x Allowances.

74. Calculation of Unrestricted and Restricted NO_x Allowances. On an annual basis, beginning in 2009, Defendants shall calculate the difference between the NO_x CAIR Allocations for the Units in the AEP Eastern System for that year and the annual Eastern System-Wide Tonnage Limitations for NO_x for that calendar year. This difference represents the total Excess NO_x Allowances for that calendar year. For purposes of this Consent Decree, for each year commencing in 2009 and ending in 2015, forty-two percent (42%) of the Excess NO_x Allowances shall be Unrestricted Excess NO_x Allowances and fifty-eight percent (58%) shall be

Restricted Excess NO_x Allowances. Commencing in 2016, and continuing thereafter, all Excess NO_x Allowances shall be Restricted Excess NO_x Allowances.

75. Use and Surrender of Unrestricted Excess NO_x Allowances. For each calendar year commencing in 2009 and ending in 2015, Defendants may use Unrestricted Excess NO_x Allowances in any manner authorized by law. No later than March 1, 2016, Defendants must surrender, or transfer to a non-profit third party selected by Defendants for surrender, all unused Unrestricted Excess NO_x Allowances subject to surrender accumulated during the period from 2009 through 2015.

76. Use and Surrender of Restricted Excess NO_x Allowances. Beginning in calendar year 2009, and for each calendar year thereafter, Defendants shall calculate the difference between the number of any Restricted Excess NO_x Allowances and the number of NO_x Allowances that is equal to the amount of actual NO_x emissions from: (a) any New and Newly Permitted Unit as defined in this Consent Decree, and (b) the following five natural-gas plants but only up to a cumulative total of 1200 tons of NO_x in any single year: Ceredo Generating Station located near Ceredo, West Virginia, with a nominal generating capacity of 505 megawatts; Waterford Energy Center located in southeastern Ohio, with a nominal generating capacity of 821 megawatts; Darby Electric Generating Station located near Columbus, Ohio, with a nominal generating capacity of 480 megawatts; Lawrenceburg Generating Station located in Lawrenceburg, Indiana, with a generating capacity of 1,096 megawatts; and a natural gas-fired power plant under construction near Dresden, Ohio, with a nominal generating capacity of 580 megawatts. This difference shall be the amount of Restricted Excess NO_x Allowances

potentially subject to surrender in 2016. During calendar years 2009 through 2015, Defendants may accumulate Restricted Excess NO_x Allowances potentially subject to surrender in 2016.

77. NO_x Allowances from Renewable Energy. Beginning in calendar year 2009, and for each calendar year thereafter, Defendants may subtract from the number of Restricted Excess NO_x Allowances potentially subject to surrender, a number of allowances calculated in accordance with this Paragraph. To calculate such number, Defendants shall use the following method: multiply 0.0002 by the sum of (a) the actual annual generation in MWH/year generated from solar or wind power projects first owned or operated by Defendants after the Date of Lodging of this Consent Decree, and (b) the actual annual generation in MWH/year purchased by Defendants from solar or wind power projects in any year after the Date of Lodging of this Consent Decree. Such figure so calculated shall be subtracted from the number of Restricted Excess NO_x Allowances potentially subject to surrender each year. The remainder shall be the Restricted Excess NO_x Allowances subject to surrender.

78. Defendants may, solely at their discretion, use Restricted Excess NO_x Allowances at a New and Newly Permitted Unit for which Defendants have received a final NSR Permit from the permitting agency even if the NSR Permit has been appealed but not stayed during the permit appeal process. If Defendants use Restricted Excess NO_x Allowances at such New and Newly Permitted Unit, and the emissions from such New and Newly Permitted Unit are greater than what such Unit is permitted to emit after final adjudication of the appeal process, Defendants shall, within thirty (30) days of such final adjudication, retire an amount of NO_x Allowances equal to the number of tons of NO_x actually emitted that exceeded the finally adjudicated permit limit.

79. No later than March 1, 2016, the total number of Restricted Excess NO_x Allowances subject to surrender accumulated during 2009 through 2015 as calculated in accordance with Paragraphs 74, 76, and 77, shall be surrendered or transferred to a non-profit third party selected by Defendants for surrender, pursuant to Subsection F, below. Beginning in calendar year 2016, and for each calendar year thereafter, the total number of Restricted Excess NO_x Allowances subject to surrender for that year calculated in accordance with Paragraph 74, 76 and 77, shall be surrendered, or transferred to a non-profit third party selected by Defendants for surrender, by March 1 of the following calendar year.

E. Super-Compliant NO_x Allowances.

80. In each calendar year beginning in 2009, and continuing thereafter, Defendants may use in any manner authorized by law any NO_x Allowances made available in that year as a result of maintaining actual NO_x emissions from the AEP Eastern System below the Eastern System-Wide Annual Tonnage Limitations for NO_x under this Consent Decree for each calendar year. Defendants shall timely report the generation of such Super-Compliant NO_x Allowances in accordance with Section XI (Periodic Reporting) and Appendix B of this Consent Decree.

F. Method for Surrender of Excess NO_x Allowances.

81. For purposes of this Consent Decree, the "surrender" of Excess Restricted or Unrestricted Excess NO_x Allowances subject to surrender means permanently surrendering to EPA NO_x Allowances from the accounts administered by EPA so that such NO_x Allowances can never be used thereafter to meet any compliance requirement under the Clean Air Act, a state implementation plan, or this Consent Decree.

82. For all Restricted or Unrestricted Excess NO_x Allowances subject to surrender required to be surrendered to EPA in Paragraphs 79 and 75, above, Defendants or the third party recipient(s) (as the case may be) shall first submit a NO_x Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such NO_x Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, Defendants or the third party recipient(s) shall irrevocably authorize the transfer of these NO_x Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the NO_x Allowances being surrendered.

83. If any NO_x Allowances required to be surrendered under this Consent Decree are transferred directly to a non-profit third party, Defendants shall include a description of such transfer in the next report submitted to EPA as required by Section XI (Periodic Reporting) of this Consent Decree. Such report shall: (a) identify the non-profit third party recipient(s) of the NO_x Allowances and list the serial numbers of the transferred NO_x Allowances; and (b) include a certification by the third party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NO_x Allowances and will not use any of the NO_x Allowances to meet any obligation imposed by any environmental law. No later than the second periodic report due after the transfer of any NO_x Allowances, Defendants shall include a statement that the third party recipient(s) surrendered the NO_x Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 82 within one (1) year after Defendants transferred the NO_x Allowances to them. Defendants shall not have complied with the NO_x Allowance

surrender requirements of this Paragraph until all third party recipient(s) have actually surrendered the transferred NO_x Allowances to EPA.

G. Reporting Requirements for NO_x Allowances.

84. Defendants shall comply with the reporting requirements for NO_x Allowances as described in Section XI (Periodic Reporting) and Appendix B.

H. General NO_x Provisions.

85. To the extent a NO_x Emission Rate is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine such Emission Rate.

V. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. Eastern System-Wide Annual Tonnage Limitations for SO_2.

86. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for SO_2**
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons

Calendar Year	Eastern System-Wide Annual Tonnage Limitations for SO_2
2015	275,000 tons
2016	260,000 tons
2017	235,000 tons
2018	184,000 tons
2019, and each year thereafter	174,000 tons

B. SO_2 Emission Limitations and Control Requirements.

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-power such Unit:

Unit	SO_2 Pollution Control	Date
Amos Units 1 and 3	FGD	December 31, 2009
Amos Unit 2	FGD	December 31, 2010
Big Sandy Unit 2	FGD	December 31, 2015
Cardinal Units 1 and 2	FGD	December 31, 2008
Cardinal Unit 3	FGD	December 31, 2012
Conesville Units 1 and 2	Retire, Retrofit, or Re-power	Date of Entry
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	FGD	December 31, 2010
Conesville Unit 5	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009

Unit	SO_2 Pollution Control	Date
Conesville Unit 6	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Gavin Units 1 and 2	FGD	Date of Entry
Mitchell Units 1 and 2	FGD	December 31, 2007
Mountaineer Unit 1	FGD	December 31, 2007
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	FGD	December 31, 2015
Rockport Unit 1	FGD	December 31, 2017
Rockport Unit 2	FGD	December 31, 2019
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3, Tanners Creek Units 1-3, and/or Kammer Units 1-3	Retire, Retrofit, or Re-power	December 31, 2018

88. Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River. Beginning on January 1, 2010, and continuing through December 31, 2014, Defendants shall limit their total annual SO_2 emissions at the Clinch River plant to a Plant-Wide Annual Rolling Average Tonnage Limitation of 21,700 tons. Beginning on January 1, 2015, and continuing thereafter, Defendants shall limit their total annual SO_2 emissions at the Clinch River plant to a Plant-Wide Annual Rolling Average Tonnage Limitation of 16,300 tons. For purposes of calculating the Plant-Wide Annual Rolling Average Tonnage Limitation that begins in 2010, Defendants shall use the period beginning January 1, 2010 through December 31, 2010 to

establish the initial annual period that is subject to the Plant-Wide Annual Rolling Average Tonnage Limitation for 2010 through 2014. Defendants shall then calculate a new Plant-Wide Annual Rolling Average Tonnage Limitation each month thereafter through December 31, 2014, by averaging the most recent month with the previous eleven (11) months. For purposes of calculating the Plant-Wide Annual Rolling Average Tonnage Limitation that begins in 2015, Defendants shall use the period beginning January 1, 2015 through December 31, 2015 to establish the initial annual period that is subject to the Plant-Wide Annual Average Rolling Tonnage Limitation for 2015. Defendants shall then calculate a new Plant-Wide Annual Rolling Average Tonnage Limitation each month thereafter by averaging the most recent month with the previous eleven (11) months.

89. Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer. Beginning on January 1, 2010, and continuing annually thereafter, Defendants shall limit their total annual SO_2 emissions at the Kammer plant to a Plant-Wide Annual Tonnage Limitation of 35,000 tons.

90. Other SO_2 Measures. No later than the dates set forth in the table below, Defendants shall comply with the limit on coal sulfur content for such Units, at all times that the Units are in operation:

Unit	Other SO_2 Measures	Date
Big Sandy Unit 1	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis	Date of Entry
Glen Lyn Units 5 and 6	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis.	Date of Entry

Unit	Other SO_2 Measures	Date
Kanawha River Units 1 and 2	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis	Date of Entry
Tanners Creek Units 1, 2, and 3	Units can only burn coal with a sulfur content no greater than 1.2 lb/mmBTU on an annual average basis	Date of Entry
Tanners Creek Unit 4	Unit can only burn coal with a sulfur content no greater than 1.2 % on an annual average basis	Date of Entry

C. Use and Surrender of SO_2 Allowances.

91. Defendants may use SO_2 Allowances allocated to the AEP Eastern System by the Administrator of EPA under the Act, or by any state under its state implementation plan, to meet their own federal and/or state regulatory requirements for the Units included in the AEP Eastern System. Subject to Paragraph 92, nothing in this Consent Decree shall prevent Defendants from purchasing or otherwise obtaining SO_2 Allowances from another source for purposes of complying with their own federal and/or state Clean Air Act requirements to the extent otherwise allowed by law.

92. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use any SO_2 Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation, Eastern System-Wide Annual Tonnage Limitations, Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, or Plant-Wide Annual Tonnage Limitation

for SO_2 at Kammer required by this Consent Decree by using, tendering, or otherwise applying SO_2 Allowances to achieve compliance or offset any emissions above the limits specified in this Consent Decree.

93. On an annual basis beginning in 2010, and continuing thereafter, Defendants shall calculate the number of Excess SO_2 Allowances by subtracting the number of SO_2 Allowances equal to the annual Eastern System-Wide Tonnage Limitations for SO_2 for each calendar year times the applicable allowance surrender ratio from the annual SO_2 Allocations for all Units within the AEP Eastern System for the same calendar year. Defendants shall surrender, or transfer to a non-profit third party selected by Defendants for surrender, all Excess SO_2 Allowances that have been allocated to the AEP Eastern System for the specified calendar year by the Administrator of EPA under the Act or by any state under its state implementation plan. Defendants shall make the surrender of SO_2 Allowances required by this Paragraph to EPA by March 1 of the immediately following calendar year.

D. Method for Surrender of Excess SO_2 Allowances.

94. For purposes of this Subsection, the "surrender" of Excess SO_2 Allowances means permanently surrendering allowances from the accounts administered by EPA so that such allowances can never be used thereafter to meet any compliance requirement under the Clean Air Act, a state implementation plan, or this Consent Decree.

95. If any SO_2 Allowances required to be surrendered under this Consent Decree are transferred directly to a non-profit third party, Defendants shall include a description of such transfer in the next report submitted to EPA pursuant to Section XI (Periodic Reporting) of this Consent Decree. Such report shall: (i) identify the non-profit third party recipient(s) of the SO_2

Allowances and list the serial numbers of the transferred SO_2 Allowances; and (ii) include a certification by the third party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the second periodic report due after the transfer of any SO_2 Allowances, Defendants shall include a statement that the third party recipient(s) surrendered the SO_2 Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 96 within one (1) year after Defendants transferred the SO_2 Allowances to them. Defendants shall not have complied with the SO_2 Allowance surrender requirements of this Paragraph until all third party recipient(s) have actually surrendered the transferred SO_2 Allowances to EPA.

96. For all SO_2 Allowances surrendered to EPA, Defendants or the third party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, Defendants or the third party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO_2 Allowances being surrendered.

97. The requirements in this Consent Decree pertaining to Defendants' surrender of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree. These provisions shall survive any termination of this Consent Decree in whole or in part.

E. Super-Compliant SO_2 Allowances.

98. In each calendar year beginning in 2010, and continuing thereafter, Defendants may use in any manner authorized by law any SO_2 Allowances made available in that year as a result of maintaining actual SO_2 emissions from the AEP Eastern System below the Eastern System-Wide Annual Tonnage Limitations for SO_2 under this Consent Decree for each calendar year. Defendants shall timely report the generation of such Super-Compliant SO_2 Allowances in accordance with Section XI (Periodic Reporting) and Appendix B of this Consent Decree.

F. Reporting Requirements for SO_2 Allowances.

99. Defendants shall comply with the reporting requirements for SO_2 Allowances as described in Section XI (Periodic Reporting) and Appendix B.

G. General SO_2 Provisions.

100. To the extent an Emission Rate or 30-Day Rolling Average Removal Efficiency for SO_2 is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine such Emission Rate or Removal Efficiency.

101. Notwithstanding Paragraphs 6 and 100, the 30-Day Rolling Average Removal Efficiency for SO_2 at Conesville Unit 5 and Conesville Unit 6 shall be determined in accordance with Appendix C.

VI. PM EMISSION REDUCTIONS AND CONTROLS

A. Optimization of Existing ESPs.

102. Beginning thirty (30) days after the Date of Entry, and continuing thereafter, Defendants shall Continuously Operate each ESP on Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5 to maximize PM emission reductions at all times when the Unit is in

operation, provided that such operation of the ESP is consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the ESP. Defendants shall, at a minimum, to the extent reasonably practicable: (a) fully energize each section of the ESP for each unit, and repair any failed ESP section at the next planned Unit outage (or unplanned outage of sufficient length); (b) operate automatic control systems on each ESP to maximize PM collection efficiency; (c) maintain power levels delivered to the ESPs, consistent with manufacturers' specifications, the operational design of the Unit, and good engineering practices; and (d) inspect for and repair during the next planned Unit outage (or unplanned outage of sufficient length) any openings in ESP casings, ductwork, and expansion joints to minimize air leakage.

B. PM Emission Rate and Testing.

103. No later than the dates specified in the table below, Defendants shall Continuously Operate each Unit specified therein to achieve and maintain a PM Emission Rate no greater than 0.030 lb/mmBTU:

Unit	**Date to Achieve and Maintain PM Emission Rate**
Cardinal Unit 1	December 31, 2009
Cardinal Unit 2	December 31, 2009
Muskingum River Unit 5	December 31, 2012

104. On or before the date established by this Consent Decree for Defendants to achieve and maintain 0.030 lb/mmBTU at Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5, Defendants shall conduct a performance test for PM that demonstrates compliance with the PM Emission Rate required by this Consent Decree. Within forty-five (45) days of each such performance test, Defendants shall submit the results of the performance test to Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree.

C. PM Emissions Monitoring.

105. Beginning in calendar year 2010 for Cardinal Unit 1 and Cardinal Unit 2, and calendar year 2013 for Muskingum River Unit 5, and continuing in each calendar year thereafter, Defendants shall conduct a stack test for PM on each stack servicing Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. The annual stack test requirement imposed by this Paragraph may be satisfied by stack tests conducted by Defendants as required by their permits from the State of Ohio for any year that such stack tests are required under the permits.

106. The reference methods and procedures for determining compliance with PM Emission Rates shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, 5B, or 17, or an alternative method that is promulgated by EPA, requested for use herein by Defendants, and approved for use herein by EPA. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. § 60.48Da(b) and (e), or any federally-approved method contained in the Ohio State Implementation Plan. Defendants shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f). The results of each PM stack test shall be submitted to EPA within forty-five (45) days of completion of each test.

D. Installation and Operation of PM CEMS.

107. Defendants shall install, calibrate, operate, and maintain PM CEMS, as specified below. Each PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units of lb/mmBTU. Defendants shall maintain, in an electronic database, the hourly average emission values produced by all PM CEMS in lb/mmBTU. Defendants shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating.

108. No later than December 31, 2011, Defendants shall submit to EPA pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree: (a) a plan for the installation and certification of each PM CEMS, and (b) a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, Defendants shall use the criteria set forth in 40 C.F.R. Part 60, Appendix B, Performance Specification 11, and Appendix F, Procedure 3. Following approval by EPA of the protocol, Defendants shall thereafter operate each PM CEMS in accordance with the approved protocol.

109. No later than the dates specified below, Defendants shall install, certify, and operate PM CEMS on the stacks or common stacks for Cardinal Unit 1, Cardinal Unit 2, and a third Unit, as further described in Paragraph 110:

Stack	Date to Commence Operation of PM CEMS
Cardinal Unit 1	December 31, 2012
Cardinal Unit 2	December 31, 2012
Unit to be identified pursuant to Paragraph 110	December 31, 2012

110. No later than December 31, 2011, Defendants shall identify, subject to Plaintiffs' approval, the third Unit required by Paragraph 109.

111. No later than ninety (90) days after Defendants begin operation of the PM CEMS, Defendants shall conduct tests of each PM CEMS to demonstrate compliance with the PM CEMS installation and certification plan submitted to and approved by EPA.

112. Demonstration that PM CEMS are Infeasible. Defendants shall operate the PM CEMS for at least two (2) years on each of the Units specified in Paragraphs 109 and 110. After two (2) years of operation, Defendants may attempt to demonstrate that it is infeasible to continue operating PM CEMS. As part of such demonstration, Defendants shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall explain the basis for stopping operation of the PM CEMS and propose an alternative PM monitoring plan. If the United States disapproves the alternative PM monitoring plan, or if the United States rejects Defendants' claim that it is infeasible to continue operating PM CEMS, such disagreement is subject to Section XV (Dispute Resolution).

113. "Infeasible to Continue Operating PM CEMS" Standard. Operation of a PM CEMS shall be considered no longer feasible if: (a) the PM CEMS cannot be kept in proper

condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol, or (b) Defendants demonstrate that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If EPA determines that Defendants have demonstrated pursuant to this Paragraph that operation is no longer feasible, Defendants shall be entitled to discontinue operation of and remove the PM CEMS.

114. PM CEMS Operations Will Continue During Dispute Resolution or Proposals for Alternative Monitoring. Until EPA approves an alternative monitoring plan, or until the conclusion of any proceeding under Section XV (Dispute Resolution), Defendants shall continue to operate the PM CEMS. If EPA has not issued a decision regarding an alternative monitoring plan within 120 days, Defendants may initiate action under Section XV (Dispute Resolution).

E. PM Reporting.

115. Defendants shall comply with the reporting requirements for PM as described in Section XI (Periodic Reporting) and Appendix B.

F. General PM Provisions.

116. Although stack testing shall be used to determine compliance with the PM Emission Rate established by this Consent Decree, data from the PM CEMS shall be used, at a minimum, to monitor progress in reducing PM emissions.

VII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

117. Emission reductions that result from actions required to be taken by Defendants after the Date of Entry of this Consent Decree to comply with the requirements of this Consent Decree shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit or offset under the Clean Air Act's Nonattainment NSR and PSD programs.

118. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by a State or EPA as creditable contemporaneous emission decreases for the purpose of attainment demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS, PSD increment, or air quality related values, including visibility, in a Class I area.

VIII. ENVIRONMENTAL MITIGATION PROJECTS

119. Defendants shall implement the Environmental Mitigation Projects ("Projects") described in Appendix A to this Consent Decree and fund the categories of Projects described in Subsection B, below, in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree. In funding and/or implementing all such Projects in Appendix A and Subsection B, Defendants shall expend moneys and/or implement Projects valued at no less than $36 million for the Projects identified in Appendix A and $24 million for the payments to the States to fund Projects within the categories set forth in Subsection B. Defendants shall fund and/or implement such Projects over a period of no later than five (5) years from the Date of Entry. Defendants may propose establishing one or more qualified settlement funds within the meaning of Treas. Reg. §1.468B-1 in conjunction with one or more

Mitigation Projects. Any such trust would be established pursuant to a trust agreement in a form to be mutually agreed upon by the affected Parties. Nothing in the foregoing is intended by the United States to be a determination or opinion regarding whether such trust would meet the requirements of Treas. Reg. §1.468B-1 or is otherwise appropriate.

A. Requirements for Projects Described in Appendix A ($36 million).

120. Defendants shall maintain, and present to EPA upon request, all documents to substantiate the Project Dollars expended to implement the Projects described in Appendix A, and shall provide these documents to EPA within thirty (30) days of a request for the documents.

121. All plans and reports prepared by Defendants pursuant to the requirements of this Section of the Consent Decree and required to be submitted to EPA shall be publicly available from Defendants without charge.

122. Defendants shall certify, as part of each plan submitted to EPA for any Project, that Defendants are not otherwise required by law to perform the Project described in the plan, that Defendants are unaware of any other person who is required by law to perform the Project, and that Defendants will not use any Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law, including any applicable renewable portfolio standards.

123. Defendants shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

124. If Defendants elect (where such an election is allowed) to undertake a Project by contributing funds to another person or entity that will carry out the Project in lieu of Defendants, but not including Defendants' agents or contractors, that person or instrumentality

must, in writing: (a) identify its legal authority for accepting such funding; and (b) identify its legal authority to conduct the Project for which Defendants contribute the funds. Regardless of whether Defendants elect (where such election is allowed) to undertake a Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, Defendants acknowledge that they will receive credit for the expenditure of such funds as Project Dollars only if Defendants demonstrate that the funds have been actually spent by either Defendants or by the person or instrumentality receiving them, and that such expenditures met all requirements of this Consent Decree.

125. Defendants shall comply with the reporting requirements for Appendix A Projects as described in Section XI (Periodic Reporting) and Appendix B.

126. Within sixty (60) days following the completion of each Project required under this Consent Decree (including any applicable periods of demonstration or testing), Defendants shall submit to the United States a report that documents the date that the Project was completed, Defendants' results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Defendants in implementing the Project.

B. Mitigation Projects to be Conducted by the States ($24 million).

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as

designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified in writing by the States. Notwithstanding the $4.8 million and 5-year limitation above, if the total costs of the projects submitted in any one or more years are less than $4.8 million, the difference between that amount and $4.8 million will be available for funding by Defendants of new or previously submitted projects in the following years, except that all amounts not designated by the States within ten (10) years after the Date of Entry of this Consent Decree shall expire.

128. Categories of Projects. The States agree to use money funded by Defendants to implement Projects that pertain to energy efficiency and/or pollution reduction. Such projects may include, but are not limited by, the following:

a. Retrofitting land and marine vehicles (e.g., automobiles, off-road and on-road construction and other vehicles, trains, ferries) and transportation terminals and ports, with pollution control devices, such as particulate matter traps, computer chip reflashing, and battery hybrid technology;

b. Truck-stop and marine port electrification;

c. Purchase and installation of photo-voltaic cells on buildings;

d. Projects to conserve energy use in new and existing buildings, including appliance efficiency improvement projects, weatherization projects, and projects intended to meet EPA's Green Building guidelines (see http://www.epa.gov/greenbuilding/pubs/enviro-issues.htm) and/or the Leadership in Energy and Environmental Design (LEED) Green Building Rating System (see http://www.usgbc.org/DisplayPage.aspx?CategoryID=19), and projects to collect information in rental markets to assist in design of efficiency and conservation programs;

e. Construction associated with the production of energy from wind, solar, and biomass;

f. "Buy back" programs for dirty old motors (e.g., automobile, lawnmowers, landscape equipment);

g. Programs to remove and/or replace oil-fired home heating equipment to allow use of ultra-low sulfur oil, and outdoor wood-fired boilers;

h. Purchase and retirement of SO_2 and NO_x allowances; and

i. Funding program to improve modeling of mobile source sector.

IX. CIVIL PENALTY

129. Within thirty (30) days after the Date of Entry, Defendants shall pay to the United States a civil penalty in the amount of $15,000,000. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 1999v01542 and DOJ Case Number 90-5-2-1-06893 and the civil action case name and consolidated case numbers of this action. The costs of such EFT shall be Defendants' responsibility. Payment shall be made in accordance with instructions provided to Defendants by the Financial Litigation Unit of the U.S. Attorney's Office for the Southern District of Ohio. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, Defendants shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action case name and consolidated case numbers, to the Department of Justice and to EPA in accordance with Section XVIII (Notices) of this Consent Decree.

130. Failure to timely pay the civil penalty shall subject Defendants to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Defendants liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

131. Payment made pursuant to this Section is a penalty within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and is not a tax-deductible expenditure for purposes of federal law.

X. RESOLUTION OF CIVIL CLAIMS AGAINST DEFENDANTS

A. Resolution of the United States' Civil Claims.

132. Claims Based on Modifications Occurring Before the Date of Lodging of this Consent Decree. Entry of this Decree shall resolve all civil claims of the United States against Defendants that arose from any modifications commenced at any AEP Eastern System Unit prior to the Date of Lodging of this Consent Decree, including but not limited to, those modifications alleged in the Notices of Violation and complaints filed in *AEP I* and *AEP II*, under any or all of: (a) Parts C or D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515; (b) Section 111 of the Clean Air Act, 42 U.S.C. § 7411, and 40 C.F.R. § 60.14; (c) the federally-approved and enforceable Indiana State Implementation Plan, Kentucky State Implementation Plan, Ohio State Implementation Plan, Virginia State Implementation Plan, and West Virginia State Implementation Plan; or (d) Sections 502(a) and 504(a) of Title V of the Clean Air Act, 42 U.S.C §§ 7611(a) and 7611(c), but only to the extent that such claims are based on Defendants' failure to obtain an operating permit that reflects applicable requirements imposed under Parts C or D of Subchapter I, or Section 111 of the Clean Air Act.

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree also shall resolve all civil claims of the United States against Defendants that arise based on a modification commenced before December 31, 2018, or solely for Rockport Unit 2, before December 31, 2019, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of this Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act and under the regulations in effect as of the Date of Lodging of this Consent Decree, as alleged in the complaints in *AEP I* and *AEP II*.

134. Reopener. The resolution of the United States' civil claims against Defendants, as provided by this Subsection A, is subject to the provisions of Subsection B of this Section.

B. Pursuit by the United States of Civil Claims Otherwise Resolved by Subsection A.

135. Bases for Pursuing Resolved Claims for the AEP Eastern System. If Defendants violate: (a) the Eastern System-Wide Annual Tonnage Limitations for NO_x required pursuant to Paragraph 67; (b) the Eastern System-Wide Annual Tonnage Limitations for SO_2 required pursuant to Paragraph 86; or (c) operate a Unit more than ninety (90) days past a date established in this Consent Decree without completing the required installation, upgrade, or commencing Continuous Operation of any emission control device required pursuant to Paragraphs 68, 69, 87, 102, and 103 then the United States may pursue any claim at any AEP Eastern System Unit that is otherwise resolved under Subsection A (Resolution of United States' Civil Claims), subject to (a) and (b) below.

a. For any claims based on modifications undertaken at any Unit in the AEP Eastern System that is not an Improved Unit for the pollutant in question, claims may be pursued only where the modification(s) on which such claim is based was commenced within the five (5) years preceding the violation or failure specified in this Paragraph.

b. For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced: (1) after the Date of Lodging of this Consent Decree and (2) within the five (5) years preceding the violation or failure specified in this Paragraph.

136. Additional Bases for Pursuing Resolved Claims for Modifications at an Improved Unit. Solely with respect to an Improved Unit, the United States may also pursue claims arising

from a modification (or collection of modifications) at an Improved Unit that has otherwise been resolved under Subsection A (Resolution of the United States' Civil Claims) if the modification (or collection of modifications) at the Improved Unit on which such claim is based (a) was commenced after the Date of Lodging of this Consent Decree and (b) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

137. Any Other Unit can become an Improved Unit for NO_x if (a) it is equipped with an SCR, and (b) the operation of such SCR is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and incorporated into a Title V permit applicable to that Unit. Any Other Unit can become an Improved Unit for SO_2 if (a) it is equipped with an FGD, and (b) the operation of such FGD is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and incorporated into a Title V permit applicable to that Unit.

138. Additional Bases for Pursuing Resolved Claims for Modifications at Other Units.

a. Solely with respect to Other Units, i.e., a Unit that is not an Improved Unit under the terms of this Consent Decree, the United States may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that has otherwise been resolved under Subsection A (Resolution of the United States' Civil Claims), if the modification (or collection of modifications) at the Other Unit on which the claim is based was commenced within the five (5) years preceding any of the following events:

1. a modification (or collection of modifications) at such Other Unit commenced after the Date of Lodging of this Consent Decree increases the maximum hourly

emission rate for such Other Unit for the relevant pollutant (NO_x or SO_2) (as measured by 40 C.F.R. § 60.14(b) and (h));

2. the aggregate of all Capital Expenditures made at such Other Unit exceed \$125/KW on the Unit's Boiler Island (based on the generating capacities identified in Paragraph 7) during the period from the Date of Entry of this Consent Decree through December 31, 2015. (Capital Expenditures shall be measured in calendar year 2007 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

3. a modification (or collection of modifications) at such Other Unit commenced after the Date of Lodging of this Consent Decree results in an emissions increase of NO_x and/or SO_2 at such Other Unit, and such increase: (i) presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603; (ii) causes or contributes to violation of a NAAQS in any Air Quality Control Area that is in attainment with that NAAQS; (iii) causes or contributes to violation of a PSD increment; or (iv) causes or contributes to any adverse impact on any formally-recognized air quality and related values in any Class I area. The introduction of any new or changed NAAQS shall not, standing alone, provide the showing needed under Subparagraphs (3)(ii) or (3)(iii) of this Paragraph, to pursue any claim for a modification at an Other Unit resolved under Subparagraph A of this Section.

b. Solely with respect to Other Units at the plant listed below, the United States may also pursue claims arising from a modification (or collection of modifications) at such Other Units commenced after the Date of Lodging of this Consent Decree if such modification (or collection of modifications) results in an emissions increase of SO_2 at such Other Unit, and such increase causes the emissions at the plant at issue to exceed the Plant-Wide Annual Rolling

Average Tonnage Limitation for SO_2 at Clinch River listed in the table below for year 2010-2014 and/or 2015 and beyond:

Plant	Year	SO_2 Tons Limit
Clinch River	2010 - 2014	21,700
Clinch River	2015 and each year thereafter	16,300

C. Resolution of Past Claims of the States and Citizen Plaintiffs and Reservation of Rights.

139. The States and Citizen Plaintiffs agree that this Consent Decree resolves all civil claims that have been alleged in their respective complaints or could have been alleged against Defendants prior to the Date of Lodging of this Consent Decree for violations of: (a) Parts C or D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515, and (b) Section 111 of the Act, 42 U.S.C. § 7411, and 40 C.F.R § 60.14, at Units within the AEP Eastern System.

140. The States and Citizen Plaintiffs expressly do not join in giving the Defendants the covenant provided by the United States through Paragraph 133 of this Consent Decree, do not release any claims under the Clean Air Act and its implementing regulations arising after the Date of Lodging of this Consent Decree, and reserve their rights, if any, to bring any actions against the Defendants pursuant to 42 U.S.C. § 7604 for any claims arising after the Date of Lodging of this Consent Decree.

141. Notwithstanding Paragraph 140, the States and Citizen Plaintiffs release Defendants from any civil claim that may arise under the Clean Air Act for Defendants' performance of activities that this Consent Decree expressly directs Defendants to undertake,

except to the extent that such activities would cause a significant increase in the emission of a criteria pollutant other than SO_2, NO_x, or PM.

142. Retention of Authority Regarding NAAQS Exceedences. Nothing in this Consent Decree shall be construed to affect the authority of the United States or any state under applicable federal statutes or regulations and applicable state statutes or regulations to impose appropriate requirements or sanctions on any Unit in the AEP Eastern System, including, but not limited to, the Units at the Clinch River plant, if the United States or a state determines that emissions from any Unit in the AEP Eastern System result in violation of, or interfere with the attainment and maintenance of, any ambient air quality standard.

XI. PERIODIC REPORTING

143. Beginning on March 31, 2008, and continuing annually thereafter on March 31 until termination of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Defendants shall submit to the Unites States, the States, and the Citizen Plaintiffs a progress report in compliance with Appendix B of this Consent Decree.

144. In any periodic progress report submitted pursuant to this Section, Defendants may incorporate by reference information previously submitted under their Title V permitting requirements, provided that Defendants attach the Title V permit report, or the relevant portion thereof, and provide a specific reference to the provisions of the Title V permit report that are responsive to the information required in the periodic progress report.

145. In addition to the progress reports required pursuant to this Section, Defendants shall provide a written report to the United States, the States, and the Citizen Plaintiffs of any violation of the requirements of this Consent Decree within fifteen (15) days of when Defendants knew or should have known of any such violation. In this report, Defendants shall explain the

cause or causes of the violation and all measures taken or to be taken by Defendants to prevent such violations in the future.

146. Each report shall be signed by Defendants' Vice President of Environmental Services or his or her equivalent or designee of at least the rank of Vice President, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

147. If any SO_2 or NO_x Allowances are surrendered to any third party pursuant to this Consent Decree, the third party's certification pursuant to Paragraphs 83 and 95 shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that, _____________ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

XII. REVIEW AND APPROVAL OF SUBMITTALS

148. Defendants shall submit each plan, report, or other submission required by this Consent Decree to the Plaintiffs specified, whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. The Plaintiff(s) to whom the report is submitted, as required, may approve the submittal or decline to approve it and provide written comments explaining the bases for declining such approval as soon as reasonably practicable. Such Plaintiff(s) will endeavor to coordinate their comments into one document when explaining their bases for declining such approval. Within sixty (60) days of receiving written comments from any of the Plaintiff(s), Defendants shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal to the Plaintiff(s); or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XV (Dispute Resolution) of this Consent Decree.

149. Upon receipt of Plaintiffs' or Plaintiff's (as the case may be) final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, Defendants shall implement the approved submittal in accordance with the schedule specified therein.

XIII. STIPULATED PENALTIES

150. For any failure by Defendants to comply with the terms of this Consent Decree, and subject to the provisions of Sections XIV (Force Majeure) and XV (Dispute Resolution), Defendants shall pay, within thirty (30) days after receipt of written demand to Defendants by the United States, the following stipulated penalties to the United States:

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
a. Failure to pay the civil penalty as specified in Section IX (Civil Penalty) of this Consent Decree	$10,000 per day
b. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500 per day per violation
c. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000 per day per violation
d. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000 per day per violation

Consent Decree Violation	Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)
e. Failure to comply with the Eastern System-Wide Annual Tonnage Limitation for SO_2	\$5,000 per ton for the first 1000 tons, and \$10,000 per ton for each additional ton above 1000 tons, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
f. Failure to comply with the Plant-Wide Annual Rolling Tonnage Limitation for SO_2 at Clinch River	\$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
g. Failure to comply with the Eastern System-Wide Annual Tonnage Limitation for NO_x	\$5,000 per ton for the first 1000 tons, and \$10,000 per ton for each additional ton above 1000 tons, plus the surrender, pursuant to the procedures set forth in Paragraphs 82 and 83, of NO_x Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
h. Failure to install, commence operation, or Continuously Operate a pollution control device required under this Consent Decree	\$10,000 per day per violation during the first 30 days, \$32,500 per day per violation thereafter
i. Failure to Retire, Retrofit, or Re-power a Unit by the date specified in this Consent Decree	\$10,000 per day per violation during the first 30 days, \$32,500 per day per violation thereafter

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
j. Failure to install or operate CEMS as required in this Consent Decree	$1,000 per day per violation
k. Failure to conduct performance tests of PM emissions, as required in this Consent Decree	$1,000 per day per violation
l. Failure to apply for any permit required by Section XVI (Permits)	$1,000 per day per violation
m. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required in this Consent Decree	$750 per day per violation during the first ten days, $1,000 per day per violation thereafter
n. Using NO_x Allowances except as permitted by Paragraphs 75, 76, and 78	The surrender of NO_x Allowances in an amount equal to four times the number of NO_x Allowances used in violation of this Consent Decree
o. Failure to surrender NO_x Allowances as required by Paragraphs 75 and 79	(a) $32,500 per day plus (b) $7,500 per NO_x Allowance not surrendered
p. Failure to surrender SO_2 Allowances as required by Paragraph 93	(a) $32,500 per day plus (b) $1,000 per SO_2 Allowance not surrendered
q. Failure to demonstrate the third party surrender of an SO_2 Allowance or NO_x Allowance in accordance with Paragraphs 95-96 and 82-83.	$2,500 per day per violation
r. Failure to implement any of the Environmental Mitigation Projects described in Appendix A in compliance with Section VIII (Environmental Mitigation Projects) of this Consent Decree	The difference between the cost of the Project, as identified in Appendix A, and the dollars Defendants spent to implement the Project

Consent Decree Violation	Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)
s. Failure to fund an Environmental Mitigation Project, as submitted by the States, in compliance with Section VIII (Environmental Mitigation Projects) of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
t. Failure to Continuously Operate required Other NO_x Pollution Controls required in Paragraph 69	$10,000 per day during the first 30 days, and $32,500 each day thereafter
u. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96 of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
v. Any other violation of this Consent Decree	$1,000 per day per violation

151. Violation of an Emission Rate or 30-Day Rolling Average Removal Efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based. Where a violation of a 30-Day Rolling Average Emission Rate or 30-Day Rolling Average Removal Efficiency (for the same pollutant and from the same source) recurs within periods of less than thirty (30) days, Defendants shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

152. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases, whichever is applicable. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

153. Defendants shall pay all stipulated penalties to the United States within thirty (30) days of receipt of written demand to Defendants from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s) no longer continues, unless Defendants elect within twenty (20) days of receipt of written demand to Defendants from the United States to dispute the accrual of stipulated penalties in accordance with the provisions in Section XV (Dispute Resolution) of this Consent Decree.

154. Stipulated penalties shall continue to accrue as provided in accordance with Paragraph 152 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement, or by a decision of Plaintiffs pursuant to Section XV (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid within thirty (30) days of the effective date of the agreement or of the receipt of Plaintiffs' decision;

b. If the dispute is appealed to the Court and Plaintiffs prevail in whole or in part, Defendants shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with interest accrued on such penalties determined by the Court to be owing, except as provided in Subparagraph c, below;

c. If the Court's decision is appealed by any Party, Defendants shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued stipulated penalties determined to be owing, together with interest accrued on such stipulated penalties determined to be owing by the appellate court.

Notwithstanding any other provision of this Consent Decree, the accrued stipulated penalties agreed by the Plaintiffs and Defendants, or determined by the Plaintiffs through Dispute Resolution, to be owing may be less than the stipulated penalty amounts set forth in Paragraph 150.

155. All stipulated penalties shall be paid in the manner set forth in Section IX (Civil Penalty) of this Consent Decree.

156. Should Defendants fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

157. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to Plaintiffs by reason of Defendants' failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree provides for payment of a stipulated penalty, Defendants shall be allowed a credit for stipulated penalties paid against any statutory penalties also imposed for such violation.

XIV. FORCE MAJEURE

158. For purposes of this Consent Decree, including, but not limited to, Paragraphs 67 and 86, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of Defendants or any entity controlled by Defendants that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite Defendants' best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

159. Notice of Force Majeure Events. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which Defendants intend to assert a claim of Force Majeure, Defendants shall notify the Plaintiffs in writing as soon as practicable, but in no event later than twenty-one (21) business days following the date Defendants first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, Defendants shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by Defendants to prevent or minimize the delay or violation, the schedule by which Defendants propose to implement those measures, and Defendants' rationale for attributing a delay or violation to a Force Majeure Event. Defendants shall adopt all reasonable measures to avoid or minimize such delays or violations. Defendants shall be deemed to know of any circumstance which Defendants or any entity controlled by Defendants knew or should have known.

160. Failure to Give Notice. If Defendants materially fail to comply with the notice requirements of this Section, the Plaintiffs may void Defendants' claim for Force Majeure as to the specific event for which Defendants have failed to comply with such notice requirement.

161. Plaintiffs' Response. The Plaintiffs shall notify Defendants in writing regarding Defendants' claim of Force Majeure as soon as reasonably practicable. If the Plaintiffs agree that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event, or the extent to which Defendants may be relieved of stipulated penalties or other remedies provided under the terms of this Consent Decree. Such agreement shall be reduced to writing, and signed by all Parties. If the agreement results in a material change to the terms of this Consent Decree, an appropriate modification shall be made pursuant to Section XXII (Modification). If such change is not material, no modification of this Consent Decree shall be required.

162. Disagreement. If Plaintiffs do not accept Defendants' claim of Force Majeure, or if the Plaintiffs and Defendants cannot agree on the length of the delay actually caused by the Force Majeure Event, or the extent of relief required to address the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section XV (Dispute Resolution) of this Consent Decree.

163. Burden of Proof. In any dispute regarding Force Majeure, Defendants shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. Defendants shall also bear the burden of proving that Defendants gave the notice required by this Section and the burden of proving the anticipated duration and extent of any delay(s) attributable to a

Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

164. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of Defendants' obligations under this Consent Decree shall not constitute a Force Majeure Event.

165. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and Defendants' response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; unanticipated coal supply or pollution control reagent delivery interruptions; acts of God; acts of war or terrorism; and orders by a government official, government agency, other regulatory authority, or a regional transmission organization, acting under and authorized by applicable law, that directs Defendants to operate an AEP Eastern System Unit in response to a local or system-wide (state-wide or regional) emergency (which could include unanticipated required operation to avoid loss of load or unserved load). Depending upon the circumstances and Defendants' response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of Defendants and Defendants have taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority.

166. As part of the resolution of any matter submitted to this Court under Section XV (Dispute Resolution) of this Consent Decree regarding a claim of Force Majeure, the Plaintiffs and Defendants by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the Plaintiffs or approved by the Court. Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance with the extended or modified schedule (provided that Defendants shall not be precluded from making a further claim of Force Majeure with regard to meeting any such extended or modified schedule).

XV. DISPUTE RESOLUTION

167. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Parties.

168. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Parties advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Parties receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

169. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) days from the date of the first meeting among the disputing Parties' representatives unless they agree in writing to shorten or extend

this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually agreed upon alternative dispute resolution (ADR) forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period (or such longer period as the Parties may agree to in writing).

170. If the disputing Parties are unable to reach agreement during the informal negotiation period, the Plaintiffs shall provide Defendants with a written summary of their position regarding the dispute. The written position provided by Plaintiffs shall be considered binding unless, within forty-five (45) days thereafter, Defendants seek judicial resolution of the dispute by filing a petition with this Court. The Plaintiffs may respond to the petition within forty-five (45) days of filing. In their initial filings with the Court under this Paragraph, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

171. The time periods set out in this Section may be shortened or lengthened upon motion to the Court of one of the Parties to the dispute, explaining the Party's basis for seeking such a scheduling modification.

172. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

173. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance

with the extended or modified schedule, provided that Defendants shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

174. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 170, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

XVI. PERMITS

175. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Defendants to secure a permit to authorize construction or operation of any device contemplated herein, including all preconstruction, construction, and operating permits required under state law, Defendants shall make such application in a timely manner. Defendants shall provide Notice to Plaintiffs under Section XVIII (Notices), for each Unit that Defendants submit an application for any permit described in this Paragraph 175.

176. Notwithstanding the previous Paragraph, nothing in this Consent Decree shall be construed to require Defendants to apply for or obtain a PSD or Nonattainment NSR permit for physical changes in, or changes in the method of operation of, any AEP Eastern System Unit that would give rise to claims resolved by Paragraph 132 and 133, subject to Paragraphs 134 through 138, or Paragraphs 139 and 141 of this Consent Decree.

177. When permits are required as described in Paragraph 175, Defendants shall complete and submit applications for such permits to the appropriate authorities to allow time for all legally required processing and review of the permit request, including requests for additional

information by the permitting authorities. Any failure by Defendants to submit a timely permit application for any Unit in the AEP Eastern System shall bar any use by Defendants of Section XIV (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

178. Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term or limit has or will become part of a Title V permit, subject to the terms of Section XXVI (Conditional Termination of Enforcement Under Decree) of this Consent Decree.

179. Within three (3) years from the Date of Entry of this Consent Decree, and in accordance with federal and/or state requirements for modifying or renewing a Title V permit, Defendants shall amend any applicable Title V permit application, or apply for amendments to their Title V permits, to include a schedule for any Unit-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, required emission rates or other limitations. For Units subject to a requirement to Retire, Retrofit, or Re-power, Defendants shall apply to modify, renew, or obtain any applicable Title V permit to include a schedule for any Unit-specific performance, operation, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, required emission rates or other limitations, within (12) twelve months of making such election to Retire, Retrofit, or Re-power.

180. Within one (1) year from commencement of operation of each pollution control device to be installed, upgraded, and/or operated under this Consent Decree, Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree into federally-enforceable non-Title V permits and/or site-specific amendments to the applicable state implementation plans to reflect all new requirements applicable to each Unit in the AEP Eastern System, the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer.

181. Defendants shall provide the United States with a copy of each application for a federally-enforceable non-Title V permit or amendment to a state implementation plan, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment period.

182. Prior to termination of this Consent Decree, Defendants shall obtain enforceable provisions in their Title V permits for the AEP Eastern System that incorporate (a) any Unit-specific requirements and limitations of this Consent Decree, such as performance, operational, maintenance, and control technology requirements, (b) the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River and the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and (c) the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x. If Defendants do not obtain enforceable provisions for the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x in such Title V permits, then the requirements in Paragraphs 86 and 67 shall remain enforceable under this Consent Decree and shall not be subject to termination.

183. If Defendants sell or transfer to an entity unrelated to Defendants ("Third-Party Purchaser") part or all of Defendants' Ownership Interest in a Unit in the AEP Eastern System,

Defendants shall comply with the requirements of Section XIX (Sales or Transfers of Operational or Ownership Interests) with regard to that Unit prior to any such sale or transfer unless, following any such sale or transfer, Defendants remain the holder of the Title V permit for such facility.

XVII. INFORMATION COLLECTION AND RETENTION

184. Any authorized representative of the United States, including attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the AEP Eastern System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by Defendants or their representatives, contractors, or consultants; and

d. assessing Defendants' compliance with this Consent Decree.

185. Defendants shall retain, and instruct their contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in their or their contractors' or agents' possession or control (with the exception of their contractors' copies of field drawings and specifications), and that directly relate to Defendants' performance of their obligations under this Consent Decree until six (6) years following completion of performance of such obligations. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

186. All information and documents submitted by Defendants pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of

documents unless (a) the information and documents are subject to legal privileges or protection or (b) Defendants claim and substantiate in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

187. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Defendants' facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations, or permits.

XVIII. NOTICES

188. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611
DJ# 90-5-2-1-06893

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [Mail Code 2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Air Enforcement & Compliance Assurance Branch
U.S. EPA Region V
77 W. Jackson St.
Mail Code AE17J
Chicago, IL 60604

and

Air Protection Division Director
U.S. EPA Region III
1650 Arch Street
Philadelphia, PA 19103

<u>As to the State of Connecticut:</u>

Office of the Attorney General
Environmental Department
P.O. Box 120
Hartford, Connecticut
06141-0120

<u>As to the State of Maryland:</u>

Frank Courtright
Program Manager
Air Quality Compliance Program
Maryland Department of the Environment
1800 Washington Blvd.
Baltimore, Maryland 21230
fcourtright@mde.state.md.us

<u>As to the Commonwealth of Massachusetts:</u>

Frederick D. Augenstern, Assistant Attorney General
Office of the Attorney General
1 Ashburton Place, 18th floor
Boston, Massachusetts 02108
fred.augenstern@state.ma.us

and

Douglas Shallcross, Esquire
Department of Environmental Protection
Office of General Counsel
1 Winter Street
Boston, Massachusetts 02108
Douglas.Shallcross@state.ma.us

As to the State of New Hampshire:

Director, Air Resources Division
New Hampshire Department of Environmental Services
29 Hazen Dive
Concord, New Hampshire 03302-0095

As to the State of New Jersey:

Kevin P. Auerbacher
Section Chief
Environmental Enforcement Section
R.J. Hughes Justice Complex
25 Market Street
P.O. Box 093
Trenton, New Jersey 08625-0093

As to the State of New York:

Robert Rosenthal
Assistant Attorney General
New York State Attorney General's Office
The Capitol
Albany, New York 12224

As to the State of Rhode Island:

Tricia K. Jedele
Special Assistant Attorney General
150 South Main Street
Providence, RI 02903
(401) 274-4400, Ext. 2400
tjedele@riag.ri.gov

As to the State of Vermont:

Environmental Division
Office of the Attorney General
109 State Street
Montpelier, Vermont 05609-1001

and

Director
Air Pollution Control Division
Department of Environmental Conservation
Agency of Natural Resources
Building 3 South
103 South Main Street
Waterbury, Vermont 05671-0402

As to the Citizen Plaintiffs:

Nancy S. Marks
Natural Resources Defense Council, Inc.
40 West 20th Street
New York, New York 10011
(212) 727-4414
nmarks@nrdc.org

and

Albert F. Ettinger
Environmental Law and Policy Center
35 East Wacker Dr. Suite 1300
Chicago, Illinois 60601-2110
(312) 673-6500
aettinger@elpc.org

As to Defendants:

Vice President, Environmental Services
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215
jmmcmanus@aep.com

and

General Counsel
American Electric Power
1 Riverside Plaza
Columbus, OH 43215
jbkeane@aep.com

189. All notifications, communications, or submissions made pursuant to this Section shall be sent as follows: (a) by overnight mail or overnight delivery service to the United States;

and (b) by electronic mail to all Plaintiffs, if practicable, but if not practicable, then by overnight mail or overnight delivery service to the States and Citizen Plaintiffs. All notifications, communications, and transmissions sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service.

190. Any Party may change either the notice recipient or the address for providing notices to it by serving all other Parties with a notice setting forth such new notice recipient or address.

XIX. SALES OR TRANSFERS OF OPERATIONAL OR OWNERSHIP INTERESTS

191. If Defendants propose to sell or transfer an Operational or Ownership Interest to an entity unrelated to Defendants ("Third Party"), they shall advise the Third Party in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree at least sixty (60) days before such proposed sale or transfer.

192. No sale or transfer of an Operational or Ownership Interest shall take place before the Third Party and Plaintiffs have executed, and the Court has approved, a modification pursuant to Section XXII (Modification) of this Consent Decree making the Third Party a party to this Consent Decree and jointly and severally liable with Defendants for all the requirements of this Decree that may be applicable to the transferred or purchased Interests.

193. This Consent Decree shall not be construed to impede the transfer of any Interests between Defendants and any Third Party so long as the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation – as between Defendants and any Third Party – of the burdens of compliance with this Decree,

provided that both Defendants and such Third Party shall remain jointly and severally liable for the obligations of the Consent Decree applicable to the transferred or purchased Interests.

194. If the Plaintiffs agree, the Plaintiffs, Defendants, and the Third Party that has become a party to this Consent Decree pursuant to Paragraph 192, may execute a modification that relieves Defendants of liability under this Consent Decree for, and makes the Third Party liable for, all obligations and liabilities applicable to the purchased or transferred Interests. Notwithstanding the foregoing, however, Defendants may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Interests, including the obligations set forth in Section VIII (Environmental Mitigation Projects), Paragraphs 86 and 67, and Section IX (Civil Penalty).

195. Defendants may propose and Plaintiffs may agree to restrict the scope of joint and several liability of any purchaser or transferee for any AEP Eastern System obligations to the extent such obligations may be adequately separated in an enforceable manner using the methods provided by or approved under Section XVI (Permits).

196. Paragraphs 191-195 of this Consent Decree do not apply if an Interest is sold or transferred solely as collateral security in order to consummate a financing arrangement (not including a sale-leaseback), so long as Defendants: (a) remain the operator (as that term is used and interpreted under the Clean Air Act) of the subject AEP Eastern System Unit(s); (b) remain

subject to and liable for all obligations and liabilities of this Consent Decree; and (c) supply Plaintiffs with the following certification within thirty (30) days of the sale or transfer:

> "Certification of Change in Ownership Interest Solely for Purpose of Consummating Financing. We, the Chief Executive Officer and General Counsel of American Electric Power ("AEP"), hereby jointly certify under Title 18 U.S.C. Section 1001, on our own behalf and on behalf of AEP, that any change in AEP's Ownership Interest in any AEP Eastern System Unit that is caused by the sale or transfer as collateral security of such Ownership Interest in such Unit(s) pursuant to the financing agreement consummated on [insert applicable date] between AEP and [insert applicable entity]: a) is made solely for the purpose of providing collateral security in order to consummate a financing arrangement; b) does not impair AEP's ability, legally or otherwise, to comply timely with all terms and provisions of the Consent Decree entered in *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action No. C2-99-1250 ("AEP I") and *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-04-1098 and C2-05-360 ("AEP II"); c) does not affect AEP's operational control of any Unit covered by that Consent Decree in a manner that is inconsistent with AEP's performance of its obligations under the Consent Decree; and d) in no way affects the status of AEP's obligations or liabilities under that Consent Decree."

XX. EFFECTIVE DATE

197. The effective date of this Consent Decree shall be the Date of Entry.

XXI. RETENTION OF JURISDICTION

198. The Court shall retain jurisdiction of this case after the Date of Entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, any Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXII. MODIFICATION

199. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Where the modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court.

XXIII. GENERAL PROVISIONS

200. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The limitations and requirements set forth herein do not relieve Defendants from any obligation to comply with other state and federal requirements under the Clean Air Act at any Units covered by this Consent Decree, including the Defendants' obligation to satisfy any state modeling requirements set forth in a state implementation plan.

201. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

202. In any subsequent administrative or judicial action initiated by any of the Plaintiffs for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Defendants shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by any of the Plaintiffs in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph affects the validity of Paragraphs Paragraph 132 and 133, subject to Paragraphs 134 through 138, or Paragraphs 139 and 141.

203. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Defendants of their obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Section X (Resolution of Civil

Claims Against Defendants), nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the Plaintiffs to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

204. At any time prior to termination of this Consent Decree, Defendants may request approval from Plaintiffs to implement other control technology for SO_2 or NO_x than what is required by this Consent Decree. In seeking such approval, Defendants must demonstrate that such alternative control technology is capable of achieving pollution reductions equivalent to an FGD (for SO_2) or SCR (for NO_x) at the Units in the AEP Eastern System at which Defendants seek approval to implement such other control technology for SO_2 or NO_x. Approval of such a request is solely at the discretion of the Plaintiffs.

205. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8314 (Feb. 24, 1997)) concerning the use of data for any purpose under the Act generated either by the reference methods specified herein or otherwise.

206. Each limit and/or other requirement established by or under this Consent Decree is a separate, independent requirement.

207. Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. Defendants shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending upon whether the limit is expressed to three or two significant digits. For example, if an actual

Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. Defendants shall report data to the number of significant digits in which the standard or limit is expressed.

208. This Consent Decree does not limit, enlarge, or affect the rights of any Party to this Consent Decree as against any third parties.

209. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supersedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

210. Except for Citizen Plaintiffs, each Party to this action shall bear its own costs and attorneys' fees. Defendants shall reimburse the Citizen Plaintiffs' attorneys' fees and costs, pursuant to 42 U.S.C. § 7604(d), and the agreement between counsel for Defendants and Citizen Plaintiffs within thirty (30) days of the Date of Entry of this Consent Decree.

XXIV. SIGNATORIES AND SERVICE

211. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

212. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

213. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXV. PUBLIC COMMENT

214. The Parties agree and acknowledge that final approval by the United States and the entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate. The Defendants shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified the Defendants, in writing, that the United States no longer supports entry of the Consent Decree.

XXVI. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

215. Termination as to Completed Tasks. As soon as Defendants complete a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, Defendants may, by motion to this Court, seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

216. Conditional Termination of Enforcement Through the Consent Decree. After Defendants:

a. have successfully completed construction, and have maintained Continuous Operation, of all pollution controls as required by this Consent Decree;

b. have obtained final Title V permits (i) as required by the terms of this Consent Decree; (ii) that cover all Units in this Consent Decree; and (iii) that include as enforceable permit terms all of the Unit performance and other requirements specified in this Consent Decree; and

c. certify that the date is later than December 31, 2022;

then Defendants may so certify these facts to the Plaintiffs and this Court. If the Plaintiffs do not object in writing with specific reasons within forty-five (45) days of receipt of Defendants' certification, then, for any Consent Decree violations that occur after the filing of notice, the Plaintiffs shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

217. Resort to Enforcement under this Consent Decree. Notwithstanding Paragraph 216, if enforcement of a provision in this Consent Decree cannot be pursued by a Party under the applicable Title V permit, or if a Consent Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Consent Decree at any time.

XXVII. FINAL JUDGMENT

218. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment among the Parties.

IT IS SO ORDERED, this __10th__ day of December, 2007.

EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE UNITED STATES:

RONALD J. TENPAS
Acting Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

W. BENJAMIN FISHEROW
Deputy Chief
Environmental Enforcement Section

PHILIP A. BROOKS
Counsel to the Chief

JUSTIN A. SAVAGE
THOMAS A. MARIANI
Assistant Chief
JAMES A. LOFTON
Senior Counsel
MARC BORODIN
JENNIFER A. LUKAS-JACKSON
THOMAS A. BENSON
KATHERINE L. VANDERHOOK
DEBORAH BEHLES
MYLES E. FLINT, II
Trial Attorneys
LESLIE B. BELLAS
By Special Appointment as a Department of Justice Attorney
Environmental Enforcement Section
Environmental and Natural Resources Division

Signature Page for Consent Decree in:

United States of America
v.
American Electric Power Service Corp , et al.

FOR THE UNITED STATES OF AMERICA:

GREGORY G. LOCKHART
United States Attorney
Southern District of Ohio

MARK D'ALESSANDRO
Assistant United States Attorney
Southern District of Ohio
United States Department of Justice

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE UNITED STATES:

Granta Y. Nakayama

GRANTA Y. NAKAYAMA
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Walker B. Smith

WALKER B. SMITH
Director, Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Adam M. Kushner

ADAM M. KUSHNER
Acting Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Ilana S. Saltzbart

ILANA S. SALTZBART
EDWARD MESSINA
Attorney-Advisor

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

MARY A. GADE
Regional Administrator
Region 5
U.S. Environmental Protection Agency

ROBERT A. KAPLAN
Regional Counsel
Region 5
U.S. Environmental Protection Agency

STEPHEN ROTHBLATT
Director
Air and Radiation Division
Region 5
U.S. Environmental Protection Agency

SABRINA ARGENTIERI
Associate Regional Counsel
Region 5
U.S. Environmental Protection Agency

Signature Page for Consent Decree in:

United States et al.,
v.
American Electric Power Service Corp., et al.

Donald S. Welsh
DONALD S. WELSH
Regional Administrator
U.S. EPA Region III

Margaret Hottenson
for WILLIAM C. EARLY
Regional Counsel
U.S. EPA Region III

Donna L. Mastro
DONNA L. MASTRO
Senior Assistant Regional Counsel
U.S. EPA Region III

Douglas J. Snyder
DOUGLAS J. SNYDER
Senior Assistant Regional Counsel
U.S. EPA Region III

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF CONNECTICUT:

RICHARD BLUMENTHAL
Attorney General

KIMBERLY MASSICOTTE
Assistant Attorney General

JOSE A. SUAREZ
Assistant Attorney General

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF MARYLAND:

SHARI T. WILSON, Secretary
Maryland Department of the Environment
1800 Washington Blvd.
Baltimore, Maryland 21230

DOUGLAS F. GANSLER
Attorney General of Maryland

MATTHEW ZIMMERMAN
Assistant Attorney General
Office of the Attorney General
1800 Washington Blvd.
Baltimore, Maryland 21230
410-537-3452

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE COMMONWEALTH OF MASSACHUSETTS:

MARTHA COAKLEY
ATTORNEY GENERAL

FREDERICK D. AUGENSTERN
Assistant Attorney General
Environmental Protection Division
1 Ashburton Place, 18th Floor
Boston, Massachusetts 02108
(617) 727-2200 ext. 2427

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF NEW HAMPSHIRE:

Maureen D. Smith

MAUREEN D. SMITH
Senior Assistant Attorney General
33 Capitol Street
Concord, New Hampshire 03301

K. ALLEN BROOKS
Assistant Attorney General
33 Capitol Street
Concord, New Hampshire 03301

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF NEW JERSEY:

Very Truly Yours,

ANNE MILGRAM
ATTORNEY GENERAL OF NEW JERSEY

By: Jon C. Martin
Jon C. Martin
Deputy Attorney General

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF NEW YORK:

ANDREW M. CUOMO
Attorney General

KATHERINE KENNEDY
Special Deputy Attorney General
for Environmental Protection

ROBERT ROSENTHAL
MICHAEL J. MYERS
Assistant Attorneys General
Environmental Protection Bureau
The Capitol
Albany, New York 12224
(518) 402-2260
Of counsel

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF RHODE ISLAND:

PATRICK C. LYNCH
Attorney General

TRICIA K. JEDELE
Special Assistant Attorney General
150 South Main Street
Providence, Rhode Island 02903
Of counsel

Signature Page for Consent Decree in:

United States, et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF VERMONT:

WILLIAM H. SORRELL
ATTORNEY GENERAL
STATE OF VERMONT

KEVIN O. LESKE
ERICK TITRUD
Assistant Attorneys General
Environmental Division
109 State Street
Montpelier, VT 05609-1001

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR CITIZEN PLAINTIFFS:

Nancy S Marks

NANCY S. MARKS
Natural Resources Defense Council, Inc.
40 West 20th Street
New York, New York 10011
(212) 727-4414

For Citizen Plaintiffs Sierra Club and
Natural Resources Defense Council, Inc.

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR CITIZEN PLAINTIFFS:

ALBERT F. ETTINGER
Environmental Law & Policy Center
35 East Wacker Drive, Suite 1300
Chicago, Illinois 60601-2110

For Citizen Plaintiffs Ohio Citizen Action,
CitizensAction Coalition of Indiana,
Hoosier Environmental Council,
Ohio Valley Environmental Coalition,
West Virginia Environmental Council,
Clean Air Council,
Izaak Walton League of America,
United States Public Interest Research Group,
National Wildlife Federation,
Indiana Wildlife Federation
and League of Ohio Sportsmen

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR CITIZEN PLAINTIFFS:

STEPHEN P. SAMUELS, Ohio Bar #0007979
Schottenstein, Zox & Dunn Co., LPA
P.O. Box 165020
Columbus, Ohio 43216-5020
(614) 462-5021

Local Counsel for Sierra Club and
Natural Resources Defense Council, Inc. Ohio Citizen Action, Citizens Action Coalition of Indiana, Hoosier EnvironmentalCouncil, Ohio Valley Environmental Coalition, West Virginia Environmental Council, Clean Air Council, Izaak Walton League of America, United States Public Interest Research Group, National Wildlife Federation, Indiana Wildlife Federation, and League of Ohio Sportsmen

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR DEFENDANTS AMERICAN ELECTRIC POWER SERVICE CORPORATION, ET AL.:

NICHOLAS K. AKINS
Executive Vice President – Generation

APPENDIX A
ENVIRONMENTAL MITIGATION PROJECTS

In compliance with and in addition to the requirements in Section VIII of this Consent Decree (Environmental Mitigation Projects), Defendants shall comply with the requirements of this Appendix to ensure that the benefits of the $36 million in federally directed Environmental Mitigation Projects are achieved.

I. National Parks Mitigation

A. Within 45 days from the Date of Entry, Defendants shall pay to the National Park Service the sum of $2 million to be used in accordance with the Park System Resource Protection Act, 16 U.S.C. § 19jj, for the restoration of land, watersheds, vegetation, and forests using adaptive management techniques designed to improve ecosystem health and mitigate harmful effects from air pollution. This may include reforestation or restoration of native species and acquisition of equivalent resources and support for collaborative initiatives with state and local agencies and other stakeholders to develop plans to assure resource protection over the long-term. Projects will focus on one or more of the following Class I areas alleged in the underlying action to have been injured by emissions from Defendants facilities: Shenandoah National Park, Mammoth Cave National Park, and Great Smoky Mountains National Park.

B. Payment of the amount specified in the preceding paragraph shall be made to the Natural Resource Damage and Assessment Fund managed by the United States Department of the Interior. Instructions for transferring funds will be provided to the Defendants by the National Park Service. Notwithstanding Section I.A of this Appendix, payment of funds by Defendants is not due until ten (10) days after receipt of payment instructions.

C. Upon payment of the required funds into the Natural Resource Damage and Assessment Fund, Defendants shall have no further responsibilities regarding the implementation of any project selected by the National Park Service in connection with this provision of the Consent Decree.

II. Overall Environmental Mitigation Project Schedule and Budget

A. Within 120 days of the Date of Entry, as further described below, Defendants shall submit plans to EPA for review and approval for completing the remaining $34 million in federally directed Environmental Mitigation Projects specified in this Appendix over a period of not more than five (5) years from the Date of Entry. EPA will consult with the Citizen Plaintiffs, through their counsel, prior to approving or commenting on any proposed plan. The Parties agree that Defendants are entitled to spread their payments for Environmental Mitigation Projects evenly over the five-year period commencing upon the Date of Entry. Defendants are not, however, precluded from accelerating payments to better effectuate a proposed mitigation plan, provided however, Defendants shall not be entitled to any reduction in the nominal amount of the required payments by virtue of the early expenditures. EPA may, but is not required to, approve a proposed Project budget that results in a back-loading of some expenditures. EPA shall determine prior to approval that all Projects are consistent with federal law.

B. Defendants may, at their election, consolidate the plans required by this Appendix into a single plan.

C. In addition to the requirements set forth below, Defendants shall submit within 120 days of the Date of Entry, a summary-level budget and Project time-line that covers all of the Projects proposed.

D. Beginning March 31, 2008, and continuing on March 31 of each year thereafter until completion of each Project (including any applicable periods of demonstration or testing), Defendants shall provide the United States and Citizen Plaintiffs with written reports detailing the progress of each Project, including Project Dollars.

E. Within 60 days following the completion of each Project required under Appendix A, Defendants shall submit to the United States and Citizen Plaintiffs a report that documents the date that the Project was completed, the results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Defendants in implementing the Project.

F. Upon approval of the plans required by this Appendix by EPA, Defendants shall complete the Environmental Mitigation Projects according to the approved plans. Nothing in this Consent Decree shall be interpreted to prohibit Defendants from completing Environmental Mitigation Projects before the deadlines specified in the schedule of an approved plan.

III. Acquisition and Restoration of Ecologically Significant Areas in Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia

A. Within 120 days of the Date of Entry, and on each anniversary of the initial submission for the following four (4) years, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for acquisition and/or restoration of ecologically significant areas in Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia ("Land Acquisition and Restoration"). Defendants shall spend no less than a total of $10 million in Project Dollars on Land Acquisition and Restoration over the five year period provided under this Appendix for completion of federally directed Environmental Mitigation Projects.

B. Defendants' proposed plan shall:

1. Describe the proposed Land Acquisition and Restoration projects in sufficient detail to allow the reader to ascertain how each proposed action meets the requirements set out below. For purposes of this Appendix and Section VIII (Environmental Mitigation Projects) of this Consent Decree, land acquisition means purchase of interests in land, including fee ownership, easements, or other restrictions that run with the land that provide for perpetual protection of the acquired land. Restoration may include, by way of illustration, direct reforestation (particularly of tree species that may be affected by acidic deposition) and soil enhancement. Any restoration action must also incorporate the acquisition of an interest in the restored lands sufficient to ensure perpetual protection of the restored land. Any proposal for acquisition of land must identify fully all owners of the interests in the land. Every proposal for acquisition of land must identify the ultimate holder of the interests to be acquired and provide a basis for concluding that the proposed holder of title is appropriate for long-term protection of the ecological or environmental benefits sought to be achieved through the acquisition.

2. Describe generally the ecological significance of the area to be acquired or restored. In particular, identify the environmental/ecological benefits expected as a result of the proposed action. In proposing areas for acquisition and restoration, Defendants shall focus on those areas that are in most need of conservation action or that promise the greatest conservation return on investment.

3. Describe the expected cost of the Land Acquisition and Restoration, including the fair market value of any areas to be acquired.

4. Identify any person or entity other than Defendants that will be involved in the land acquisition or restoration action. Defendants shall describe the third-party's role in the action and the basis for asserting that such entity is able and suited to perform the intended role. For purposes of this Section of the Appendix, third-parties shall only include non-profits; federal, state, and local agencies; or universities. Any proposed third-party must be legally authorized to perform the proposed action or to receive Project Dollars.

5. Include a schedule for completing and funding each portion of the project.

C. Performance - Upon approval of the plan by EPA, after consultation with the Citizen Plaintiffs, Defendants shall complete the Land Acquisition and Restoration project according to the approved plan and schedule.

IV. Nitrogen Impact Mitigation in the Chesapeake Bay

A. Within 120 days of Date of Entry, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for the mitigation of adverse impacts on the Chesapeake Bay associated with nitrogen ("Chesapeake Bay Mitigation Project"). Defendants shall spend no less than a total of $3 million in Project Dollars on the Chesapeake Bay Mitigation Project.

B. Defendant's proposed plan shall:

1. Describe proposed Project(s) that reduce nitrogen loading in the Chesapeake Bay or otherwise mitigate the adverse effects of nitrogen in the Chesapeake Bay. Projects that may be approved include, by way of illustration, creation of forested stream buffers on agricultural land or other land cover to establish a "buffer zone" to keep livestock out of the adjoining waterway and to filter runoff before it enters the waterway.

2. Describe generally the expected environmental benefit of the proposed Chesapeake Bay Mitigation Project. The key criteria for selection of components of the Project are the magnitude of the expected ecological/environmental benefit(s) in relation to the cost and the relative permanence of the expected benefit(s). Expected loadings benefits should be quantified to the extent practicable.

3. Describe the expected cost of each element of the Chesapeake Bay Mitigation Project, including the fair market value of any interests in land to be acquired.

4. Identify any person or entity other than Defendants that will be involved in any aspect of the Chesapeake Bay Mitigation Project. Defendants shall describe the third-party's role in the action and the basis for asserting that such entity is able and suited to perform the intended role. For purposes of this Section of the Appendix, third-parties shall only include non-profits; federal, state, and local agencies; or universities. Any proposed third-party must be legally authorized to perform the proposed action or to receive Project Dollars.

5. Include a schedule for completing and funding each portion of the Project.

C. Performance - Upon approval of the plan for Chesapeake Bay Mitigation by EPA, Defendants shall complete the Project according to the approved plan and schedule.

V. Mobile Source Emission Reduction Projects

A. Within 120 days of the Date of Entry, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for the completion of Projects to reduce emissions from Defendants' fleet of barge tugboats on the Ohio River, diesel trains at or near power plants, Defendants' fleet of motor vehicles in certain eastern states, and/or truck stops in certain eastern states ("Mobile Source Projects"). Defendants shall spend no less than a total of $21 million in Project Dollars on one or more of the three Mobile Source Projects specified in this Section, in accordance with the plans for such Projects approved by EPA, after consultation with the Citizen Plaintiffs. The key criteria for selection of components of the Mobile Source Projects are the magnitude of the expected environmental benefit(s) in relation to the cost.

B. Diesel Tug/Train Project

1. Defendants are among the leading barge operators in the country, with operations on the Ohio River, the Mississippi River, and the Gulf Coast. Barges are propelled by tugboats, which generally use a type of marine diesel fuel known as No. 2 distillate fuel oil. Tugboats that switch to ultra-low sulfur diesel fuel ("ULSD") reduce emissions of NO_X, PM, volatile organic compounds ("VOCs"), and other air pollutants. All marine diesel fuel must be ULSD by June 1, 2012, pursuant to EPA's Nonroad Diesel Rule (see "Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuels; Final Rule," 69 Fed. Reg. 38,958 (June 29, 2004)). Defendants also receive coal by diesel trains.

2. As part of the plan for Mobile Source Projects, Defendants may elect to achieve accelerated emission reductions from their tugboat fleet on the Ohio River ("Ohio River Tug Fleet") and/or their diesel powered trains used at or near their power plants, as one of the three possible mobile source Projects under this Consent Decree ("Diesel Tug/Train Project").

3. The Diesel Tug/Train Project shall require one or more of the following:

   a. The accelerated retrofitting or re-powering of Tugs with engines that require the use of ULSD. Selection of this Project is expressly conditioned upon identification of satisfactory technology and an agreement between EPA and Defendants on how to credit Project Dollars towards this project.

   b. The retrofitting or repowering of the marine engines in the Ohio River Tug Fleet with diesel oxidation catalysts ("DOCs"), diesel particulate filters ("DPFs"), or other equivalent advanced technologies that reduce emissions of PM and VOCs from marine engines in tugboats (collectively "DOC/DPFs"). Defendants shall only install DOCs/DPFs that have received applicable approvals or verifications, if any, from the relevant regulatory agencies for reducing emissions from tugboat engines. Defendants must maintain any DOCs/DPFs installed as part of the Tug Project for the useful life of the equipment (as defined in the proposed Plan), even after the completion of the Tug Project. Project Dollars may be spent on DOCs/DPFs within 5 years of the Date of Entry, in accordance with the approved schedule for the mitigation projects in this Appendix.

c. The accelerated use of ULSD for the Ohio River Tug Fleet, from the Date of Entry through January 1, 2012. Notwithstanding any other provision of this Consent Decree, including this Appendix, Defendants shall only receive credit for the incremental cost of ULSD as compared to the cost of the fuel Defendants would otherwise utilize.

d. Emission reduction measures for diesel powered trains. Such measures may include retro-fitting with, or conversion to, Multiple Diesel Engine GenSets that are EPA Tier III Off-Road certified; Diesel Electric Hybrid; Anti-idling controls/strategies and Auto Shut-Off capabilities. Selection of this Project is expressly conditioned upon identification of satisfactory technology and an agreement between EPA and Defendants on how to credit Project Dollars towards this project.

4. The proposed plan for the Diesel Tug/Train Project shall:

a. Describe the expected cost of the project, including the costs for any equipment, material, labor costs, and the proposed method for accounting for the cost of each element of the Diesel Tug/Train Project, including the incremental cost of ULSD.

b. Describe generally the expected environmental benefit of the project, including any expected fuel efficiency improvements and quantify emission reductions expected.

c. Include a schedule for completing each portion of the Diesel Tug/Train Project.

5. Performance - Upon approval of the Diesel Tug/Train Project plan by EPA, Defendants shall complete the project according to the approved plan and schedule.

C. Hybrid Vehicle Fleet Project

1. AEP has a fleet of approximately 11,000 motor vehicles in the eleven states where it operates, including vehicles in Indiana, Ohio, Michigan, Virginia, West Virginia, and Kentucky. These motor vehicles are generally powered by conventional diesel or gasoline engines and include vehicles such as diesel "bucket" trucks. The use of hybrid engine technologies in Defendants' motor vehicles, such as diesel-electric engines, will improve fuel efficiency and reduce emissions of NO_X, PM, VOCs, and other air pollutants.

2. As part of the plan for Mobile Source Projects, Defendants may elect to spend Project Dollars on the replacement of conventional motor vehicles in their fleet with newly manufactured Hybrid Vehicles ("Hybrid Vehicle Fleet Project").

3. The proposed plan for the Hybrid Vehicle Fleet Project shall:

a. Propose the replacement of conventional gasoline or diesel powered motor vehicles (such as bucket trucks) with Hybrid Vehicles. For purposes of this subsection of this Appendix, "Hybrid Vehicle" means a vehicle that can generate and utilize electric power to reduce the vehicle's consumption of fossil fuel. Any Hybrid Vehicle proposed for inclusion in the Hybrid Fleet Project shall meet all applicable engine standards, certifications, and/or verifications.

b. Provide for Hybrid Vehicles replacement in that portion of Defendants' fleet in Indiana, Ohio, Michigan, West Virginia, Virginia, and/or Kentucky. Notwithstanding any other provision of this Consent Decree, including this Appendix, Defendants shall only receive credit toward Project Dollars for the incremental cost of Hybrid Vehicles as compared to the cost of a newly manufactured, similar motor vehicle.

c. Prioritize the replacement of diesel-powered vehicles in Defendants' fleet.

d. Provide a method to account for the costs of the Hybrid Vehicles, including the incremental costs of such vehicles as compared to conventional gasoline or diesel motor vehicles.

e. Certify that Defendants will use the Hybrid Vehicles for their useful life (as defined in the proposed plan).

f. Include a schedule for completing each portion of the Project.

g. Describe generally the expected environmental benefits of the Project, including any fuel efficiency improvements, and quantify emission reductions expected.

4. Performance - Upon approval by EPA of the plan for the Hybrid Vehicle Fleet Project, after consultation with the Citizen Plaintiffs, Defendants shall complete the Project according to the approved plan.

D. Truck Stop Electrification

1. Long-haul truck drivers typically idle their engines at night at rest areas to supply heat or cooling in their sleeper cab compartments, and to maintain vehicle battery charge while electrical appliances such as televisions, computers, and microwaves are in use. Modifications to rest areas to provide parking spaces with electrical power, heat, and air conditioning will allow truck drivers to turn their engines off. Truck stop electrification reduces idling time and therefore reduces diesel fuel usage, and thus reduces emissions of PM, NO_x, and VOCs.

2. As part of the plan for Mobile Source Projects, Defendants may elect to achieve emission reductions by truck stop electrification, which shall include, where necessary, techniques and infrastructure needed to support such a program ("Truck Stop Electrification Project").

3. The proposed plan for the Truck Stop Electrification Project shall:

a. Identify truck stops in one or more of the following States for Electrification: Ohio, Indiana, Kentucky, North Carolina, Pennsylvania, West Virginia, and Virginia. EPA may give preference to electrification Projects that are co-located, if possible, along the same transportation corridor.

b. Describe the level of expected usage of the planned electrification facilities, air quality in the vicinity of the proposed Projects, proximity of the proposed Project to population centers, and whether the owner or some other entity is willing to pay for some portion of the work.

c. Provide for the construction of truck stop electrification stations with established technologies and equipment.

d. Account for hardware procurement and installation costs at the recipient truck stops.

e. Include a schedule for completing each portion of the Project.

f. Describe generally the expected environmental benefits of the Project and quantify emission reductions expected.

4. Performance - Upon approval of the plan for the Truck Stop Electrification Project by EPA, after consultation with the Citizen Plaintiffs, Defendants shall complete the Project according to the approved plan.

APPENDIX B

REPORTING REQUIREMENTS

I. Annual Reporting Requirements

In accordance with the dates specified below, for periods on and after the Date of Entry, Defendants shall submit annual reports to the United States, the States, and the Citizen Plaintiffs, electronically and in hard copy, as required by Paragraph 143 and certified as required by Paragraph 146. In such annual reports, Defendants shall include the following information:

A. Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x

Beginning on March 31, 2010, for the Eastern System-Wide Annual Tonnage Limitations for NO_x, and March 31, 2011, for the Eastern System-Wide Annual Tonnage Limitations for SO_2, and annually thereafter, Defendants shall report the following information: (a) the total actual annual tons of the pollutant emitted from each Unit (or for Units vented to a common stack, from each combined stack) within the AEP Eastern System, as defined in Paragraph 7, during the prior calendar year; (b) the total actual annual tons of the pollutant emitted from the AEP Eastern System during the prior calendar year; (c) the difference, if any, between the applicable Eastern System-Wide Annual Tonnage Limitation for the pollutant in that calendar year and the amount reported in subparagraph (b); and (d) the annual average emission rate, expressed as a lb/mmBTU for NO_x, for each Unit within the AEP Eastern System and for the entire AEP Eastern System during the prior calendar year. Data reported pursuant to this subsection shall be based upon the CEMS data submitted to the Clean Air Markets Division.

B. Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from all Units at the Clinch River plant on an annual rolling average basis as defined in Paragraphs 47 and 88 for the prior calendar year; and (b) the applicable Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at the Clinch River plant for the prior calendar year. For calendar years other than 2010 and 2015, Defendants shall also report the 12-month rolling average emissions for each month.

C. Plant-Wide Tonnage Limitation for SO_2 at Kammer

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from all Units at the Kammer plant as specified in Paragraph 48 for the prior calendar year; and (b) the Plant-Wide Tonnage Limitation for SO_2 at the Kammer plant for that calendar year.

D. Reporting Requirements for Excess NO_x Allowances

1. Reporting Requirements for Unrestricted Excess NO_x Allowances

Beginning on March 31, 2010, and continuing annually through March 31, 2016, Defendants shall report the number of Unrestricted Excess NO_x Allowances available each year between 2009 through 2015, and how or whether such allowances were used so that Defendants account for each Unrestricted Excess NO_x Allowance for each year during 2009 through 2015. No later than March 31, 2016, Defendants shall report: (a) the cumulative number of unused Unrestricted Excess NO_x Allowances subject to surrender pursuant to Paragraph 75 and calculated pursuant to Paragraph 74, and (b) the total number of unused Unrestricted Excess NO_x Allowances that they surrendered.

2. Reporting Requirements for Restricted Excess NO_x Allowances

a. Beginning on March 31, 2010, and continuing annually through March 31, 2016, Defendants shall report: (a) the number of Restricted Excess NOx Allowances available each year between 2009 through 2015; (b) the actual emissions from any New and Newly Permitted Unit during each year; (c) the actual NOx emissions from the five natural gas plants listed in Paragraph 76 during each year; (d) the amount, if any, of Restricted Excess NOx Allowances that are not subject to surrender each year because of Defendants' investment in renewable energy as defined in Paragraph 77 and the data supporting Defendants' calculation; and (e) the difference between the cumulative total of Restricted Excess NO_x Allowances available from each year and any prior year and the actual emissions reported under (b) and (c), above, for that year and any Restricted Excess NO_x Allowances not subject to surrender reported under (d), above. No later than March 31, 2016, Defendants shall report: (a) the cumulative number of unused Restricted Excess NO_x Allowances subject to surrender calculated pursuant to Paragraphs 76 and 77, and (b) the total number of unused Restricted Excess NO_x Allowances that they surrendered.

b. No later than March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the number of Restricted Excess NO_x Allowances available in the prior year; (b) the actual emissions from any New and Newly Permitted Unit during such year; (c) the actual emissions from the five natural gas plants listed in Paragraph 76 during such year; (d) the amount, if any, of Restricted Excess NO_x Allowances that are not subject to surrender for such year because of Defendants' investment in renewable energy as defined in Paragraph 77 and the data supporting Defendants' calculation; (e) the number of Restricted Excess NO_x Allowances subject to surrender for such year calculated pursuant to Paragraphs 76 and 77; and (f) the total number of unused Restricted Excess NO_x Allowances that they surrendered for such year.

E. Reporting Requirements for Excess SO_2 Allowances

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the number of Excess SO_2 Allowances subject to surrender calculated pursuant to Paragraph 93, and (b) the total number of Excess SO_2 Allowances that they surrendered.

F. Continuous Operation of Pollution Controls required by Paragraphs 68, 69, 87, and 102

On March 31 of the year following Defendants' obligation pursuant to this Consent Decree to commence Continuous Operation of an SCR, FGD, ESP, or Additional NO_x Pollution Controls, Defendants shall report the date that they commenced Continuous Operation of each such pollution control as required by this Consent Decree. Beginning on March 31, 2008, and continuing annually thereafter, Defendants shall report, for any SCR, FGD, ESP, or Additional NO_x Pollution Controls required to Continuously Operate during that year, the duration of any period during which that pollution control did not Continuously Operate, including the specific dates and times that such pollution control did not operate, the reason why Defendants did not Continuously Operate such pollution control, and the measures taken to reduce emissions of the pollutant controlled by such pollution control.

G. Installation of SO_2 and NO_x Pollution Controls

Beginning on March 31, 2008, and continuing annually thereafter, Defendants shall report on the progress of construction of NO_x and SO_2 pollution controls required by this Consent Decree including: (1) if construction is not underway, any available information concerning the construction schedule, including the dates of any major contracts executed during the prior calendar year, and any major components delivered during the prior calendar year; (2) if construction is underway, the estimated percent of installation as of the end of the prior calendar year, the current estimated construction completion date, and a brief description of completion of significant milestones during the prior calendar year, including a narrative description of the current construction status (e.g. foundations completed, absorber installation proceeding all material on-site, new stack erection completed, etc.); and (3) once construction is complete, the dates the equipment was placed in service and any acceptance testing was performed during the prior calendar year.

H. Installation and Operation of PM CEMS

Beginning on March 31, 2013, for Cardinal Units 1 and 2 and a third Unit identified pursuant to Paragraph 110, and continuing annually thereafter for all periods of operation of PM CEMS as required by this Consent Decree, Defendants shall report the data recorded by the PM CEMS, expressed in lb/mmBTU on a 3-hour rolling average basis in electronic format for the prior calendar year, in accordance with Paragraph 107.

I. Other SO_2 Measures

Commencing in the first annual report Defendants submit pursuant to Paragraph 143, and continuing annually thereafter, Defendants shall submit all data necessary to determine Defendants' compliance with the annual average coal content specified in the table in Paragraph 90.

J. 1-Hour Average NO_x Emission Rate and 30-Day Rolling Average Emission Rates for SO_2 and NO_x

1. Beginning on March 31 of the year following Defendants' obligation pursuant to this Consent Decree to first comply with an applicable 1-Hour Average NO_x Emission Rate and/or 30-Day Rolling Average Emission Rate for SO_2 and NO_x, and continuing annually thereafter, Defendants shall report all 1-Hour Average Emission Rate results and/or 30-Day Rolling Average Emission Rate results to determine compliance with such emission rate, as defined in Paragraph 4 or 5, as appropriate. Defendants shall also report: (a) the date and time that the Unit initially combusts any fuel after shutdown; (b) the date and time after startup that the Unit is synchronized with a utility electric distribution system; (c) the date and time that the fire is extinguished in a Unit; and (d) for the fifth and subsequent Cold Start Up Period that occurs within any 30-Day period, the earlier of the date and time that is either (i) eight hours after the unit is synchronized with a utility electric distribution system, or (ii) the flue gas has reached the SCR operational temperature range specified by the catalyst manufacturer.

2. Within the first report that identifies a 1-Hour Average NO_x Emission Rate or 30-Day Rolling Average Emission Rate for SO_2 or NO_x, Defendants shall include at least five (5) example calculations (including hourly CEMS data in electronic format for the calculation) used to determine the 1-Hour Average NO_x Emission Rate and the 30-Day Rolling Average Emission Rate for SO_2 or NO_x for five (5) randomly selected days. If at any time Defendants change the methodology used in determining the 1-Hour Average NO_x Emission Rate or the 30-Day Rolling Average Emission Rate for SO_2 or NO_x, Defendants shall explain the change and the reason for using the new methodology.

K. 30-Day Rolling Average Removal Efficiency for SO_2

1. Beginning on March 31 of the year following Defendants' obligation pursuant to this Consent Decree to first comply with a 30-Day Rolling Average Removal Efficiency, and continuing annually thereafter, Defendants shall report all 30-Day Rolling Average Removal Efficiency results to determine compliance with such removal efficiency as defined in Paragraph 6 or, for Conesville Units 5 and 6, as specified in Appendix C.

2. Within the first report that identifies a 30-Day Rolling Average Removal Efficiency for SO_2, Defendants shall include at least five (5) example calculations (including hourly CEMS data in electronic format for the calculation) used to determine the 30-Day Rolling Average Removal Efficiency for five (5) randomly selected days. If

at any time Defendants change the methodology used in determining the 30-Day Rolling Average Removal Efficiency, Defendants shall explain the change and the reason for using the new methodology.

L. PM Emission Rates

Beginning on March 31, 2010, for Cardinal Units 1 and 2, and beginning on March 31, 2013 for Muskingum River Unit 5, and continuing annually thereafter, Defendants shall report the PM Emission Rate as defined in Paragraph 51, for Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. For all such Units, Defendants shall attach a copy of the executive summary and results of any stack test performed during the calendar year covered by the annual report.

M. Environmental Mitigation Projects

1. Mitigation Projects to be Conducted by the States

Defendants shall report the disbursement of funds as required in Paragraph 127 of the Consent Decree in the next annual progress report that Defendants submit pursuant to Paragraph 143 following such disbursement of funds.

2. Appendix A Projects

Beginning March 31, 2008, and continuing on March 31 of each year thereafter until completion of each Project (including any applicable periods of demonstration or testing), Defendants shall provide the United States and Citizen Plaintiffs with written reports detailing the progress of each Project, including Project Dollars.

N. Other Unit becoming an Improved Unit

If Defendants decide to make an Other Unit an Improved Unit, Defendants shall so state in the next annual progress report they submit pursuant to Paragraph 143 after making such decision, and comply with the reporting requirements specified in Section I.G of this Appendix and any other reporting or notice requirements in accordance with the Consent Decree.

II. Deviation Reports

Beginning March 31, 2008, and continuing annually thereafter, Defendants shall report a summary of all deviations from the requirements of the Consent Decree that occurred during the prior calendar year, identifying the date and time that the deviation occurred, the date and time the deviation was corrected, the cause and any corrective actions taken for each deviation, if necessary, and the date that the deviation was initially reported under Paragraph 145. In addition to any express requirements in Section I, above, or in the Consent Decree, such deviations required to be reported include, but are not limited to, the following requirements: the 1-Hour Average NO_x Emission Rate, the

30-Day Rolling Average Emission Rates for SO_2 and NO_x, the 30-Day Rolling Average Removal Efficiency for SO_2, and the PM Emission Rate.

III. Submissions Pending Review

In each annual report Defendants submit pursuant to Paragraph 143, Defendants shall include a list of all plans or submissions made pursuant to this Consent Decree during the calendar year covered by the annual report, the date(s) such plans or submissions were submitted to one or more Plaintiffs for review and/or approval, and shall identify which, if any, are still pending review and approval by Plaintiffs upon the date of submission of the annual report.

IV. Other Information Necessary To Determine Compliance

To the extent that information not expressly identified above is necessary to determine Defendants' compliance with the requirements of this Consent Decree during a reporting period, and has not otherwise been submitted in accordance with the provisions of the Consent Decree, Defendants shall provide such information as part of the annual report required pursuant to Section XI of the Consent Decree.

APPENDIX C

MONITORING STRATEGY AND CALCULATION OF THE 30-DAY ROLLING AVERAGE REMOVAL EFFICIENCY FOR CONESVILLE UNITS 5 AND 6

I. Monitoring Strategy

1. The SO_2 monitoring system for Conesville Units 5 & 6 will consist of two separate FGD inlet monitors in each of the two FGD inlet ducts for each Unit, and one FGD outlet monitor in the combined flow from the outlets of the FGD modules for each Unit, prior to the common stack.

2. Due to space constraints and potential interferences, monitors are currently located in the inlet duct for one FGD module on each Unit and at the combined outlet from both FGD modules for each Unit prior to entering the stack using best engineering judgment.

3. On or before December 31, 2008, Defendants shall submit a monitoring plan to EPA for approval that will propose where to site and install an additional inlet monitor in each of the unmonitored FGD inlet ducts for each Unit, and include a requirement that Defendants submit a complete certification application for the Conesville Units 5 & 6 monitoring system to EPA and the state permitting authority.

4. The Monitoring Plan will incorporate the applicable procedures and quality assurance testing found in 40 C.F.R. Part 75, subject to the following:

   a. The PS-2 siting criteria will not be applied to these monitoring systems; however, the majority of the procedures in Section 8.1.3.2 of PS-2 will be followed. Sampling of at least nine (9) sampling points selected in accordance with PS-1 will be performed prior to the initial RATA. If the resultant SO_2 emission rates for any single sampling point calculated in accordance with Equation 19.7 are all within 10% or 0.02 lb/mmBtu of the mean of all nine (9) sampling points, the alternative traverse point locations (0.4, 1.2, and 2.0 meters from the duct wall) will be representative and may be used for all subsequent RATAs.

   b. The required relative accuracy test audit will be performed in accordance with the procedures of 40 C.F.R. Part 75, except that the calculations will be performed on an SO_2 emission rate basis (i.e., lb/mmBtu).

   c. The criteria for passing the relative accuracy test audit will be the same criteria that 40 C.F.R. Part 75 requires for relative accuracy or alternative performance specification as provided for NO_x emission rates.

d. "Diluent capping" (i.e., 5% CO_2) will be applied to the SO_2 emission rate for any hours where the measured CO_2 concentration rounds to zero.

e. Results of quality assurance testing, data gathered by the inlet and outlet monitoring systems, and the resultant 30-day Rolling Average Removal Efficiencies for these monitoring systems are not required to be reported in the quarterly reports submitted to EPA's Clean Air Markets Division for purposes of 40 C.F.R. Part 75. Results will be maintained at the facility and available for inspection, and the 30-day Rolling Average Removal Efficiency will be reported in accordance with the requirements of the Consent Decree and Appendix B. Equivalent data retention and reporting requirements will be incorporated into the applicable permits for these Units.

f. Missing Data Substitution of 40 C.F.R Part 75 will not be implemented.

g. Initial performance testing will be performed before the effective date of the 30-Day Rolling Average Removal Efficiency requirements, and the results will be reported to Plaintiffs as part of the annual report submitted in accordance with Appendix B.

II. Calculation of 30-Day Rolling Average Removal Efficiency

1. Removal efficiency shall be calculated by the equation:

$$[SO_2 \text{ emission rate}_{\text{Inlet}} - SO_2 \text{ emission rate}_{\text{Outlet}}] / SO_2 \text{ emission rate}_{\text{Inlet}} * 100$$

2. Inlet and outlet emission rates shall be calculated using the methodology specified in 40 C.F.R. Part 60 Appendix B – Method 19. Inlet emission rates will be based on the average of the valid recorded values calculated for each of the inlet FGD monitors at each Unit. Measurements are made on a wet basis, so Equation 19.7 will be utilized to determine the hourly SO_2 emission rate at each location. To make the conversion between the measured wet SO_2 and CO_2 concentrations and an emission rate in pounds per million BTU, an electronic Data System will perform Equation 19.7 using the SO_2 ppm conversion factor from Table 19-1 of Method 19 and the Fc factor for the applicable fuel (currently bituminous coal) in Table 19-2 of Method 19. The resulting equation will be:

$$\text{Emission rate (lb } SO_2/\text{mmBtu)} = 1.660 \times 10^{-7} * SO_2 \text{ (in ppm)} * Fc * 100 / CO_2 \text{ (in \%)}$$

3. The electronic data system will calculate the hourly average SO_2 and CO_2 concentration in accordance with 40 C.F.R. Part 75 quality control/quality assurance requirements and will compute and retain these SO_2 emission rates for every operating hour meeting the minimum data capture requirements in accordance with 40 C.F.R. Part 75. Prior to the

calculation of the SO_2 emission rate, hourly SO_2 and CO_2 concentrations will be rounded to the nearest tenth (i.e., 0.1 ppm or 0.1 % CO_2) and the resulting SO_2 emission rate will be rounded to the nearest thousandth (i.e., 0.001 lb/mmBtu).

4. From these hourly SO_2 emission rates, SO_2 removal efficiencies will be calculated for each hour when the Unit is firing fossil fuel, and the hourly SO_2 and CO_2 monitors meet the QA/QC requirements of Part 75. Hourly SO_2 removal efficiencies will be computed by taking the hourly inlet SO_2 emission rate minus the outlet SO_2 emission rate, dividing the result by inlet SO_2 emission rate and multiplying by 100. The resulting removal efficiency will be rounded to the nearest tenth (i.e., 95.1%). Daily SO_2 removal efficiencies will be calculated by taking the sum of Hourly SO_2 removal efficiencies and dividing by the number of valid monitored hours for each Operating Day. The resulting daily removal efficiencies will be rounded to the nearest tenth (i.e., 95.1%).

5. The 30-Day Rolling Average Removal Efficiency will be computed by taking the current Operating Day's daily SO_2 removal efficiency (as described in Paragraph 4 of this Appendix C) plus the previous 29 Operating Days' daily SO_2 removal efficiency, and dividing the sum by 30. In the event that a daily SO_2 removal efficiency is not available for an Operating Day, Defendants shall exclude that Operating Day from the calculation of the 30-Day Rolling Average Removal Efficiency. The resulting 30-day Rolling Average Removal Efficiency will be rounded to the nearest tenth of a percent (i.e., a value of 95.04% rounds down to 95.0%, and a value of 95.05% rounds up to 95.1%).

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King Civil Action No. C2-05-360 Civil Action No. C2-04-1098

ORDER ENTERING THIRD JOINT MODIFICATION TO CONSENT DECREE

This matter is before the Court on Plaintiff the United States of America's Motion to Approve the Third Joint Modification of the Consent Decree. (Doc. No. 547.) For the reasons set forth within Plaintiff's motion, the Court **GRANTS** the motion and **ENTERS** the Third Joint Modification to Consent Decree, which is attached hereto.

This Order renders moot Defendants' Application for Judicial Interpretation of the Consent Decree (Doc. No. 528) and Defendants' Motion to Strike (Doc. No. 539). These two motions are therefore **DENIED AS MOOT**.

IT IS SO ORDERED this 14th day of MAY, 2013.

EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA, Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King

THIRD JOINT MODIFICATION TO CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS pursuant to Paragraph 87 of the Consent Decree, as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree, filed on April 5, 2010 (Case No. 99-1250, Docket # 371), and as modified by a second Joint Modification to Consent Decree With Order Modifying Consent Decree, filed on December 28, 2010 (Case No. 99-1250, Docket # 372), the Defendants are required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization System (FGD) no later than December 31, 2015 on Big Sandy Unit 2, December 31, 2015 on Muskingum River Unit 5, December 31, 2017 on Rockport Unit 1, and December 31, 2019 on Rockport Unit 2.

WHEREAS, on October 31, 2012, the Defendants filed an Application for Judicial Interpretation of Consent Decree in Case No. 99-1182 (Docket # 528) and the related cases.

WHEREAS, the United States, the States and Citizen Plaintiffs filed a Memorandum in Opposition (Case No. 99-1182, Docket # 534), and Citizen Plaintiffs filed a Supplemental Memorandum in Opposition (Case No. 99-1250, Docket # 381) to the Defendants' Application.

WHEREAS all Parties made additional filings and the Application was scheduled for a hearing on December 17, 2012.

WHEREAS, the Parties have engaged in settlement discussions and have reached agreement on a modification to the Consent Decree as set forth herein.

WHEREAS, the Parties have agreed, and this Court by entering this Third Joint Modification finds, that this Third Joint Modification has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Clean Air Act, 42 U.S.C. §7401, *et seq*.; and that entry of this Third Joint Modification without further litigation is the most appropriate means of resolving this matter.

WHEREAS, the Parties agree and acknowledge that final approval of the United States and entry of this Third Joint Modification is subject to the procedures set forth in 28 CFR § 50.7, which provides for notice of this Third Joint Modification in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Third Joint Modification is inappropriate, improper, or inadequate. No Party will oppose entry of this Third Joint Modification by this Court or challenge any provision of this Third Joint Modification unless the United States has notified the Parties, in writing, that the United States no longer supports entry of the Third Joint Modification.

NOW THEREFORE, for good cause shown, without admission of any issue of fact or law raised in the Application or the underlying litigation, the Parties hereby seek to modify the Consent Decree in this matter, and upon the filing of a Motion to Enter by the United States, move that the Court sign and enter the following Order:

1. Add a definition of "Cease Burning Coal" as new Paragraph 8A of the Consent Decree as follows:

<u>8A. "Cease Burning Coal" means that Defendants shall permanently cease burning coal for purposes of generating electricity from a Unit, and shall submit all necessary notifications or</u>

requests for permit amendments to reflect the permanent cessation of coal firing at the Unit.

2. Modify the definition of "Continuously Operate" in Paragraph 14 of the Consent Decree as follows:

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, DSI, ESP, or Other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

3. Add a new definition of "Dry Sorbent Injection" or "DSI" as new Paragraph18A of the Consent Decree as follows:

18A. "Dry Sorbent Injection" or "DSI" means a pollution control system in which a sorbent is injected into the flue gas path prior to the particulate pollution control device for the purpose of reducing SO_2 emissions. For purposes of the DSI systems required to be installed at the Rockport Units only, the DSI systems shall utilize a sodium based sorbent and be designed to inject at least 10 tons per hour of a sodium based sorbent. Defendants may utilize a different sorbent at the Rockport Units provided they obtain prior approval from Plaintiffs pursuant to Paragraph 148 of the Consent Decree.

4. Modify the definition of "Improved Unit" in Paragraph 28 of the Consent Decree as follows:

28. An "Improved Unit" for SO_2 means an AEP Eastern System Unit equipped with an FGD or scheduled under this Consent Decree to be equipped with an FGD, or required to be Retired, Retrofitted, Re-Powered, or Refueled.

The remainder of Paragraph 28 shall remain the same.

5. Add a definition of "Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport" as new Paragraph 48A of the Consent Decree, as follows:

48A. "Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport" means the sum of the tons of SO_2 emitted during all periods of operation from the Rockport Plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, during the relevant calendar year (*i.e.*, January 1 – December 31).

6. Add a definition of "Refuel" as new Paragraph 53A of the Consent Decree, as follows:

53A. "Refuel" means, solely for purposes of this Consent Decree, the modification of a unit as necessary such that the modified unit generates electricity solely through the combustion of natural gas rather than coal, including the installation and Continuous Operation of the NO_x controls required by Section IV of this Consent Decree. Nothing herein shall prevent the reuse of any equipment at any existing unit or new emissions unit, provided that AEP applies for, and obtains, all required permits, including, if applicable, a PSD or Nonattainment NSR permit.

7. Modify the definition of "Retrofit" in Paragraph 56 of the Consent Decree as follows:

56. "Retrofit" means that the Unit must install and Continuously Operate both an SCR and an FGD, as defined in the Consent Decree. For purposes of the requirements in Paragraph 87 for the Rockport Units, "Retrofit" also means that the Unit will be equipped with a post-combustion wet- or dry-FGD system with a control technology vendor guaranteed design removal efficiency of 98% or more, and subject upon installation to a 30-Day Rolling Average Emissions Rate of 0.100 lb/mmBTU for SO_2, if the Unit burns coal with an uncontrolled SO_2 emissions rate of 3.0 lb/mmBTU or higher, or a 30-day Rolling Average Emission Rate of 0.060 lb/mmBTU if the

Unit burns coal with an uncontrolled SO_2 emissions rate below 3.0 lb/mmBTU. For the 600 MW listed in the table in Paragraph 68 and 87, "Retrofit" means that the Unit must meet a federally-enforceable 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for NOx and a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for SO2, measured in accordance with the requirements of this Consent Decree.

8. Modify the Eastern System-Wide Annual Tonnage Limitations for SO_2 in the table in Paragraph 86 of the Consent Decree as follows:

86. Notwithstanding any other provision of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year(s)	**Eastern System-Wide Annual Tonnage Limitations for SO_2**	**Modified Eastern System-Wide Annual Tonnage Limitations for SO_2**
2016	~~260,000 tons~~	145,000 tons
2017	~~235,000 tons~~	145,000 tons
2018	~~184,000 tons~~	145,000 tons
2019~~, and each year thereafter~~ - 2021	~~174,000 tons~~	113,000 tons per year
2022 - 2025	~~174,000 tons~~	110,000 tons per year
2026 - 2028	~~174,000 tons~~	102,000 tons per year
2029, and each year thereafter	~~174,000 tons~~	94,000 tons per year

The remainder of the table in Paragraph 86 shall remain the same.

9. Modify the SO_2 pollution control requirements and compliance dates listed in the

table in Paragraph 87 of the Consent Decree for Big Sandy Unit 2, Muskingum River Unit 5, Rockport Units 1 and 2, and Tanners Creek Unit 4 as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, ~~or~~ Re-power, or Refuel such Unit:

Unit	SO_2 Pollution Control	Modified SO_2 Pollution Control	Date	Modified Date
Big Sandy Unit 2	~~FGD~~	Retrofit, Retire, Re-power, or Refuel	December 31, 2015	NA
Muskingum River Unit 5	~~FGD~~	Cease Burning Coal and Retire Or Cease Burning Coal and Refuel	~~December 31, 2015~~	December 15, 2015 December 31, 2015, unless the Refueling project is not completed in which case the unit will be taken out of service no later than December 31, 2015 and will not restart until the Refueling project is completed. The Refueling project must be completed by June 30, 2017.
First Rockport Unit	~~FGD~~	Dry Sorbent Injection, and Retrofit, Retire, Re-power, or Refuel	~~December 31, 2017~~	April 16, 2015 December 31, 2025.
Second Rockport Unit	~~FGD~~	Dry Sorbent Injection, and	~~December 31, 2019~~	April 16, 2015 and

Unit	SO_2 Pollution Control	Modified SO_2 Pollution Control	Date	Modified Date
		Retrofit, Retire, Re-power, or Refuel		December 31, 2028.
Tanners Creek Unit 4	NA	Retire or Refuel	NA	June 1, 2015

The remainder of the table in Paragraph 87 of the Consent Decree shall remain the same, including the Joint Modifications previously made to the compliance deadlines for Amos Units 1 and 2.

10. Add a new Paragraph 89A establishing the Plant-Wide Annual Tonnage Limitations for SO_2 at Rockport, as follows:

89A. For each of the calendar years set forth in the table below, Defendants shall limit their total annual SO_2 emissions from Rockport Units 1 and 2 to Plant-Wide Annual Tonnage Limitations for SO_2 as follows:

Calendar Years	Plant-Wide Annual Tonnage Limitations for SO_2
2016 - 2017	28,000 tons per year
2018 - 2019	26,000 tons per year
2020 - 2025	22,000 tons per year
2026 - 2028	18,000 tons per year
2029, and each year thereafter	10,000 tons per year

11. Modify Paragraph 92 of the Consent Decree as follows:

92. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use any SO_2 Allowances to comply with any requirements of this

Consent Decree, including by claiming compliance with any emission limitation, Eastern System-Wide Annual Tonnage Limitation, Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, or Plant-Wide Annual Tonnage Limitations for SO_2 at Rockport required by this Consent Decree by using, tendering, or otherwise applying SO_2 Allowances to achieve compliance or offset any emission above the limits specified in this Consent Decree.

12. Modify Paragraph 100 of the Consent Decree as follows:

100. To the extent an Emission Rate, 30-Day Rolling Average Removal Efficiency, Eastern System-Wide Annual Tonnage Limitation, or Plant-Wide Annual Tonnage Limitation for SO_2 is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine the Emission Rate or annual emissions.

13. Modify Paragraph 104 of the Consent Decree as follows:

104. On or before the date established by this Consent Decree for Defendants to achieve and maintain 0.030 lb/mmBTU at Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5, Defendants shall conduct a performance test for PM that demonstrates compliance with the PM Emission Rate required by this Consent Decree. Within forty-five (45) days of each such performance test, Defendants shall submit the results of the performance test to Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree. On and after the date that Muskingum River Unit 5 complies with the requirement to Cease Burning Coal pursuant to Paragraph 87 of this Consent Decree, Defendants shall no longer be obligated to comply with the performance testing requirements for Muskingum River Unit 5 contained in this Paragraph.

14. Modify Paragraph 105 of the Consent Decree as follows:

105. Beginning in calendar year 2010 for Cardinal Unit 1 and Cardinal Unit 2, and calendar year 2013 for Muskingum River Unit 5, and continuing in each calendar year thereafter, Defendants shall conduct a stack test for PM on each stack servicing Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. The annual stack test requirement imposed by this Paragraph may be satisfied by stack tests conducted by Defendants as required by their permits from the State of Ohio for any year that such stack tests are required under the permits. On and after the date that Muskingum River Unit 5 complies with the requirement to Cease Burning Coal pursuant to Paragraph 87 of this Consent Decree, Defendants shall no longer be obligated to comply with the stack testing requirements for Muskingum River Unit 5 contained in this Paragraph.

15. Modify Paragraph 119 of the Consent Decree as follows:

119. Defendants shall implement the Environmental Mitigation Projects described in Appendix A to this Consent Decree, shall fund the categories of Projects described in Subsection B, below, and shall implement the Citizen Plaintiffs' Renewable Energy Project and Citizen Plaintiffs' Mitigation Projects described in Subsection C, below, (collectively, the "Projects") in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree.

The remainder of Paragraph 119 shall remain the same.

16. Add a new Subsection C after Paragraph 128 of the Consent Decree as follows:

C. Citizen Plaintiffs' Renewable Energy Project and Citizen Plaintiffs' Mitigation Projects.

128A. Citizen Plaintiffs' Renewable Energy Project. Defendants shall implement a renewable energy project as described below during the period from 2013 through 2019.

a. If, during the period from 2013-2015, a renewable energy production tax credit of at least 2.2 cents/kwh for ten years is available for new wind electricity production facilities upon which construction is commenced within one year or more after enactment of the tax credit (or an alternative tax benefit is available that provides sufficient economic value so that the levelized cost to customers does not exceed the weighted average cost of any existing contracts with Indiana Michigan Power Company ("I&M") for 50 MW or greater of wind capacity, adjusted for inflation) I&M will secure 200 MW of new wind energy capacity from facilities located in Indiana or Michigan that qualify for the production tax credit or alternative tax benefit within two years after enactment. For the avoidance of doubt, so long as the energy production tax credit contained in the American Taxpayer Relief Act of 2012 allows projects that have commenced construction by December 31, 2013, and that are placed in service by December 31, 2014, to qualify for the energy production tax credit provided in that Act, then I&M shall be obligated to secure new renewable energy purchase agreements for 200 MW of new wind energy capacity.

b. If a renewable energy production tax credit or alternative tax benefit as described in subparagraph a., above, is not available during 2013-2015, but becomes available during 2016-2019 for new wind electricity production facilities on which construction is commenced within one year or more after the production tax credit or alternative tax benefit is enacted, I&M will use commercially reasonable efforts to secure 200 MW of new wind energy capacity from facilities located in Indiana or Michigan that qualify for the production tax credit or alternative tax benefit within two years after enactment.

c. If a renewable energy production tax credit or alternative tax benefit as described in subparagraph a., above, is not available during the period from 2013 – 2019 for new wind electricity production facilities on which construction is commenced within one year or more after the production tax credit or alternative tax benefit is enacted, I&M shall be relieved of its obligations to secure new wind energy capacity under this Paragraph 119A.

128B. Citizen Plaintiffs' Mitigation Projects. I&M will provide $2.5 million in mitigation funding as directed by the Citizen Plaintiffs for projects in Indiana that include diesel retrofits, health and safety home repairs, solar water heaters, outdoor wood boilers, land acquisition projects, and small renewable energy projects (less than 0.5 MW) located on customer premises that are eligible for net metering or similar interconnection arrangements on or before December 31, 2014. I&M shall make payments to fund such Projects within seventy-five (75) days after being notified by the Citizen Plaintiffs in writing of the nature of the Project, the amount of funding requested, the identity and mailing address of the recipient of the funds, payment instructions, including taxpayer identification numbers and routing instructions for electronic payments, and any other information necessary to process the requested payments. Defendants shall not have approval rights for the Projects or the amount of funding requested, but in no event shall the cumulative amount of funding provided pursuant to this Paragraph 128B exceed $2.5 million.

17. Modify Paragraph 127 of the Consent Decree as follows:

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008, and for an additional

amount not to exceed $6.0 million in 2013. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified by the States in writing. Notwithstanding the maximum annual funding limitations above, if the total costs of the projects submitted in any one or more years is less than the maximum annual amount, the difference between the amount requested and the maximum annual amount for that year will be available for funding by the Defendants of new and previously submitted projects in the following years, except that all amounts not requested by and paid to the States within eleven (11) years after the Date of Entry of this Consent Decree shall expire.

18. Modify Paragraph 133 of the Consent Decree as follows:

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree shall resolve all civil claims of the United States against Defendants that arise based on a modification commenced before December 31, 2018, or, solely for the first Rockport Unit, before December 31, 2025, or, solely for the second Rockport Unit, before December 31, 2028, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of this Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

The remainder of Paragraph 133 shall remain the same.

19. Modify the table in Paragraph 150 of the Consent Decree as follows:

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
x. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
y. Failure to fund a Citizen Plaintiffs' Mitigation Project as required by Paragraph 119B of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
z. Failure to implement the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 128A of this Consent Decree	$10,000 per day per violation during the first 30 days, $32,500 per day per violation thereafter

The remainder of the table in Paragraph 150 shall remain the same.

20. In addition to the requirements reflected in Appendix B (Reporting Requirements) to the Consent Decree, Defendants shall include in their Annual Report to Plaintiffs the following information:

O. Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport

Beginning on March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from Units 1 and 2 at the Rockport Plant for the prior calendar year; (b) the Plant-Wide Annual Tonnage Limitation for SO_2 at the Rockport Plant for the prior calendar year as set forth in Paragraph 89A of the Consent Decree; and (c) for the annual reports for calendar years 2015 – 2028, Defendants shall report the daily average SO_2 emissions from the Rockport Plant expressed in lb/mmBTU, and the daily sorbent deliveries to the Rockport Plant by weight.

P. Citizen Plaintiffs' Renewable Energy Project

Beginning on March 31, 2014, and continuing each year thereafter until completion of the Citizen Plaintiffs' Renewable Energy Project, Defendants shall include a written report detailing the progress of the implementation of the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 119A of the Consent Decree.

Q. Citizen Plaintiffs' Mitigation Projects

Beginning on March 31, 2013, and continuing each year until March 31, 2015, Defendants shall include a written report detailing the progress of implementation of the Citizen

Plaintiffs' Mitigation Projects required by Paragraph 119B of the Consent Decree.

R. By March 31, 2015, Defendants shall notify Plaintiffs of their intent to Retire or Refuel Muskingum River 5.

S. By March 31, 2024, Defendants shall notify Plaintiffs of their decision to Retrofit, Retire, Re-Power or Refuel the first Rockport Unit. If Defendants elect to Retrofit the Unit, Defendants shall provide with such notification, information regarding the removal efficiency guarantee requested from and obtained from the control technology vendor and the sulfur content of the fuel used to design the FGD, including any non-confidential information regarding the SO_2 control technology filed by Defendants with the public utility regulator.

T. By March 31, 2027, Defendants shall notify Plaintiffs of their decision to Retrofit, Retire, Re-power or Refuel the second Rockport Unit. If Defendants elect to Retrofit the Unit, Defendants shall provide with such notification, information regarding the removal efficiency guarantee requested from and obtained from the control technology vendor and the sulfur content of the fuel used to design the FGD, including any non-confidential information regarding the SO_2 control technology filed by Defendants with the public utility regulator.

U. If Defendants elect to Retrofit one or both of the Rockport Units, beginning in the annual reports submitted for calendar years 2026 and/or 2029, as applicable, Defendants shall report a 30-Day Rolling Average SO_2 Emission Rate for the Unit(s) that is (are) Retrofit in accordance with Paragraph 5 of the Consent Decree. In addition, Defendants shall report a 30-Day Rolling Average Uncontrolled Emission Rate for SO_2 for the Unit(s) that is(are) Retrofit based on daily as burned coal sampling and analysis or an inlet SO_2 CEMs upstream of the FGD.

The remainder of Appendix B shall remain the same.

21. Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS 14th DAY OF May, 2013.

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

Respectfully submitted,

FOR THE UNITED STATES OF AMERICA:

Ignacia S. Moreno

IGNACIA S. MORENO
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

Myles E. Flint by BAW w/ permission

MYLES E. FLINT, II
Senior Counsel
Environmental Enforcement Section
Environmental and Natural Resources Division
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20530
(202) 307-1859

FOR THE UNITED STATES OF AMERICA:

SUSAN SHINKMAN
Director
Office of Civil Enforcement
United States Environmental Protection Agency

PHILLIP A. BROOKS
Director, Air Enforcement Division
Office of Civil Enforcement
United States Environmental Protection Agency

SEEMA KAKADE
Attorney-Advisor
Air Enforcement Division
Office of Civil Enforcement
United States Environmental Protection Agency

FOR THE COMMONWEALTH OF MASSACHUSETTS:

MARTHA COAKLEY
Attorney General

By: ______________________
FREDERICK D. AUGENSTERN
Assistant Attorney General
Environmental Protection Division
1 Ashburton Place, 18th Floor
Boston, Massachusetts 02108

FOR THE STATE OF CONNECTICUT:

GEORGE JEPSEN
Attorney General

By: ______________________
KIMBERLY MASSICOTE
Assistant Attorney General
Office of the Attorney General
55 Elm Street, P.O. Box 120
Hartford, Connecticut 06141-0120

FOR THE STATE OF MARYLAND:

DOUGLAS F. GANSLER
Attorney General

By: Matthew Zimmerman
MATTHEW ZIMMERMAN
Assistant Attorney General
Office of the Attorney General
1800 Washington Blvd.
Baltimore, Maryland 21230

FOR THE STATE OF NEW HAMPSHIRE:

MICHAEL A. DELANEY
Attorney General

By:______________________
K. ALLEN BROOKS
Senior Assistant Attorney General
33 Capitol Street
Concord, New Hampshire 03301

FOR THE STATE OF NEW JERSEY:

JEFFREY S. CHIESA
Attorney General

By: Jon C. Martin

JON C. MARTIN
Deputy Attorney General
New Jersey Dept. of Law & Public Safety
25 Market St., P.O. Box 093
Trenton, NJ 08625-0093

FOR THE STATE OF NEW YORK:

ERIC T. SCHNEIDERMAN
Attorney General

By: ______________________
MICHAEL J. MYERS
Assistant Attorney General
Environmental Protection Bureau
The Capitol
Albany, New York 12224

FOR THE STATE OF RHODE ISLAND:

PETER F. KILMARTIN
Attorney General

By: ____________________
GREGORY S. SCHULTZ
Special Assistant Attorney General
150 South Main Street
Providence, Rhode Island 02903

FOR THE STATE OF VERMONT:

WILLIAM H. SORRELL
Attorney General

By: ______________________
THEA SCHWARTZ
Assistant Attorney General
Environmental Division
109 State Street
Montpelier, Vermont 05609-1001

FOR NATURAL RESOURCES DEFENSE COUNCIL, INC.:

Nancy S Marks

NANCY S. MARKS
Natural Resources Defense Council, Inc.
40 West 20th Street
New York, NY 10011

FOR SIERRA CLUB:

SHANNON FISK
Earthjustice
1617 John F. Kennedy Blvd., Suite 1675
Philadelphia, PA 19103

FOR OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA[1], NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION AND LEAGUE OF OHIO SPORTSMEN:

Faith E. Bugel

FAITH BUGEL
Environmental Law and Policy Center
35 East Wacker Drive, Suite 1300
Chicago, Illinois 60601-2110

---

[1] Environment America is the same entity that signed on to the original Consent Decree as United States Public Interest Research Group.

LOCAL COUNSEL FOR SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, INC., OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA[1]. NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION AND LEAGUE OF OHIO SPORTSMEN:

PETER PRECARIO 0027080
Attorney At Law
2 Miranova Pl., Suite 500
Columbus, Ohio 43215-4525

[1] Environment America is the same entity that signed on to the original Consent Decree as United States Public Interest Research Group.

FOR DEFENDANTS AMERICAN ELECTRIC POWER SERVICE CORPORATION, ET AL.:

David Feinberg

DAVID M. FEINBERG
General Counsel
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	**)**	
A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	
Environmental Compliance Plan; (3) An Order	**)**	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

EVERETT G. PHILLIPS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned Everett G. Phillips, being duly sworn, deposes and says he is the Managing Director, Distribution Region Operations for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Everett G. Phillips

Everett G Phillips

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2014-00396
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Everett G. Phillips, this the 22 day of December, 2014.

Notary Public

My Commission Expires: 4/5/2015

DIRECT TESTIMONY
OF
EVERETT G. PHILLIPS
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2014-00396

TABLE OF CONTENTS

EXHIBITS

DIRECT TESTIMONY
OF
EVERETT G. PHILLIPS
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2014-00396

I. INTRODUCTION

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

A. My name is Everett G. Phillips. My business address is 12333 Kevin Avenue, Ashland, Kentucky 41102. I am the Managing Director of Distribution Region Operations for the Kentucky Power Company (KPCo or Company). Kentucky Power Company is a subsidiary of American Electric Power Company (AEP).

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

A. I earned a bachelor's degree in Electrical Engineering in 1985 from West Virginia University. I am a registered professional engineer in the Commonwealth of Kentucky. I am a member of the National Society of Professional Engineers (NSPE). I am an advisory board member of the Power and Energy Institute of Kentucky (PEIK) for University of Kentucky and a member of the applied process technologies advisory committee for the Ashland Community and Technical College. Throughout my career, I have held positions of increasing responsibility. In 1998, I was promoted to the KPCo Pikeville district superintendent position, and in 2000, I became the Pikeville district manager. In 2004, I moved to Ashland, Kentucky where I was Director of Customer and Distribution Operations. In 2011, I assumed my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF DISTRIBUTION REGION OPERATIONS?

A. I am responsible for overseeing the planning, construction, operation and maintenance of KPCo's distribution system. My duties include the oversight and management of service extension to new customers, the safe and reliable delivery of service to our customers and the restoration of service when outages occur. My responsibilities also include overseeing KPCo's Distribution Vegetation Management Program.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified before this Commission and filed testimony in the Company's base rate case filing, Case No. 2009-00459.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of KPCo's current power quality and service reliability programs. I will discuss the yearly Distribution Operation and Maintenance (O&M) expenses and capital spending since the last base case (Case No. 2009-00459). Finally, I will discuss the Company's progress in the implementation of the Distribution Vegetation Management Plan (Plan), and the changes to the Plan being proposed by the Company.

Q. **ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR TESTIMONY?**

A. Yes. I am sponsoring the following exhibits attached to my testimony:

Exhibit	Description
EXHIBIT EGP-1	Map of the KPCo Service Area
EXHIBIT EGP-2	Forest Land Distribution for State of Kentucky

III. CURRENT DISTRIBUTION RELIABILITY PROGRAMS

Q. PLEASE DESCRIBE THE DISTRIBUTION SYSTEM THAT SERVES KPCO'S CUSTOMERS.

A. KPCo serves approximately 172,000 retail customers in Kentucky in a service area that covers approximately 3,780 square miles. KPCo's Distribution System includes approximately 10,000 pole miles of primary and secondary voltage lines. KPCo delivers reliable electric service to our customers by having adequate distribution facilities in place and by working to protect those facilities from hazards that interrupt service.

Q. HOW DOES KPCO CURRENTLY MAINTAIN RELIABILITY ON ITS DISTRIBUTION SYSTEM?

A. KPCo uses a combination of programs to maintain its distribution infrastructure. These programs are designed to reduce the number of service interruptions and to minimize their impact on customers. The programs can be divided into three major categories:

1) Distribution Asset Management;

2) Major Distribution Reliability and Capacity Additions; and

3) Distribution Vegetation Management.

Q. PLEASE DESCRIBE KPCO'S DISTRIBUTION ASSET MANAGEMENT PROGRAMS.

A. The Distribution Asset Management Programs are designed to maximize the efficiency of expenditures and optimize system performance. KPCo has ten Asset Management Programs. The programs and their roles with respect to the distribution system are as follows:

1. *Overhead Circuit Facilities:* Inspection and Maintenance Program: Every two year under this program, KPCo visually inspects its overhead facilities to identify and correct potential problems before they can lead to an outage. Through identifying and repairing such potential problems, KPCo's customers experience fewer service interruptions.
2. *Animal Mitigation Program:* The objective of this Asset Management Program is to reduce the number of animal-caused outages by installing animal guards on line transformers and other line equipment at locations that have had, or potentially may have, a high risk of animal-caused outages.
3. *Capacitor Inspection and Maintenance Program:* The purpose of this program is to inspect and maintain all fixed and switched capacitor installations to ensure these devices are functioning properly. These capacitor installations provide voltage support throughout the KPCo service territory and are a critical component in the implementation of Volt/VAR Optimization (VVO).

4. *Underground Facilities Inspection and Maintenance Program:* Every two years under this Asset Management Program, KPCo visually inspects the external, above-ground portions of underground distribution facilities to identify and correct problems before they can cause an outage. Through these inspections, KPCo identifies and repairs such things as transformers, pedestals, and switchgear.
5. *Pole Inspection and Maintenance Program:* The primary objective of this Asset Management Program is to maintain and prolong the mechanical integrity of KPCo's wood poles. As necessary, poles are treated, treated and reinforced, or replaced. This program helps KPCo identify and replace poles that might otherwise fail and cause power interruptions.
6. *Recloser Maintenance / Replacement Program:* The objective of this program is to perform preventive maintenance on reclosers, or to replace, as needed, recloser units that are not operating properly. When a recloser device senses a fault, the device will automatically open and allow a brief period of time for the cause of the fault to clear from the line. The reclosing equipment will then automatically re-energize the circuit. A recloser that does not open and close properly can turn a momentary interruption into a sustained interruption of service, or result in an interruption to more customers than necessary.
7. *Overhead Conductor Program:* This program minimizes primary and secondary conductor failures by replacing overhead conductors that show signs of wear. Targeted areas generally come from historical reliability

data or from the overhead facilities inspection program where an abnormal number of splices were found in the field for a section of line.

8. *Underground Cable Program:* The objective of this program is to correct underground primary cable deficiencies by restoring the integrity of cable through either cable injection or cable replacement. As is the case with KPCo's Overhead Conductor Program, this program targets areas experiencing circuit interruptions and lessens the likelihood of future interruptions to our customers.

9. *Lightning Mitigation Program:* The objective of this Asset Management Program is to reduce the number of lightning-caused outages through the installation of new lightning arresters at locations within areas known to be prone to lightning-caused outages.

10. *Sectionalizing Program:* This Asset Management Program improves the reliability of KPCo's distribution circuits by adding new, or modifying existing, sectionalizing devices. These sectionalizing devices may be manual pole top switches or automatic devices such as reclosers or fused cutouts. The addition of manual switches where warranted allows the outage duration to be lessened for the customers served by the unaffected portions of the circuit that can be reenergized. Fused cutouts or reclosers work to remove a faulted section of the circuit from service and prevent the entire circuit from experiencing a sustained outage. This enhanced sectionalizing capability results in smaller circuit segments and fewer customers being interrupted after faults occur on distribution circuits.

Q. PLEASE DESCRIBE WHAT IS INCLUDED IN THE MAJOR DISTRIBUTION RELIABILITY AND CAPACITY ADDITIONS PROGRAM.

A. KPCo's planning efforts identify areas where the increasing or shifting demand for electricity is approaching the limit of the Distribution System's existing load capacity. These specific projects re-conductor portions of the existing distribution circuits or allow portions of a circuit to be reconfigured. The expansion of the Distribution System to serve new customers can also result in the upgrade or replacement of distribution facilities to maintain and enhance reliable service to KPCo's customers.

Q. PLEASE DESCRIBE KPCO'S EXISTING DISTRIBUTION VEGETATION MANAGEMENT PROGRAM.

A. KPCo's vegetation management practices are conducted in accordance with standards established by the American National Standards Institute (ANSI), the Occupational Safety and Health Administration (OSHA), and the National Electrical Safety Code (NESC), and include such things as pruning and removing trees; safety and worker protection; work clearances and training requirements; and safety clearance guidelines.

The Company is currently implementing a Commission approved schedule to transition KPCo's Distribution Vegetation Management Program from a performance-based to a cycle-based approach. After the transition is complete, KPCo will trim vegetation adjacent to all distribution circuits on a four-year cycle. The KPCo service territory is located in an area with rugged terrain and dense forests (Compare Exhibit EGP-1 to Exhibit EGP-2.). Once fully implemented, the four-year trim cycle is expected to improve tree-related distribution circuit reliability further through the increased frequency of re-clearing Rights-of-Way (ROW).

IV. CAPITAL INVESTMENT

Q. PLEASE SUMMARIZE THE YEARLY DISTRIBUTION CAPITAL COSTS SINCE THE TEST YEAR END OF THE LAST BASE RATE CASE.

A. The following Table 1 provides a summary of the Distribution Capital Costs since September 30, 2009, and includes FERC Account 107 – Construction Work In Progress (CWIP).

Table 1 - KPCo 2009-2014 Capital Costs ($ Millions)

Category	2009*	2010	2011	2012	2013	2014**	Total
Asset Improvement	$1.7	$7.1	$9.4	$11.4	$8.3	$7.2	$45.0
Customer Service	$3.7	$16.3	$16.1	$18.6	$16.4	$10.1	$81.2
Forestry	$1.7	$1.3	$1.4	$2.5	$3.4	$2.6	$13.0
Other	($0.1)	$0.1	$1.1	$0.7	$0.5	$0.3	$2.6
Reliability	$2.4	$4.7	$7.5	$11.2	$17.8	$5.8	$49.4
System Restoration	$2.8	$1.6	$2.9	$8.8	$2.2	$3.0	$21.4
Total	**$12.3**	**$31.1**	**$38.5**	**$53.2**	**$48.5**	**$29.0**	**$212.6**

* The 2009 period is for October 1, 2009 thru December 31, 2009.
** The 2014 period is for January 1, 2014 thru September 30, 2014.

Q. PLEASE EXPLAIN EACH OF THE CAPITAL PROJECT CATEGORIES.

A. Each year, KPCo completes a significant number of capital projects of varying degrees of complexity and dollar value. The majority of capital projects completed by KPCo can be classified under one of six general categories. The general capital project categories are described as follows:

1. *Asset Improvement*: Asset Improvement projects generally include replacement of obsolete equipment and other aging infrastructure, as well as the addition of new assets that support projects associated with smart grid such as the Distribution Automation – Circuit Reconfiguration

(DACR) technology. DACR projects automatically reconfigure distribution circuits during fault conditions to minimize the impact of outages to the fewest number of customers. These projects include both line and station equipment. This project category also has a significant impact on reducing customer outage minutes and improving customer reliability.

2. *Customer Service*: This category of projects supports new customer facilities, meter installations and other customer requirements.
3. *Forestry*: Forestry capital projects generally involve ROW widening and clearing ROW for new lines. ROW widening continues to be an important initiative to reduce tree contacts and fall-ins, which cause customer outages.
4. *Reliability*: Reliability projects are specific projects that target known reliability issues impacting groups of customers or entire circuits. Also, these projects add capacity to the system, which include new lines or stations, additions to existing facilities, and replacing existing assets with higher capacity assets such as re-conductoring an existing line with an increased conductor size.
5. *System Restoration*: These projects replace assets that have failed. Capital projects completed during storm restoration are typical system restoration projects.

6. *Other*: These are projects that are different from the other project categories and include miscellaneous projects or distribution projects that support other business units.

Capital investment is a key component in the Company's strategy for maintaining the Distribution System and improving system reliability. Another key component is the O&M associated with each of these categories. In the next section of my testimony, I describe the Test Year O&M expense and how it supports each of these capital project categories. Additionally, the O&M inspection and maintenance programs are an important element in the process to identify and prioritize the capital projects that need to be completed.

V. O&M EXPENSES

Q. WHAT IS THE KPCO DISTRIBUTION O&M EXPENSE FOR THE TEST YEAR?

A. KPCo's unadjusted, actual Distribution O&M Expense for the Test Year was approximately $43.8 million. The Test Year for the O&M expense is the 12-month period ending September 30, 2014, and it is based on twelve months of actual expenses.

Q. HOW DOES THE TEST YEAR DISTRIBUTION O&M EXPENSES COMPARE WITH HISTORIC LEVELS FOR KPCO?

A. The test year Distribution O&M expenditures compare favorably with the amounts spent annually during the 2009-2013 periods as shown in Table 2. The actual Test Year Distribution O&M Expenses shown in Table 2 provides the O&M Expense levels necessary during calendar years 2009 through 2013 to support the Distribution Asset Management Programs, as well as the expenditures for the test year.

Table 2 - KPCo Distribution O&M Expenses by Year ($ Millions)

General Category	**2009**	**2010**	**2011**	**2012**	**2013**	**Test Yr**
Asset Improvement	$4.9	$4.6	$5.6	$4.2	$4.6	$4.7
Customer Service	$1.2	$1.6	$1.3	$0.7	$0.8	$1.0
Forestry	$6.6	$12.7	$17.3	$17.2	$17.3	$17.0
Other	$3.8	$13.8	$4.8	$5.4	$4.5	$4.8
Regulatory Asset	$0.0	$0.0	$4.7	$4.7	$4.7	$4.7
Reliability	$1.0	$0.8	$0.5	$0.3	$0.6	$0.6
System Restoration	$12.2	$6.2	$10.2	$7.8	$6.9	$10.9
Grand Total	**$29.7**	**$39.6**	**$44.4**	**$40.4**	**$39.3**	**$43.8**

The expenditures shown in Table 2 are those amounts booked in FERC Accounts 580–598.

Q. PLEASE DESCRIBE THE MAJOR COMPONENTS OF THE DISTRIBUTION O&M EXPENSES INCLUDED IN THE TEST YEAR.

A. The largest O&M expense of the Test Year is the Forestry expense that is required to implement the Company's Distribution Vegetation Management Plan approved by the Commission in Case No. 2009-00459. This level of Forestry expense is expected to continue until the initial re-clear of all distribution circuits are completed, after which time the Forestry expense will be adjusted to the level required to maintain the four-year trim cycle. The System Restoration expense can vary from year-to-year, and is largely dependent on weather events throughout each year. The Customer Service expense provides the necessary O&M to support customer programs and address customer issues. The Asset Improvement expense is the O&M required to support capital additions such as the replacement of poles, towers, fixtures, conductors, line transformers and station equipment. The other major category is the Regulatory Assets expense, which was approved by the Commission to recover the cost of major storm restoration efforts.

VI. DISTRIBUTION VEGETATION MANAGEMENT PLAN

Q. WHY WAS THE KPCO VEGETATION MANAGEMENT PLAN ESTABLISHED BY THE COMPANY?

A. Beginning as early as the Company's 2005 rate case, KPCo recognized the need to secure through ratemaking the additional funding necessary to expand the Company's distribution vegetation management efforts. The Company's service territory includes some of the most rugged and heavily forested terrain in the Commonwealth (See Exhibits EGP-1 and EGP-2). The additional vegetation management expenditures were critical to the Company's efforts to improve its distribution system reliability because vegetation within and outside the Company's ROW can grow into or fall onto the Company's distribution facilities causing outages. As part of the settlement agreement in Case No. 2009-00459, Kentucky Power agreed to increase its vegetation management O&M expenditures by an additional $10 million annually to $17,237,965. In addition, KPCo also agreed to maintain its vegetation management capital expenditures of approximately $2 million annually.

Q. DID THE COMMISSION APPROVE THE SETTLEMENT AGREEMENT, INCLUDING THE COMPANY'S DISTRIBUTION VEGETATION MANAGEMENT PLAN?

A. Yes. On June 28, 2010, the Commission issued an Order approving the unanimous settlement agreement. Under the Order, the increased distribution vegetation management expenditures were to be continued annually until the effective date of the rates established in the Company's next base rate case. In addition to funding the additional $10 million in distribution vegetation management O&M expenditures, the agreement approved by the Commission imposed reporting requirements on the Company. By September 30 of each year, the Company has been required to provide the Commission with a work plan outlining the Vegetation Management Plan expenditures for the following year. Beginning April 1, 2011 and in subsequent years, the Company also has been required to provide the Commission with a report on system reliability and the expenditure of funds for the previous year.

In addition to its immediate effect on distribution system reliability, the Company's distribution vegetation management plan was intended to allow the Company to transition to a four-year re-clearing cycle to enable and maintain the reliability gains.

Q. PLEASE SUMMARIZE THE CURRENT STATUS OF THE KPCO VEGETATION MANAGEMENT PLAN.

A. The Company has completed more than four full years of work under the Plan. It was originally estimated it would take approximately seven years at the approved funding level to re-clear all distribution circuits. As discussed below, it now appears it will take more than seven years at current funding levels to re-clear all distribution circuits. Table 3 provides a summary of the vegetation management work plan as completed through 2014:

Table 3 – Summary of Vegetation Management Plan Completed

Description	2010*	2011	2012	2013	2014**	Total

Circuits Completed	5	20	22	22	18	87
Miles Completed	463	943	878	826	829	3,939
Brush Cut Acres	848	2,419	1,393	1,471	1,297	7,428
Brush Spray Acres	1,372	2,012	1,879	2,549	2,270	10,082
Tree Removal	111,010	232,457	233,676	237,549	184,117	998,809
Tree Trim	46,736	62,618	70,568	79,334	47,197	306,453

* The 2010 period is from June 29 through December 31, 2010.
** The 2014 period is from January 1 through September 30, 2014.

In addition, more complete details of the circuits completed are provided in the annual progress reports filed on or before April 1 of each year.

Q. DOES THE COMPANY MANAGE THE VEGETATION MANAGEMENT PLAN TO THE SPENDING TARGETS AGREED UPON IN CASE NO. 2009-00459?

A. Yes. While the Company strives to achieve the annual target expenditure amounts, it is difficult to achieve the numbers precisely due to unplanned work that may arise, the complexity of the work schedules, the balancing of resources and not knowing the exact amount of overheads that might be applied in the final accounting. Even though any given year may be slightly over or under the target, the Company has met its expenditure obligation for the nearly four and one-half years the program has been in operation. Table 4 provides a summary of the actual vegetation expenditures through September 30, 2014.

Table 4 – Summary of Vegetation Management Plan Costs ($ Million)

Description	2010*	2011	2012	2013	2014**	Total
O&M Expenses	$9.0	$17.3	$17.0	$17.5	$13.3	$74.0
Capital Costs	$0.5	$1.4	$2.5	$3.4	$2.6	$10.5

* 2010 costs are from June 29 through December 31, 2010.
** 2014 costs are from January 1 through September 30, 2014.

The Distribution Vegetation Management Plan expenditures are provided in more detail in the annual progress reports filed on or before April 1 of each year.

Q. HAS THE COMPANY INCREASED THE NUMBER OF VEGETATION CONTRACTOR FULL-TIME-EQUIVALENT (FTE) EMPLOYEES SINCE THE IMPLEMENTATION OF THE VEGETATION MANAGEMENT PLAN?

A. Yes. Since the implementation of the Plan, the Company has more than doubled the vegetation contractor FTE employees. These numbers fluctuate during the year due to the transient nature of these employees and the balancing of these employees by the contractor for work within and outside KPCo. Adding vegetation contract employees requires recruitment and extensive training over multiple years to fully develop the skills necessary to perform the various types of vegetation management work required in KPCo's service territory.

Q. IS THE PLAN ACHIEVING IMPROVED RELIABILITY METRICS?

A. Yes. Table 5 provides a summary of the annual reliability metrics since 2009. The implementation of the Vegetation Management Plan began mid-2010:

Table 5 – Summary of KPCo Reliability Metrics

Description	2009	2010	2011	2012	2013	2014*
SAIFI	2.556	2.470	3.085	2.417	2.144	2.307
CAIDI	194.5	169.4	195.4	189.5	178.5	218.5
SAIDI	497.1	418.4	602.8	458.0	382.7	504.1

* 2014 metrics reflect 12 months ending September.

The details of the Company's annual reliability metrics are provided in the annual progress reports filed on or before April 1 of each year.

Q. PLEASE DEFINE THESE RELIABILITY METRICS AND EXPLAIN HOW THE METRICS ARE USED TO IMPROVE RELIABILITY?

A. SAIDI, CAIDI and SAIFI are defined in IEEE 1366-2012, the "IEEE Guide for Electric Power Distribution Reliability Indices". SAIDI (System Average Interruption

Duration Index) indicates the total duration of interruption for the average customer during a predefined period of time, and it is defined as the "Summation of Customer Interruption Duration" divided by the "Total Number of Customers Served". CAIDI (Customer Average Interruption Duration Index) represents the average time required to restore service to customers, and it is defined as the "Summation of Customer Interruption Duration" divided by the "Total Number of Customers Interrupted". SAIFI (System Average Interruption Frequency Index) indicates how often the average customer experiences a sustained interruption on an annual basis, and is defined as the "Summation of the Total Number of Customers Interrupted" divided by the "Total Number of Customers Served". By monitoring these metrics over an extended period of time, the Company can determine if its reliability strategy is achieving the desired goals or if the strategy need to be modified to achieve the desired results.

Q. SINCE THE PROGRAM BEGAN IN 2010, KPCO HAS EXPENDED ALMOST $85 MILLION ON ITS DISTRIBUTION VEGETATION MANAGEMENT PROGRAM. WHY HAVE THE RELIABILITY METRICS NOT IMPROVED MORE OVER THE PAST FOUR YEARS?

A. In addition to vegetation in the ROW, the principal target of the Company's Distribution Vegetation Management Program, reliability metrics are also affected by external factors such as weather and tree contact from outside the ROW. These external factors are neither predictable nor controllable by the Company, and can make year-to-year comparisons misleading.

For instance, as the Company improves vegetation management within its ROW and continues its asset management programs, weather events will cause less damage to the utility system. Storms that would have produced enough damage to be categorized as major events in the past may now result in less, but still significant damage. This can result in the SAIDI metric actually worsening since major events are excluded from the index calculations, but the less damaging storms cannot be excluded. As an example, this situation occurred during a severe ice storm that began the evening of February 4, 2014 and continued into February 5. The Company's response to the outages resulting from that storm was immediate and extensive. However, due to the immediate and extensive Company response, the improved ROW, and the storm outages partially spanning two different days, this severe storm was not considered a major event by the IEEE methodology and regulatory rules. These two days contributed fifty-three minutes toward the Company's SAIDI metric in 2014. If this storm had occurred in a previous year, it would likely have been excluded as a major event. See Graphs 2 and 3 to see the impact of this single storm on the SAIDI metrics.

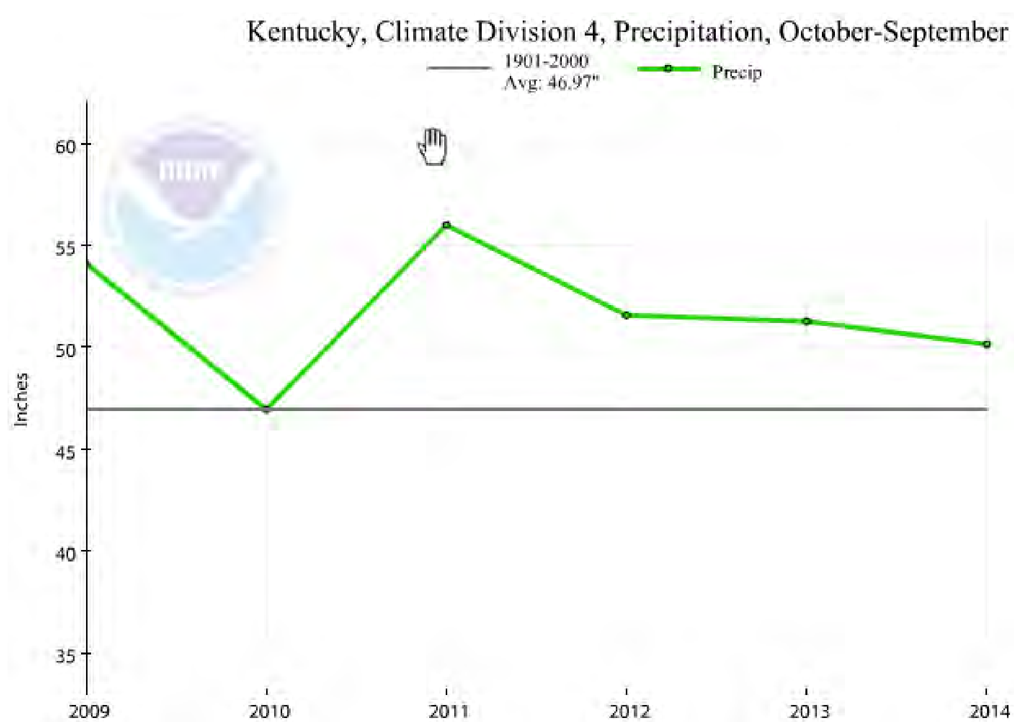
Q. PLEASE EXPLAIN HOW PRECIPITATION CAN AFFECT RELIABILITY METRICS.

A. While excessive rainfall in itself typically does not cause outages, the wind and lightning associated with an increased number or length of storms can increase unexpected outages. The higher than normal rainfall also causes an increase in the vegetation growth rates. This increased vegetation growth increases the likelihood of vegetation outages, and because increased amounts of vegetation must be removed, slows the Company's re-clearing efforts.

Q. DID THE COMPANY'S SERVICE TERRITORY EXPERIENCE HIGHER THAN NORMAL LEVELS OF PRECIPITATION FOR ANY PORTION OF THE PERIOD 2009-2014?

A. Yes. The average annual rainfall for Kentucky is approximately 47 inches per year. In the twelve months ending September 2011, the average rainfall was 56 inches or approximately 19 percent above normal. From October 2011 through September 2014, the average September twelve-month ending rainfall has consistently been above normal. Graph 1 below illustrates precipitation levels experienced in Eastern Kentucky from 2009 – 2014:

Graph 1 – Illustration of Eastern Kentucky 12-Month Precipitation



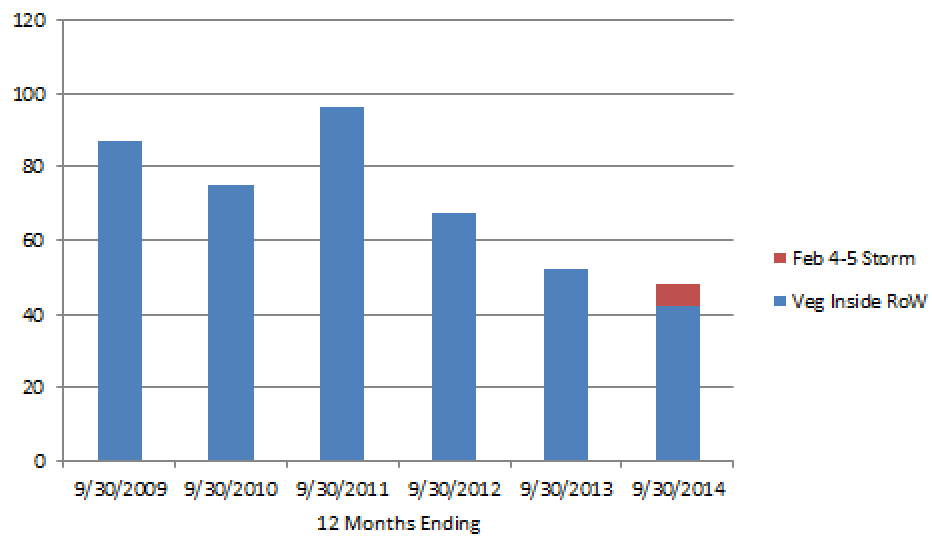
Data Source: NOAA website, http://www.ncdc.noaa.gov/cag/time-series/us

The 2011 spike in precipitation corresponds with the decrease in the Company's reliability indices.

Q. WHAT OTHER EVIDENCE DOES THE COMPANY HAVE THAT ITS DISTRIBUTION VEGETATION MANAGEMENT PROGRAM HAS IMPROVED ITS DISTRIBUTION SYSTEM RELIABILITY?

A. The principal focus of the Company's Distribution Vegetation Management Plan is the elimination of vegetation within the Company's ROWs. This vegetation, which typically is in closest proximity to the Company's distribution facilities, is most likely to result in system outages. As evidenced by Graph 2 below, the Company's Distribution Vegetation Management Program has reduced the SAIDI for interruptions resulting from tree contact from inside the ROW.

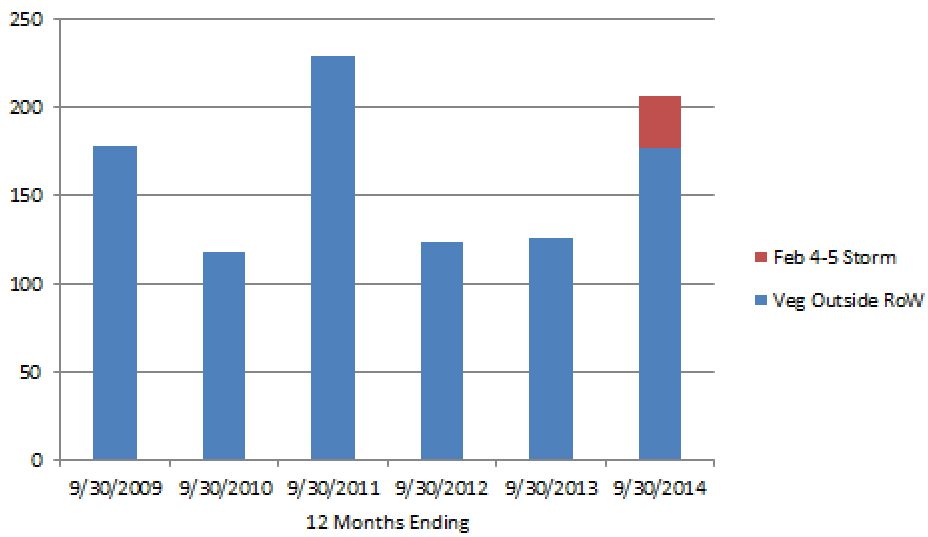
Graph 2 – KPCo SAIDI from Vegetation Inside the ROW



Note: Excludes Major Storms

This improvement contrasts with the lack of improvement in outage duration in connection with outages caused by vegetation outside the ROW:

Graph 3 – KPCo SAIDI from Vegetation Outside the ROW



Note: Excludes Major Storms

Q. YOU JUST INDICATED THAT THE FOCUS OF THE COMPANY'S DISTRIBUTION VEGETATION MANAGEMENT PROGRAM HAS BEEN VEGETATION WITHIN THE COMPANY'S ROW. DOES KPCO IGNORE VEGETATION OUTSIDE ITS ROW?

A. No. The Company is also alert to, and seeks to address, danger trees outside its ROW. Danger trees are trees that may be distressed due to disease, insect damage, dead limbs, or that lean toward the ROW, or that pose a danger of falling into the Company's distribution facilities because of loose soil conditions or exposed roots. A distribution ROW typically varies between thirty- and forty-feet wide. If a sixty-foot tree falls from just outside the ROW, it will likely make contact with the distribution circuit. This problem is further exacerbated when the danger tree is on a hillside above the ROW. With the aid of gravity, the danger tree can easily end up in the ROW if the tree falls.

Q. WHAT IS THE COMPANY DOING TO ADDRESS THE INCREASE IN OUTAGES CAUSED BY VEGETATION OUTSIDE THE ROW?

A. When trees are removed from outside the ROW, the Company must work with property owners to obtain permission and address any concerns. This can result in additional costs and delays. The Company has increased the amount of its capital spending (tree removals are charged to capital if the ROW is widened) to widen existing ROWs and to remove additional danger trees outside the ROW. As shown in Table 4 above, KPCo's capital costs have been increasing each year to support efforts to address outages caused by vegetation outside the ROW.

Q. ARE THERE OTHER FACTORS THAT IMPACT THE COST OF REMOVING TREES FROM WITHIN OR OUTSIDE THE ROW?

A. Yes. As indicated in Exhibit EGP-2, the KPCo service territory has the highest volume of trees with a diameter greater than five inches within the Commonwealth of Kentucky. In order for vegetation contractors to safely remove a tree equal to or greater than five inches, roping of the tree is required. The safety rule states that the tree shall be properly notched and back cut, and a rope shall be used to direct its fall in the required (intended) direction. This rule helps to protect vegetation workers from trees falling in an unintended direction, but it also requires more time and cost to cut down the tree. This rule also reduces the risk a tree will unintentionally fall into the distribution line and cause an outage.

Also, herbicide application is a vital component of the KPCo Vegetation Management Program. Judicious use of herbicides is cost effective and efficient, and a best management practice for achieving the goal of establishing low-growing plant cover in the ROW that has been cleared. The spray program is essential in establishing and maintaining a four-year cycle. The long-term benefits include improved reliability, a reduction in future ROW maintenance costs, and improved access to the KPCo's distribution facilities. KPCo typically treats between 2,000 to 3,000 acres of brush each year. Treatment methods include high-volume foliar, basal treatment, stump application, low-volume foliar and aerial application.

Q. ARE THE ACTIVITIES TO WIDEN THE ROW AND REMOVE DANGER TREES OUTSIDE THE ROW YIELDING ANY POSITIVE RESULTS?

A. Yes. Even though the Company is seeing an increase in the number of outages due to vegetation contact outside the ROW in 2014, more of the SAIDI duration minutes were caused by trees from outside the ROW on lines that have not been cleared versus lines that have been cleared by a two-to-one ratio. Currently, the danger trees are only being removed from outside the ROW on the distribution lines actively being cleared. As the Company continues to clear distribution lines end-to-end, widen ROWs and remove danger trees, it is expected that fewer trees from outside the ROW will impact SAIDI.

VII. PROPOSED MODIFICATION OF THE COMPANY'S EXISTING DISTRIBUTION VEGETATION MANAGEMENT PLAN

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS EXISTING DISTRIBUTION VEGETATION MANAGEMENT PLAN?

A. Yes. The original 2010 Vegetation Management Plan work and completion estimates were based on the best information available at the time. Since that time, the Company has gained multiple years of experience and can better estimate the unit costs required for the various types of vegetation work, the number of hours needed to perform the work, as well as the total work that needs to be completed. For example, the Company originally estimated that 763,000 trees would need to be removed to re-clear its distribution system in its entirety. In the first four years of the program, the Company has already removed over a million trees. Additionally, since undertaking the current plan, the Company determined that the amount of vegetation in or in close proximity to its energized facilities and the time it would take to safely and productively increase the vegetation management workforce to higher staffing levels had both been underestimated. Moreover, above-normal precipitation has also contributed to higher vegetation growth rates and increased the required work to clear and keep the ROW clear. Based on this experience, the Company now estimates it will require eight and one-half years to complete the re-clearing of every circuit instead of the original estimate of seven years.

Q. WHAT CHANGES TO THE VEGETATION MANAGEMENT PLAN ARE BEING PROPOSED BY KPCO?

A. There are three fundamental tasks that are required at specific intervals to complete the transition from the former performance-based vegetation management program to a four-year cycle-based vegetation management program:

1. The first task is the initial end-to-end re-clearing of every distribution circuit ROW as contemplated by the unanimous settlement agreement. This task originally was estimated to take approximately seven years (transition period). In fact, as discussed above, it now appears eight and one-half years will be required.

2. The second task is the interim maintenance or subsequent second pass-through prior to the establishment of a four-year cycle. If undertaken

within four to five years of the initial re-clearing, this second task can be performed at the lower maintenance cost. If delayed more than four to five years from the initial re-clearing of the vegetation growth, this second task requires funding at the higher re-clearing cost levels.

3. The third task is the initiation of the four-year cycle through the clearing at "maintenance cost levels" of approximately one-fourth of the distribution circuit ROW miles each year.

Q. HOW DOES THE COMPANY PROPOSE TO IMPLEMENT THESE MODIFICATIONS?

A. These tasks can be accomplished through different scenarios. The primary difference between the scenarios is the timing, duration, and cost of the three tasks described in the previous response. KPCo's 2015 Distribution Vegetation Management Plan, which was filed September 30, 2014, presented three scenarios for the establishment of a four-year maintenance cycle. In addition, following a meeting with Staff and a representative of the Office of the Attorney General in October 2014, the Company developed a fourth scenario. The following Tables 6 – 9 illustrate the types and timing of tasks (as described above) being undertaken each year to implement a four-year cycle.

Under Scenario 1, the first task will continue at the funding levels established in the Unanimous Settlement Agreement in Case No. 2009-00459. The first task will be completed by the end of 2018. Beginning with the completion of the first task, the company in 2019 will begin the second pass through or the start of the second task at a higher re-clear cost. Eight and one-half years will have elapsed before the second pass-through begins. After this much time, vegetation will have grown back into the energized lines thereby requiring the more extensive and costly work at re-clear cost levels. Beginning in 2023, the third task will be completed at a lower maintenance cost level as circuits were previously cleared four years prior. See the following Table 6 for the timing of the tasks in Scenario 1:

Table 6 – Scenario 1

Table 6: Scenario 1

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Yr 1 Miles	463					8.5 years growth				2016		4 years growth		2016
Yr 2 Miles		932									2016			
Yr 3 Miles			891									2016		
Yr 4 Miles				826									2016	
Yr 5 Miles					1008									
Yr 6 Miles						987								
Yr 7 Miles							986							
Yr 8 Miles								986						
Yr 9 Miles									986					
Program Miles	463	932	891	826	1008	987	986	986	986	2016	2016	2016	2016	2016

Task 1 - # Miles (Unanimous Settlement Agreement)
Task 2 - # Miles at Re-Clear Cost (Start at 8.5 yrs growth)
Task 3 - # Miles at Maintained Cost (4 yrs growth)

Under Scenario 2, the Company continues the first task at the funding levels established in the Unanimous Settlement Agreement in Case No. 2009-00459. As in Scenario 1, the first task will be completed by the end of 2018. However, starting in mid-2015, the second task, which targets those circuits previously cleared in the latter half of 2010 and at the beginning of 2011, is initiated. Additional funds beginning at the start of the second task will be required to perform the interim clear. During the 2015-2018 periods, the vegetation management program will be working on both the first and second task. The second task will be at a lower maintenance cost due to the shorter time elapsed between the initial and interim clearings. The third task will begin in 2019 at a lower maintenance cost as those circuits scheduled to be trimmed will have been cleared within the four to five year window. See the following Table 7 for the timing of the tasks in Scenario 2:

Table 7 – Scenario 2

Table 7: Scenario 2

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Yr 1 Miles	463	← 5 years growth			→	741	← 4 years growth		→	2016	← 4 years growth		→	2016
Yr 2 Miles		932					771				2016			
Yr 3 Miles			891					788				2016		
Yr 4 Miles				826					812				2016	
Yr 5 Miles					1008									
Yr 6 Miles						987								
Yr 7 Miles							986							
Yr 8 Miles								986						
Yr 9 Miles									986					
Program Miles	463	932	891	826	1008	1728	1757	1774	1798	2016	2016	2016	2016	2016

Blue	Task 1 - # Miles (Unanimous Settlement Agreement)
Yellow	Task 2 - # Miles Interim Clear at Maintained Cost (4 - 5 yrs growth)
Red	Task 3 - # Miles at Maintained Cost (4 yrs growth)

Under Scenario 3, the Company will complete the initial re-clearing in mid-2017 as initially projected in Case No. 2009-00459. To do so will require increased funding beginning in 2015 in order for the first task to be completed. Upon completion of the first task, the Company will begin mid-2017 the second pass-through or the second task on its circuits. The higher associated cost with the second task will be at re-clearing cost levels as seven years will have passed since the initial re-clear. Vegetation will have grown back into the energized lines thereby requiring the more extensive and costly work. In 2021, the third task will begin at the lower maintenance cost as those circuits scheduled to be trimmed will have been cleared within the previous four years. See the following Table 8 for the timing of the tasks in Scenario 3:

Table 8 – Scenario 3

Table 8: Scenario 3

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Yr 1 Miles	463			← 7 years growth →				1039		← 4 years growth →		1227		
Yr 2 Miles		932							2079				2016	
Yr 3 Miles			891							2079				2016
Yr 4 Miles				826							2079			
Yr 5 Miles					1008							789		
Yr 6 Miles						1578								
Yr 7 Miles							1578							
Yr 8 Miles								789						
Program Miles	463	932	891	826	1008	1578	1578	1828	2079	2079	2079	2016	2016	2016

Task 1 - # Miles (Unanimous Settlement Agreement)
Task 2 - # Miles at Re-clear Cost (7 yrs growth)
Task 3 - # Miles at Maintained Cost (4 yrs growth)

Under Scenario 4, the Company will complete the initial re-clearing or the first task in mid-2017 as initially projected in Case No. 2009-00459. However, starting in mid-2015, the second task, which targets those circuits previously cleared in the latter half of 2010 and the beginning of 2011, is initiated. Increased funding beginning in 2015 will be required to complete the first task or the initial re-clear along with additional funds for the start of the second task or to perform the interim clear. During 2015 to mid-2017, the vegetation management program will be working on both the first and second task. The second task will be at a lower maintenance cost due to the shorter time elapsed between the initial and interim clearings. Upon completion of the first and second task, the third task will begin in mid-2017 at a lower maintenance cost as those circuits scheduled to be trimmed will have been cleared within the four to five year window. See the following Table 9 for the timing of the tasks in Scenario 4:

Table 9 – Scenario 4

Table 9: Scenario 4

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Yr 1 Miles	463	← 5 years growth →				663		1008	← 4 years growth →			2016		
Yr 2 Miles		932					732		2016				2016	
Yr 3 Miles			891					219		2016				2016
Yr 4 Miles				826							2016			
Yr 5 Miles					1008									
Yr 6 Miles						1578								
Yr 7 Miles							1578							
Yr 8 Miles								789						
Program Miles	463	932	891	826	1008	2241	2310	2016	2016	2016	2016	2016	2016	2016

Task 1 - # Miles (Unanimous Settlement Agreement)
Task 2 - # Miles Interim Clear at Maintained Cost (4 - 5 yrs growth)
Task 3 - # Miles at Maintained Cost (4 yrs growth)

Q. YOU INDICATE THE MAINTENANCE COST LEVEL IS LESS THAN THE CLEARING COST LEVEL. WHAT ARE THE ESTIMATED COSTS OF THE TWO LEVELS OF WORK?

A. For 2015, the Company estimates re-clearing costs of $17,605 per mile. This estimate is based upon the actual per mile initial clearing costs incurred by KPCo in the first three quarters of 2014. This estimate requires a one percent cost per mile improvement over 2014, but with the inflation cost estimated at two percent, an actual three percent improvement is required to attain the 2015 re-clearing mileage. The 2015 maintenance level costs are estimated at $10,563, or sixty percent of the re-clearing cost.

Q. IS THE WORK PROPOSED TO BE PERFORMED BEYOND THE INITIAL CLEARING OF THE COMPANY'S DISTRIBUTION SYSTEM RELATED TO THE DELAY IN THE COMPLETION OF THE INITIAL SYSTEM CLEARING?

A. No. Even if the Company had been able to complete the initial clearing within the previously estimated seven years, some sort of interim funding increase would have been required to allow KPCo to implement the four-year cycle at the maintenance cost level.

Q. WHAT WILL BE THE OVERALL COST OF THE IMPLEMENTATION OF A FOUR YEAR CYCLE AT MAINTENANCE COST LEVEL?

A. The final cost depends on the scenario selected. Among the variables affecting both the annual and overall cost are:

- Whether subsequent re-clearings are performed within four to five years of the initial clearing, subsequent re-clearings within four to five years of the initial clearing can be performed at the maintenance cost level, which is approximately sixty percent of the initial clearing cost. After five years, the cost of clearing increases to the initial clearing cost because of the amount of vegetation that will have grown since the initial clearing.
- Whether Roving Crews from outside the area must be deployed, Scenarios 2, 3 and 4, for example, require the additional cost of Roving Crews, which are temporary tree crews from outside the KPCo service area. These Roving Crews require a higher premium pay to provide for temporary housing and meal allowances since these crews are working outside their normal work areas. The AEP System has experienced an estimated additional expenditure of one and one-half times the cost per mile where these types of crews have been used in the past.
- The length of ROW being cleared and the particular task being performed in any year can impact costs. For example, Scenario 4 requires 2,310 miles of ROW to be cleared in 2016. Distributing the mileage into the specific task,

1,578 miles at re-clear cost (Task 1) and 732 interim clear miles at maintained cost (Task 2), Scenario 2, by contrast, projects only 1,752 of ROW being cleared for the same year. The required mileage for the specific tasks is 986 miles at re-clear cost (Task 1) and 771 interim clear miles at maintained cost (Task 2).

The Table 10 below provides a cost comparison of each of the proposed scenarios:

Table 10 – Scenario Cost Comparison

Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2010	$8,950,346	$8,950,346	$8,950,346	$8,950,346
2011	$17,261,128	$17,261,128	$17,261,128	$17,261,128
2012	$17,029,248	$17,029,248	$17,029,248	$17,029,248
2013	$17,466,579	$17,466,579	$17,466,579	$17,466,579
2014	$17,237,965	$17,237,965	$17,237,965	$17,237,965
2015	$17,237,965	$27,661,060	$24,304,356	$40,801,455
2016	$17,237,965	$27,664,598	$24,790,443	$41,125,000
2017	$17,237,965	$27,661,949	$29,292,312	$29,775,649
2018	$17,237,965	$27,664,089	$33,980,685	$21,456,386
2019	$38,462,690	$20,251,822	$34,660,298	$20,251,822
2020	$38,462,690	$20,049,303	$35,353,504	$20,049,303
2021	$37,697,283	$19,848,810	$26,454,828	$19,848,810
2022	$37,320,310	$19,650,322	$21,402,966	$19,650,322
2023	$19,453,819	$19,453,819	$19,453,819	$19,453,819
Total	**$317,909,291**	**$287,851,038**	**$327,638,477**	**$310,357,832**

Q. WHICH SCENARIO DOES THE COMPANY PREFER?

A. The Company proposes Scenario 2 as the best alternative for improving vegetation-related reliability and completing the transition to a four-year cycle at maintenance cost levels. This scenario will transition the vegetation management program over to a four-year cycle-based program in the most efficient process, at the least cost, and with the fewest additional forestry employees over the long range plan. The Company, however, remains receptive to the input of other stakeholders as these various scenarios are discussed and considered.

Q. DOES THE COMPANY NEED A RELIABILITY ADJUSTMENT TO THE TEST YEAR O&M TO SUPPORT THE PROPOSED SCENARIO 2?

A. Yes. The details of the reliability adjustment are shown in Section V, Exhibit 2, W19. The annual reliability amount approved in Case No. 2009-00459 is $17,237,965. The total reliability adjustment recommended to support Scenario 2 is $10,655,900 as shown on Line No. 7. This reliability adjustment would need to be modified if the scenario is modified or if a different scenario is selected.

VII. CONCLUSION

Q. MR. PHILLIPS, PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company remains committed to establishing and maintaining a four-year vegetation maintenance cycle for distribution circuits. Since the conception of the Vegetation Management Plan, the Company has worked through the details of developing and implementing the Plan. As the Plan has evolved, the Company has improved the processes for estimating the time required to complete the various vegetation maintenance activities, the costs associated with those activities and the overall resources needed to complete the Plan commitment to ensure customers achieve acceptable reliability.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Exhibit EGP-1: Map of the KPCo Service Area

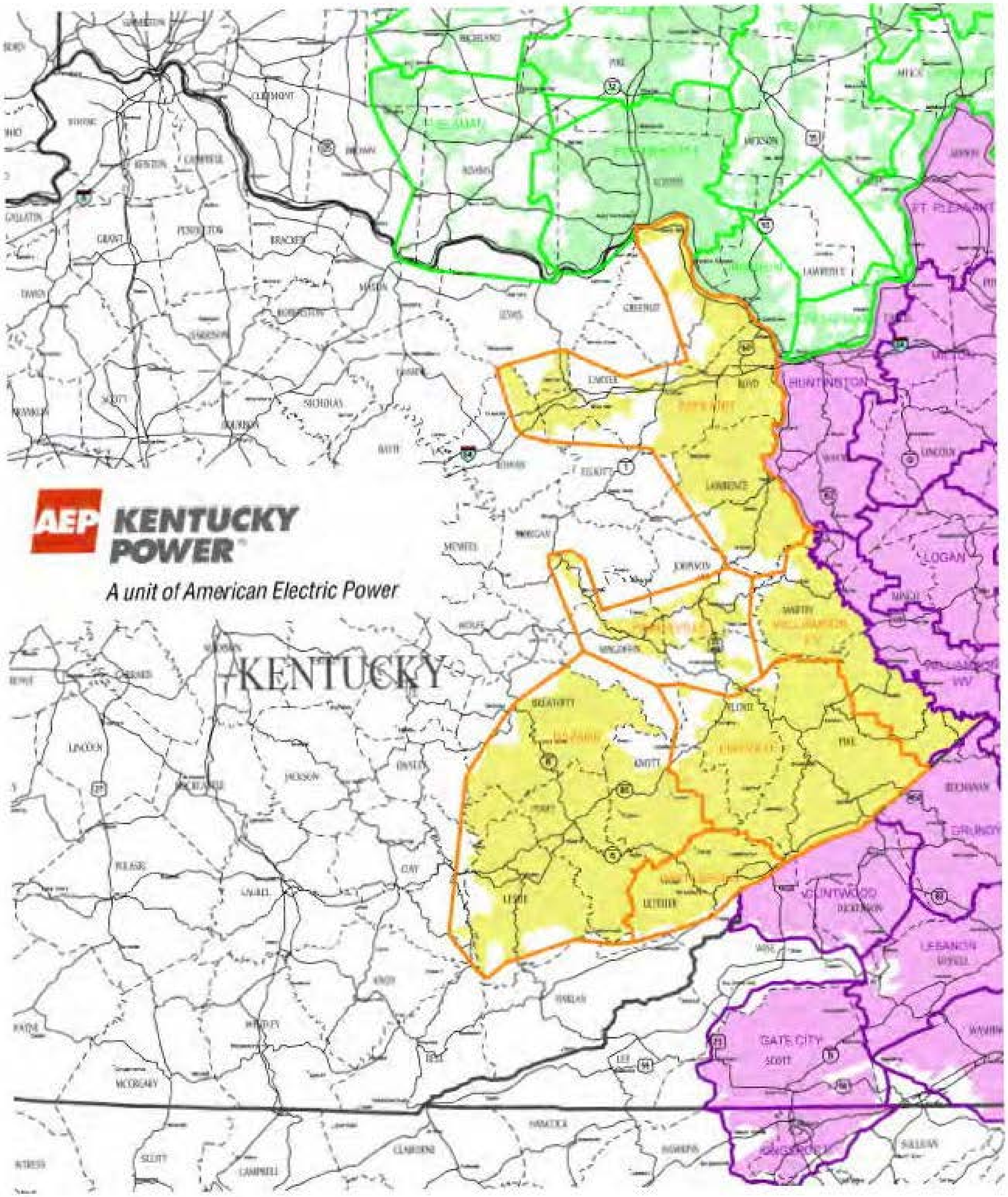
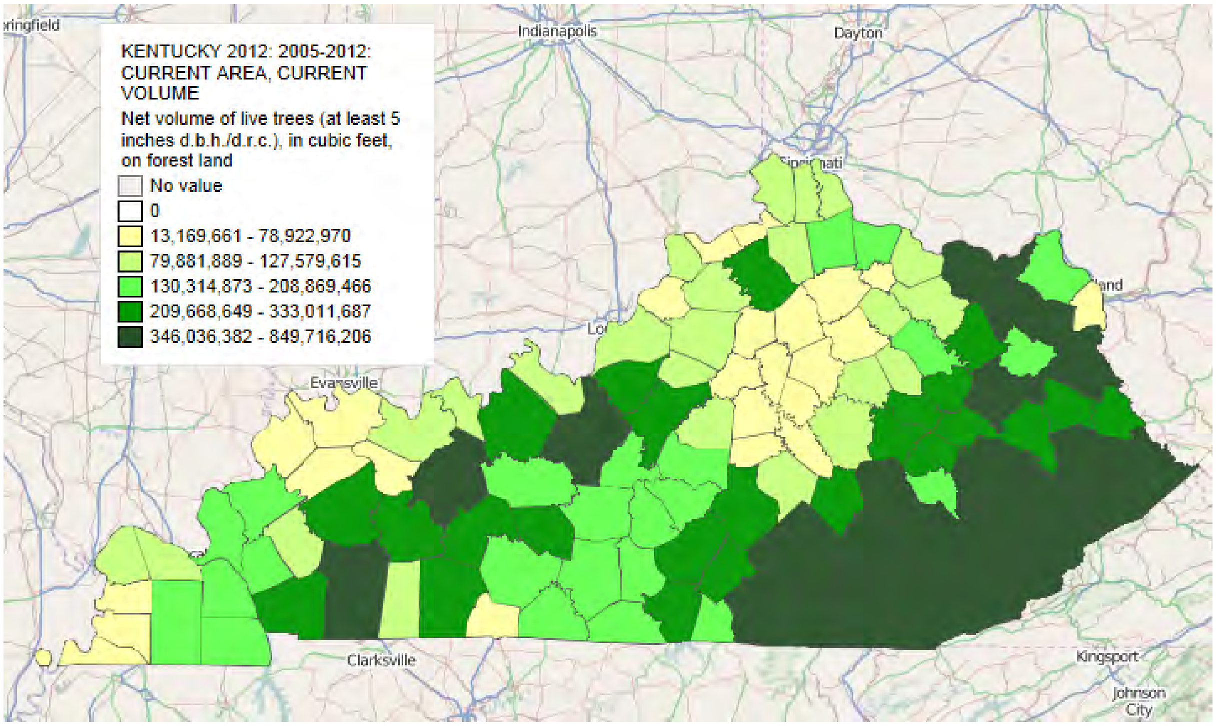


Exhibit EGP-2: Forest Land Distribution for State of Kentucky



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	**)**	
A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	
Environmental Compliance Plan; (3) An Order	**)**	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

MARC D. REITTER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Marc D. Reitter, being duly sworn, deposes and says he is the Managing Director, Corporate Finance for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

____
Marc D. Reitter

STATE OF OHIO)
) Case No. 2014-00396
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Marc D. Reitter, this the 10th day of December, 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

DIRECT TESTIMONY OF
MARC D REITTER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

**DIRECT TESTIMONY OF
MARC D REITTER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

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

A. My name is Marc D. Reitter. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation (AEPSC) as Managing Director of Corporate Finance. AEPSC, a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), provides centralized professional and other services to subsidiaries of AEP. AEP is the parent company of Kentucky Power Company (Kentucky Power or Company) and AEPSC is Kentucky Power's services provider company.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science in Business Administration from Arizona State University in 2000. I earned a Master of Business Administration from the Fisher College of Business at The Ohio State University in 2007. In January 2002, I was hired by AEPSC as an analyst in its AEP Texas Retail Group. I transferred to the Utility Group Business Services in December 2002 as a financial analyst. In December 2004, I was promoted to the Strategic Initiatives Group as a financial analyst. In February 2007, I transferred into the Corporate Finance Group as a financial analyst and progressed to Corporate Finance Manager in February 2010.

In October 2014, I was promoted to my current position as Managing Director of Corporate Finance.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF CORPORATE FINANCE?

A. My responsibilities include planning and executing the corporate finance programs of the regulated operating companies in the AEP System, including Kentucky Power. I am also responsible for preparing dividend payment recommendations for the companies in the AEP System, establishing capitalization targets, and managing the relationships between AEP and its subsidiaries with the credit rating agencies.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before the Public Service Commission of Kentucky Case No. 2009-00459 and submitted testimony in Case No. 2013-00197 on behalf of Kentucky Power.

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

A. Yes. I have submitted testimony and testified before the Virginia State Corporation Commission in Docket No. PUE-2011-00037 on behalf of Appalachian Power Company (APCO), an AEP operating company. In addition, I have submitted testimony and testified on behalf of APCO before the Public Service Commission of West Virginia in Docket No. 10-0699-E-42T. I have also submitted testimony and testified before the Public Utility Commission of Texas in Docket No. 40443 on behalf of Southwestern Electric Power Company, another operating company of AEP. Further, I have submitted testimony before the Michigan Public Service

Commission in Docket No. U-16801 on behalf of Indiana Michigan Power Company, an operating company of AEP and most recently submitted testimony before the Indiana Utility Regulatory Commission in Cause No. 44543 on behalf of Indiana Michigan Power Company.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to support certain historical and adjusted data incorporated in this application. I will sponsor Kentucky Power Company's proposed capital structure and cost of capital for ratemaking purposes, employing the cost of common equity, supported by Company witnesses Avera and McKenzie.

Q. **ARE YOU SPONSORING ANY SCHEDULES INCLUDED IN THE COMPANY'S FILING?**

A. Yes. I am sponsoring the following Section V schedules and workpapers:

- Section V Workpaper S-2 Page 1 of 3
- Section V Schedule 3 (Columns 3 and 4, Lines 1-4)
- Section V Workpaper S-3 Pages 1 and 2

Q. **WERE THE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECTION?**

A. Yes.

IV. PROPOSED COST OF CAPITAL AND CAPITAL STRUCTURE

Q. WHAT IS KENTUCKY POWER'S PROPOSED COST OF CAPITAL FOR RATEMAKING PURPOSES?

A. For the test year ended September 30, 2014, Kentucky Power's proposed after-tax weighted average cost of capital is 7.71%, as illustrated on Section V, Workpaper S-2, page 1 of 3.

Q. HAS KENTUCKY POWER'S DEBT TO CAPITALIZATION RATIO RETURNED TO A LEVEL APPROXIMATING THE LEVEL THAT EXISTED PRIOR TO THE TRANSFER TO KENTUCKY POWER OF A FIFTY-PERCENT UNDIVIDED INTEREST IN THE MITCHELL GENERATING STATION AND RELATED ASSETS AND LIABILITIES?

A. Yes. On December 31, 2013, and in accordance with the Commission's October 7, 2013 Order in Case No. 2012-00578, a fifty percent undivided interest in the Mitchell generating station, along with related assets and liabilities, was transferred from Ohio Power to Kentucky Power ("Mitchell Transfer"). As described in the application and testimony in Case No. 2012-00578, the Mitchell Transfer significantly increased the Company's equity and thereby reduced its debt to capitalization ratio. The Company recapitalized following the Mitchell Transfer in order to restore the Generally Accepted Accounting Principles (GAAP) debt to total capitalization ratio to approximately fifty four percent, which was the Company's debt to capitalization level prior to the Mitchell Transfer.

Q. HOW WAS THE RECAPITALIZATION ACCOMPLISHED?

A. During 2014, Kentucky Power both reduced its equity and increased its debt as part of the recapitalization required to restore the Company's debt to capitalization ratio to pre-Mitchell Transfer levels equal to approximately 54%.

Q. PLEASE SUMMARIZE THE PERMANENT LONG-TERM DEBT FINANCING EMPLOYED BY KENTUCKY POWER AS PART OF ITS RECAPITALIZATION.

A. As authorized by the Commission's March's 25, 2014 Order, the Company permanently refinanced $265 million of long-term debt associated with the Mitchell Transfer. The $200 million in intermediate term loan debt, carrying an average interest rate of 1.44% was refinanced with private placement senior unsecured notes at a weighted average rate of 4.24%. In addition, Kentucky Power refinanced the $65 million tax-exempt pollution control bonds at an initial rate of 0.90%.

Q. PLEASE DESCRIBE THE EQUITY DISTRIBUTIONS ASSOCIATED WITH KENTUCKY POWER'S RECAPITALIZATION.

A. In order to restore Kentucky Power's debt to capitalization ratio to the level approximating the level prior to the Mitchell Transfer, the Company distributed $155 million to its Parent Company in the form of dividends and returned paid-in-capital associated with the Mitchell Transfer.

Q. PLEASE EXPLAIN HOW THE PROPOSED AFTER-TAX WEIGHTED AVERAGE COST OF CAPITAL OF 7.71% WAS CALCULATED.

A. The overall cost of capital is based on a weighting of the costs for the Company's sources of capital, including long-term debt, short-term debt, common stock, accounts receivable financing, and investment tax credits. The Company started with the Reapportioned Kentucky Jurisdiction capital as calculated on Section V Schedule 3 Column 14 for each category of capital. Next, as illustrated on Section V, Workpaper S-2 page 1 of 3, the Company divided the dollar amount of each component of capital by the Company's total dollar amount of capital to derive the percentage of the Company's total capital each component represents.

Q. PLEASE EXPLAIN WHAT RATES WERE USED IN CALCULATING THE COMPANY'S PER BOOKS WEIGHTED AVERAGE COST OF CAPITAL AS OF SEPTEMBER 30, 2014.

A. The weighted cost of long-term debt was determined by taking the sum of each bond's actual annualized cost and dividing this amount by the total net proceeds outstanding as of September 30, 2014. The annualized cost for each bond was calculated by multiplying the effective cost rate (yield to maturity) by the net proceeds outstanding. The effective cost rate, or yield to maturity, is the bond's yield expressed as an annual rate in relation to the face value of the bond. As such, a bond's annualized cost is calculated by multiplying the yield to maturity by the face value of the bond. The sum of the annualized costs is then divided by the total net proceeds outstanding to determine the weighted cost of the long-term debt portfolio.

The cost of short-term debt used in the calculation is the Company's actual short-term interest expense for the twelve months ended September 30, 2014 divided by the actual average borrowings outstanding during the same time period. Please refer to Section V, Workpaper S-3, page 2 of 4.

The cost of accounts receivable financing used in the derivation of the weighted average cost of capital was calculated by using a thirteen month average cost experienced by the Company during the test year.

The cost of common equity used in the calculation is the amount recommended by Company Witnesses Avera and McKenzie.

Q. DID THE COMPANY INCLUDE ANY PRO FORMA ADJUSTMENTS TO THE DEBT COMPONENT OF THE COMPANY'S PER BOOKS CAPITAL STRUCTURE AS OF SEPTEMBER 30, 2014?

A. Yes. The Company made three pro forma adjustments to long-term debt as shown within Section V, Workpaper S-3, page 1 of 4.

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENTS MADE TO THE DEBT COMPONENT OF THE COMPANY'S PER BOOKS CAPITAL STRUCTURE AS OF SEPTEMBER 30, 2014.

A. The net pro forma long-term debt adjustment reflected on Section V, Schedule 3 is $5 million. The net adjustment is derived by taking the September 30, 2014 per books debt balance and substituting the $80 million intermediate term loan debt with $80 million private placement senior unsecured notes that will fund on December 30, 2014. In addition, the Company's debt capitalization increased by $25 million in local bank term loan initial funding approved by the Commission's September 26, 2014 Order in Case 2014-00210. Finally, the $20 million affiliated note was retired in October 2014 thereby decreasing the Company's debt capitalization. Details of each of the three pro forma adjustments are described below:

<u>Intermediate Term Loan Refinancing</u>

The Company issued new permanent long-term private placement senior unsecured notes in the amount of $200 million. The proceeds were dedicated to retiring the Company's intermediate $200 million term loan debt obligation that was assumed as part of the Mitchell Transfer. The private placement transaction closed in July 2014 and was structured with two delayed draw tranches: $120 million Series A that funded September 30, 2014, and $80 million Series B that will fund December 30, 2014. The debt component of the Company's capital structure has been adjusted to reflect the permanent financing of the $80 million intermediate term loan obligation with $80 million fixed private placement senior unsecured notes that will fund on December 30, 2014. As a result of the delayed draw feature on the private placement senior unsecured notes, the Company continued to accrue and pay interest on the variable rate intermediate term loan debt at approximately 1.44% versus the fixed 4.24% weighted average coupon of the private placement senior unsecured notes. The delayed funding allowed the Company to utilize the lower cost of funds from the intermediate term loan debt from when the refinancing event closed in July 2014 through the September and December funding dates of the permanent private placement senior unsecured notes. This resulted in the Company achieving approximately $1.9 million in long-term interest expense savings in 2014.

Affiliated Note Early Retirement

On October 10, 2014, the Company extinguished the existing 5.25% affiliated note payable to AEP Parent. The debt component of the capital structure was adjusted properly to reflect the early retirement. In addition, by redeeming the affiliated debt prior to its maturity of June 1, 2015, the

Company was able to forego the remaining scheduled interest payments and generate approximately $673,000 of long-term debt interest expense savings.

Local Bank Term Loan Financing

On November 5, 2014, the Company entered into a four year variable rate $75 million unsecured term loan facility with local Kentucky banks. An adjustment was made to the debt component of the capital structure to reflect the Company's initial funding of $25 million. This financing transaction represents a portion of the financing authority granted in Case No. 2014-00210.

Q. PLEASE DESCRIBE THE IMPACT ON THE WEIGHTED AVERAGE COST OF LONG-TERM DEBT WITH REGARDS TO THE RECAPITALIZATION AND PRO FORMA DEBT ADJUSTMENTS.

A. The Company's weighted average cost of long-term debt inclusive of the pro forma debt adjustments is 5.41%, which is 47 basis points lower than the weighted average cost of long term debt of 5.98% filed in Case No. 2013-00197, which was subsequently withdrawn per the settlement in Case No. 2012-00578.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	)	
A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	Case No. 2014-00396
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

DIRECT TESTIMONY OF

JOHN A ROGNESS

ON BEHALF OF KENTUCKY POWER COMPANY

SECTION III

VOLUME 3 OF 4

December 23, 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For:	**)**	
(1) A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	**Case No. 2014-00396**
Environmental Compliance Plan; (3) An Order	**)**	
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

JOHN A. ROGNESS III

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, John A Rogness III, being duly sworn, deposes and says he is the Director Regulatory Services for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

John A Rogness III

COMMONWEALTH OF KENTUCKY	)	
	)	Case No. 2014-00396
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John A Rogness III, this the 16th day of December, 2014.

Judy K Rosquist 481393
Notary Public

My Commission Expires: January 23, 2017

DIRECT TESTIMONY OF
JOHN A ROGNESS III, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
JOHN A. ROGNESS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A: My name is John A. Rogness III. My position is Director, Regulatory Services for Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40601.

II. BACKGROUND

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I received a Bachelor of Science in Economics from the University of Chattanooga in 1980, a Master of Science in Economics from Vanderbilt University in 1984 and a Ph.D. in Economics from the University of Kentucky in 1991.

In January 1990, I began working in the Kentucky Office of Financial Management and Economic Analysis. From July 1991 – September 1998, I served as an Economist with the Kentucky Public Service Commission (Commission). From September 1998 – July 2010, I served as Manager of the Management Audit Branch at the Commission. From August 2010 – September 2012, I served as the Director of the Financial Analysis Division at the Commission. From October 2012 – March 2014, I served as the Director, Energy Generation, Transmission and Distribution at the Department for Energy

Development and Independence in Kentucky's Energy and Environment Cabinet. On March 17, 2014, I began my duties as Director of Regulatory Services for Kentucky Power.

Q: WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF REGULATORY SERVICES?

A: As Director of Kentucky Power's Regulatory Services, I am responsible for the rate and regulatory matters of Kentucky Power. This includes the preparation and coordination of the Company's testimony and exhibits in rate cases and any other formal filings before this Commission and federal regulatory bodies. In addition, I am responsible for assuring the proper application of the Company's rates and tariffs in all classifications of business.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A: Yes. I testified before the Commission at the hearing in Case No. 2014-00225. Also, I submitted testimony in Case No. 2014-00336.

III. PURPOSE OF TESTIMONY

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

A: The purpose of my testimony is two-fold. First, I present certain revenue and operating expense adjustments to test year values. Second, I describe the nature and bases for certain changes to the Company's filed tariffs.

Q: **ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?**

A: Yes. I identify the exhibits that I am sponsoring throughout my testimony, and list them below:

- Exhibit JAR-1: Rockport Extension Capacity Charge Development

- Exhibit JAR-2: Capacity Charge Tariff Revenues
- Exhibit JAR-3: Over/(Under) Recovery of Fuel Costs
- Exhibit JAR-4: Analysis and Monthly Breakdown of Non-Recurring Charges
- Exhibit JAR-5: Analysis of Non-Recurring Charges at Proposed Rates
- Exhibit JAR-6: Monthly Non-Recurring Charge Test Year Revenue at Current Rates
- Exhibit JAR-7: Monthly Non-Recurring Charge Revenues at Proposed Rates
- Exhibit JAR-8: Proposed Tariff Sheets
- Exhibit JAR-9: Strike Through Tariff Sheets

Q: **WERE THESE SCHEDULES AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?**

A: Yes.

IV. <u>REVENUE AND OPERATING EXPENSE ADJUSTMENTS</u>

Q: WHY ARE REVENUE AND OPERATING EXPENSE ADJUSTMENTS NECESSARY?

A: Adjustments are necessary because certain known and measurable adjustments to the data developed in the test year ending September 30, 2014 must be made to more accurately represent the Company's future revenue requirement.

Q: WOULD YOU PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING?

A: Yes. The details of the revenue and operating expense adjustments set forth on various pages of Section V, Exhibit 2. Specifically, I am sponsoring the following adjustments:

	Adjustment	**Exhibit 2, Page No.**
1.	Capacity Charge Revenues Adjustment (Rockport)	W1
2.	Miscellaneous Service Charges	W6
3.	Fuel Under (Over) Recovery Revenues	W7
4.	O&M Expense Interest on Customer Deposits	W11
5.	Amortization Out of Period PSC Mandated Consultant Cost	W12
6.	Rate Case Expense	W15
7.	Postage Rate Increase Adjustment	W16
8.	Eliminate Advertising Expense	W17
9.	Annualization of Lease Cost	W18
10.	Annualization of Property Tax Expense	W44
11.	Annualization of PSC Maintenance Assessment	W45
12.	Coal Stock Adjustment – Mitchell Plant	W54
13.	Coal Stock Adjustment – Big Sandy Plant	W55

Interest Expense Associated with Customer Deposits
(Section V, Exhibit 2, W11)

Q. **EXPLAIN THE ADJUSTMENT FOR INTEREST EXPENSE ASSOCIATED WITH CUSTOMER DEPOSITS.**

A. Customer deposits have been included in this case as a reduction to the Company's Rate Base. This recognizes that customer deposits, similar to customer advances for construction, are a source of funds to the Company.

Unlike customer advances for construction however, interest is paid to customers for customer deposits. In the past, interest was paid at a rate of 6% per annum, however due to new legislation passed in 2012, the new rate beginning January 1, 2015 is unchanged from 2014. The new rate is 0.12% per annum. Consistent with the treatment of interest allowed by the Commission in past cases, an adjustment has been made to annualize these test year expenses to the current rate of 0.12% per year by an adjustment of $2,422.

Capacity Charge Revenues Adjustment
(Rockport Unit Power Agreement)
(Section V, Exhibit 2, W1)

Q. WHAT IS THE CAPACITY CHARGE?

A. In accordance with the Stipulation and Settlement Agreement dated October 20, 2004, in Case No. 2004-00420, the Capacity Charge is designed to enable recovery from each class of customers for the supplemental annual payments tied into the Rockport Unit Power Agreement. The Commission authorized Kentucky Power to collect $6.2 million annually through 2021, and $5,792,329 in 2022 through the Capacity Charge.

Q. WILL THERE BE ANY CHANGES TO THE CAPACITY CHARGE RATES?

A. Yes. In accordance to Section (1)(d)(iii) of the Stipulation and Settlement Agreement, Kentucky Power will develop, and other Parties will not oppose, a new tariff that will allow the Company to receive the additional Capacity Charge revenue. Kentucky Power is seeking to change the Capacity Charge rates to

$0.000659 per kWh for I.G.S. customers, and $0.001182 per kWh for all other customer classes. The I.G.S. customer class (discussed more fully below) is the result of combining the Q.P. and C.I.P.-T.O.D. customer classes pursuant to the Stipulation and Settlement Agreement and subsequent Commission Order in Case No. 2012-00578. Please see Exhibit JAR-1 for the calculations of the new Capacity Charge rates.

Q. IS THE COMPANY MAKING ANY OTHER PROPOSALS THAT WILL IMPACT THE CAPACITY CHARGE?

A. Yes. As can be seen in Section V, Exhibit 2, W1, the Company has not collected the full Capacity Charge amount authorized by the Commission. In order to collect the authorized annual amount, Kentucky Power is proposing an annual true-up. This will allow any over/under recovery from the previous 12 month period, to be collected in the following 12 month period in addition to the Commission's authorized annual amount. Please see Exhibit JAR-8, Original Tariff Sheet No. 28-2 for the proposed formula to calculate the Capacity Charge rates with the annual true-up.

Amortization of Out of Period Commission Mandated Consultant Cost & Elimination of Commission Mandated Consultant Expense during Test Year (Section V, Exhibit 2, W12)

Q. PLEASE EXPLAIN THE COMMISSION MANDATED CONSULTANT COST ADJUSTMENT.

A. When the Commission requires additional technical expertise, it hires a consultant to assist in determining whether certain technical portions of the case are just and reasonable. The Company is required to compensate the consultant and is then allowed to request reimbursement in its next filed rate procedure. Kentucky Power did not pay any consultants fees during the test year. However, Kentucky Power has compensated consultants for the Commission in three such cases since its last base case as described below:

- In Case No. 2011-00295, The Application of Kentucky Power Company for a Certificate of Public Convenience and Necessity to Construct a 138kV Transmission Line and associated Facilities in Breathitt, Knott and Perry Counties, Kentucky (Bonnyman-Soft Shell Line), Accion Group Inc was hired at a cost of $26,440;
- In Case No, 2011-00401, The Application of Kentucky Power Company for Approval of its 2011 Environmental Compliance Plan, For Approval of its Amended Environmental Cost Recovery Surcharge Tariff, and for the Grant of a Certificate of Public Convenience and Necessity for the Construction and Acquisition of Related Facilities, Vantage Energy Consulting LLC was hired at a cost of $119,338; and
- In Case No. 2012-00578, The Application of Kentucky Power Company in Connection with the Transfer of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Certain Related Relief, Vantage Energy Consulting LLC was again hired at a cost of $108,814.

The total amounts for the three consultants of $254,592 should be amortized over three years at a rate of $84,864 per year. A three-year amortization will assure that the cost of the consultants are being borne by those customers that received the benefit of their involvement in the most recent rate proceeding, rather than spreading it over a longer period.

Miscellaneous Service Charges
(Section V, Exhibit 2, W16)

Q. WHAT ARE THE MISCELLANEOUS SERVICE CHARGE ADJUSTMENTS?

A. Kentucky Power charges its customers for services such as Reconnects, Collection Trips, Bad Checks and Meter Test charges. As I will discuss later, the Company is proposing to increase the rates charged for such services to more closely match the cost to the Company. This adjustment annualizes test year revenues based upon the proposed new rates. The impact is to increase Kentucky Power revenues by $251,903. Also see Exhibits JAR-4 and 5.

Annualization of PSC Maintenance Assessment
(Section V, Exhibit 2, W45)

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT IN CONNECTION WITH THE KENTUCKY PSC ASSESSMENT FEE EXPENSE?

A. Yes. The Company received an invoice from the Commonwealth of Kentucky in June 2014 in the amount of $1,069,553 for the Kentucky PSC Assessment fee. During the test year the Company recorded $977,073 in Kentucky PSC assessment fees. The Company's proposed adjustment is to increase the Taxes Other Than Income Taxes expense by the difference between the test year amount and the June 2014 assessment, or $92,475.

<u>Rate Case Expense Adjustment</u>
<u>(Section V, Exhibit 2, W15)</u>

Q. WHAT IS THE RATE CASE EXPENSE ADJUSTMENT?

A. The Company is allowed to recover the costs of preparation and execution of its rate case proceeding, including consulting and legal expenses. The Company has received invoices totaling $28,630 as of September 30, 2014. However, the Company estimates a total rate case expense of $860,000. The difference between actual and estimated expenses should be amortized over three years at the rate of $258,037 per year.

<u>Postage Rate Increase Adjustment</u>
<u>(Section V, Exhibit 2, W16)</u>

Q. WHAT IS THE POSTAGE RATE INCREASE ADJUSTMENT?

A. The test year adjustment for postage expense annualizes the United States Postal Service 5.42% across-the-board increase that went into effect on January 6, 2014. To reflect this increased cost, the number of bills, notices, letters, etc. mailed by the Company from October 1, 2013 through January 26, 2014, 610,938, was multiplied by the postage rate increase of 5.42% or $0.02 per mailing, resulting in an increase to Operation and Maintenance (O&M) Expenses of $12,219.

<u>Eliminate Advertising Expense</u>
<u>(Section V, Exhibit 2, W17)</u>

Q. WHY ARE ADVERTISING EXPENSES BEING ELIMINATED?

A. Pursuant to 807 KAR 5:016 Section 4(1) those expenses that were for promotional and institutional advertising must be removed from the test year. A review was made of advertising expenses recorded during the test year and a total of $30,610 is being eliminated from O&M Expenses.

Annualization of Lease Costs
(Section V, Exhibit 2, W18)

Q. WHY ARE LEASE COSTS ANNUALIZED?

A. This adjustment annualizes the current level of lease costs based on September 2014 lease rental expenses and compares that amount to the amount of least costs incurred during the test year. The adjustment increases the jurisdictional O&M Expense by $72,974.

Annualization of Property Tax Expense
(Section V, Exhibit 2, W44)

Q. WHY ARE PROPERTY TAX EXPENSES ANNUALIZED?

A. The Transmission and Distribution property tax expense reflected in the test year is based upon the actual property tax amounts collected during the test year. The Company estimated the property tax expense on a going forward basis using the most recent assessable property value (from December 31, 2013) and the most recent property tax rates. This adjustment increases property taxes by a jurisdictional amount of $314,531 to reflect increased property tax expense going forward. The Generation portion of property tax expense is included in adjustments related to recovery of Big Sandy Plant and Mitchell Plant costs supported by Company Witness Yoder.

Fuel Under/(Over) Recovery Revenues
(Section V, Exhibit 2, W7)

Q. PLEASE EXPLAIN THE ADJUSTMENTS PROPOSED IN CONNECTION WITH THE OVER/(UNDER) RECOVERY OF FUEL COSTS.

A. As Exhibit JAR-3 demonstrates, the total test year level of jurisdictional fuel costs was $214,069,635. The total test year level of jurisdictional fuel revenues were $204,806,948, or a difference of ($14,561,463). In order to properly design rates so that the appropriate level of revenue is recovered from the Kentucky customers, test year revenues should be decreased by $5,298,776. This adjustment trues up the fuel clause revenues with the actual fuel clause expenses. If this adjustment were not made, the rates to be designed would assume that each year the tariffs are in effect the Company would over-recover its fuel costs by $5,298,776.

Q. ARE THERE ANY OTHER ADJUSTMENTS RELATED TO THE OVER OR UNDER-RECOVERY OF FUEL COSTS?

A. Yes. There is an associated deferred tax adjustment in the amount of ($1,854,572) required with the fuel cost adjustment. The Company has made this adjustment in its prior rate cases and the Commission has accepted the adjustment. Details of this adjustment are supported by Witness Bartsch.

Coal Stock Adjustments
(Section V, Exhibit 2, W54 & W55)

Q. WHY ARE COAL STOCK ADJUSTMENTS NECESSARY?

A. The Coal Stock Adjustment adjusts the coal pile investment at the Big Sandy and Mitchell Plants to the supply level allowed for recovery. The supply level requested at each plant is based on many factors, including the means of transportation to the plant and the location of the supplier in relation to the plant. For Big Sandy and Mitchell Plants the necessary supply level is 30 days and 45 days, respectively. The effect of this adjustment is to reduce Kentucky Power's

Materials and Supplies – Fuel Stock working capital by $664,080 for Mitchell. In accordance with the Stipulation and Settlement Agreement the Commission's October 7, 2013 Order in Case No. 2012-00578, the coal related assets and associated expenses for Big Sandy have been removed from rate base in their entirety. The treatment of the coal-related assets and expenses for Big Sandy is addressed in the testimony of Company Witness Wohnhas.

V. TARIFF REVISIONS

Q. IS THE COMPANY PROPOSING ANY ADDITIONS OR CHANGES TO THE COMPANY'S TARIFFS CURRENTLY ON FILE WITH THE COMMISSION?

A. Yes. The revisions are indicated in the right-hand margin of each tariff sheet attached in Section III, Exhibits JAR-8 and JAR-9. Some of the changes are minor text changes and are self-explanatory. I will address the following major tariff changes in my testimony:

- tariff eliminations;
- new tariffs and charges;
- changes to the Company's current terms and conditions of service;
- changes to the Company's schedule of special or non-recurring charges;
- changes to Company's current bill format; and
- changes to the Company's current tariffs.

Tariff Eliminations

Q: IS THE COMPANY PROPOSING ELIMINATION OF ANY TARIFFS IN THIS PROCEEDING?

A: Yes, the Company proposes to eliminate four tariffs:

- Tariff Q.P., Quantity Power (Tariff Sheet Nos. 10-1 thru 10-4), is being eliminated in accordance with the Stipulation and Settlement Agreement and subsequent Commission Order in Case No. 2012-00578;
- Tariff C.I.P.-T.O.D., Commercial and Industrial Power – Time of Day (Tariff Sheets 11-1 thru 11-3), is being eliminated in accordance with the Stipulation and Settlement Agreement and subsequent Commission Order in Case No. 2012-00578;
- Rider E.C.S.-C.&E., Emergency Curtailable Service – Capacity & Energy (Tariff Sheet Nos. 24-1 thru 24-6), is being eliminated because it expired May 31, 2012;
- Rider E.P.C.S., Energy Price Curtailable Service Rider (Tariff Sheet Nos. 25-1 thru 25-3), is being eliminated because there are no current customers; and
- Tariff R.T.P., Experimental Real Time Pricing (Tariff Sheet Nos. 30-1 thru 30-4) is an experimental tariff, with no current customers. It was effectively terminated by the Commission's Order dated December 20, 2012 in Case No. 2012-00226. As such, the Company is eliminating the tariff.

New Tariffs And Charges

Q: IS THE COMPANY PROPOSING ANY NEW TARIFFS IN THIS PROCEEDING?

A: Yes, the Company is proposing several new tariffs and/or riders.

Q: PLEASE LIST THE NEW TARIFFS, RIDERS AND CHARGES THE COMPANY IS PROPOSING AND THE WITNESS WHO DISCUSSES THEM.

A: The Company is proposing the following new tariffs, riders and charges:

- Industrial General Service ("I.G.S.") Tariff, Tariff Sheet Nos. 10-1 thru 10-4;
- PJM Rider, Tariff Sheet Nos. 24-1 thru 24-3 – is supported by Company Witness Vaughn.
- Big Sandy Retirement Rider, B.S.R.R., Tariff Sheet No. 38-1 thru 38-2 – is supported by Company Witnesses Wohnhas and Yoder.
- Big Sandy 1 Operation Rider, B.S.1.O.R., Tariff Sheet No. 39-1 thru 39-2 – is supported by Company Witnesses Wohnhas and Vaughn.
- NERC Compliance and Cybersecurity Rider, Tariff Sheet 40-1 thru 40-3 – is supported by Company Witnesses Wohnhas and Stogran.
- Kentucky Economic Development Surcharge ("K.E.D.S.").

I discuss below the new I.G.S., Tariff Sheet No. 10-1 thru 10-4 and the Kentucky Economic Development Surcharge.

Q. TO WHICH CUSTOMER CLASS TARIFFS ARE THE NEW RIDERS, AND CHARGES APPLICABLE?

A. The PJM Rider, Big Sandy Retirement Rider, Big Sandy 1 Operation Rider, and the NERC Compliance and Cybersecurity Rider are applicable to the following Tariffs: R.S., R.S.-L.M.-T.O.D., R.S.-T O.D., Experimental R.S.-T.O.D.2, S.G.S.,

S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

The new Kentucky Economic Development Surcharge is applicable to the following Tariffs: R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., and S.L.

Q: PLEASE DESCRIBE THE I.G.S. TARIFF.

A: As a result of the Stipulation and Settlement Agreement and subsequent Commission Order in Case No. 2012-00578, the Company is combining the current Q.P. and C.I.P.-T.O.D. customer classes. To accomplish this, the Company has proposed eliminating those tariffs and replacing them with a new tariff for the combined customer classes, the Industrial General Service (I.G.S) Tariff. The new tariff is available to commercial and industrial customers whose contract capacity is no less than 1,000 kW. The rates, determined through a cost of service study, are supported in Company Witness Vaughn's testimony.

Q: PLEASE DESCRIBE THE KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

A: In order to help jump start economic development in its service territory, the Company is proposing the K.E.D.S. A monthly surcharge of $0.15 will be applied to each customer account for the purpose of funding economic development initiatives. As a part of its ongoing commitment toward fostering economic growth in the service territory, the Company proposes to match the funds raised through the surcharge with shareholder funds. Based upon test year end billing determinant data, the program will yield $307,507 from customers and with Company's matching funds will yield a total of $615,014 annually. The $0.15 per month charge has been added to each customer class tariff, except for outdoor lights.

Q: PLEASE EXPLAIN HOW THE FUNDS RAISED THROUGH THE K.E.D.S WILL BE UTILIZED TO FOSTER ECONOMIC DEVELOPMENT.

A: The Company is committed to pursuing economic development within the service territory. In December 2012, the Company commissioned InSite Consulting, LLC, a professional Site Location Consultant, to study a significant portion of the Kentucky Power service territory to determine gaps in economic development efforts. The study was completed in September, 2013 and the findings showed a significant absence of any organized regional or local economic development effort in the Company's service territory. Based on the recommendations of the consultants' report, focus is necessary in the following four strategic areas, each of which will require additional funding:

- Specification Building Seed Money – Currently, there are no available specification buildings located at three of the four existing industrial parks. The authorities responsible for the industrial parks without specification buildings are in the planning stages for such a building, but seed money is needed for design and planning activities as well as local matching dollars for anticipated grant funds.
- Infrastructure Improvements – The InSite report provided an inventory of recommended infrastructure improvements for each of the key industrial

properties in the Company's service territory. Each property has infrastructure deficiencies that, until they are remedied, make the property not competitive. Additional funding is necessary for design and construction activities to make these properties competitive.

- Master Plan Updates – Many of the key properties identified in the InSite report do not have an existing master plan. If a master plan does exist, it needs to be modified to meet the standards of a nationally competitive property prospect. Additional funding would be used to create, update, and implement property master plans that will facilitate the proper use of each of the identified industrial parks.
- Site Marketing – Currently, no organization is funded to market any existing industrial properties. Industrial authorities are in place to manage most of the properties, but they lack the necessary funding to improve or market the properties. Additional funding would be used to market these properties to site consultants and target industries.

InSite has also completed two additional studies. InSite's Phase II study narrowed down the list of possible properties and identified the improvements necessary to make key industrial properties market ready. The Phase II study prioritized the infrastructure investment projects based on which would provide the best return on investment for the Company's service territory. InSite's Phase III study is focused on providing assistance the owners of the top two properties identified in Phase II. The Phase III study is providing assistance to these owners in documenting all due diligence items required to market these properties effectively, including which items need to be addressed and the associated cost.

Working with InSite has provided the Company with detailed, specific tasks. Investing resources to implement these tasks will result in a service territory that is able to participate effectively in the competitive economic development arena. The Company will use K.E.D.S. funds along with assistance from local governments, state government, and other private industries to implement the InSite studies' recommendations.

Q: PLEASE IDENTIFY THE BENEFITS KENTUCKY POWER'S CUSTOMERS WILL RECEIVE FROM SUCCESSFUL ECONOMIC DEVELOPMENT ACTIVITIES?

A: Broadly speaking, there are multiple benefits to the service territory from the economic development that will result from implementing this program. Increased economic activity and additional jobs will benefit those families directly employed. The additional money that is spent within the service territory will also spur additional economic activity which will support additional jobs. The increased economic activity will also strengthen communities' tax base, which will in turn help to support schools and other local government provided services. In addition, the Company has seen both its load and customer base erode slowly over the last several years, especially as mining activity has slowed down. The Company, by strengthening communities' ability to grow the service territory economy will grow its load and its customer base. Everything else being equal, this will allow the Company to spread its costs over a greater number of kilowatt hours and customers and keep the cost to individual customers as low as possible.

Specifically, funds can be used to help support the creation and implementation of Master Plans for industrial sites, site infrastructure development, and the planning and design of buildings that could be used by prospective businesses. Having industrial sites and buildings ready for occupancy is crucial to attracting new businesses. Finally, once sites are ready for occupancy, marketing the prospective sites effectively is an important next step. Equally important is enhancing the training and resources of local economic development organization personnel. These are all necessary activities that are not being accomplished currently. The additional funding that the surcharge will provide, along with the Company's matching funds and leadership, will help communities within the service territory be more competitive in attracting prospective employers and creating jobs.

Q: IS THE COMPANY PURSUING ANY OTHER ECONOMIC DEVELOPMENT PROGRAMS WITHIN ITS SERVICE TERRITORY?

A: Yes. Broadly, there are several initiatives.

- Kentucky Power has hired a Manager – External Affairs in June 2012 whose primary responsibility is working in conjunction with local governments and economic development organizations in the Company's service territory to find and bring new businesses to the service territory that will help create jobs and sustained economic growth.

- On September 18, 2014, the Company submitted an Economic Development Rider tariff for Commission approval in Case No. 2014-00336. That tariff is designed to offer a temporary declining discount to the demand charge for new industrial and commercial load of at least 500 kW. The Commission has not issued a final Order in that case. The proposed Tariff E.D.R. is included as Tariff Sheet Nos. 37-1 to 37-5.

- As a result of the Settlement Agreement and subsequent Commission Order in Case No. 2012-00578 dated October 13, 1013, the Company is contributing $200,000 per year through 2018 toward economic development in Lawrence County and the surrounding contiguous counties. The Company is also providing $33,000 per year designated for job training for five years to two technical colleges in the Kentucky Community and Technical College System, Ashland Community and Technical College and Big Sandy Community and Technical College.
- Kentucky Power also is an active participant in Shaping Our Appalachian Region (SOAR). This initiative was created by Gov. Steve Beshear and Rep. Hal Rogers, R-Ky. to improve the economy and quality of life in Eastern Kentucky. Also, the Manager – External Affairs serves as Co-Chair for the Business Recruitment and Expansion Committee for SOAR.

Changes to the Company's Terms and Conditions of Service

Q. ARE THERE ANY CHANGES TO THE COMPANY'S CURRENT TERMS AND CONDITIONS OF SERVICE BEING PROPOSED IN THIS PROCEEDING?

A. Yes. Changes are being proposed to Kentucky Power's Terms and Conditions of Service on Tariff Sheet Nos. 2-1, 2-2, 2-3, 2-7, 2-9, and 2-10 as described below:

- Tariff Sheet No. 2-1, paragraph 1, was revised to add the location of the on-line tariff.
- On Tariff Sheet No. 2-2, the Criteria for Waiver of Deposit Requirement, Paragraph 4B, was revised for clarification. The language was modified to define what the Company considers to be "satisfactory payment criteria." If the customer complies with the satisfactory payment criteria the Company may waive the deposit requirements.
- Tariff Sheet No. 2-3, paragraph 4D, Additional or Supplemental Deposit Requirement was modified to allow the Company the ability to impose additional deposit requirements for residential and non-residential customers who fail to maintain a satisfactory payment criteria or a payment history. It will also allow the Company to require an additional or supplemental deposit if a non-residential customer's credit rating falls to specific levels as reported by various national credit reporting agencies, such as below a "C" level at Value Line, a "BB+" level at Standard & Poor's, a "BB+" level at Fitch, or a "Ba3" level at Moody's. The modification reflects the fact that the current tariff language uses only the

Value Line criteria yet because not all customers are listed in Value Line, this was not adequate to assure customer ratings.

- Tariff Sheet No. 2-8, paragraph 14, Monitoring Usage, was clarified to state that the Company monitors each customer's usage at least quarterly.
- Tariff Sheet No. 2-9, paragraph 16 was modified to clarify that individual residences are to be served by single phase service under the applicable residential service tariff.
- On Tariff Sheet No. 2-9, paragraph 17, Denial or Discontinuance of Service, the language has been revised to define an applicant as a customer in conformity with the Commission's definition of a customer.
- Tariff Sheet No. 2-10, paragraph 19A, was modified to clarify that the third line should be labeled "3. Reconnect for nonpayment when a "Call Out" is required prior to 10:00 PM". Also, clarifying language was added "Reconnection for nonpayment will not be made when a "Call Out" after 10 pm is required."; and
- Tariff Sheet No. 2-10, paragraphs 19C Returned Check Charges and 19D Meter Test Charges have been revised so the rates more closely match current costs.

<u>Changes to the Bill Format</u>

Q. ARE THERE ANY CHANGES TO THE COMPANY'S CURRENT BILL FORMAT BEING PROPOSED IN THIS PROCEEDING?

A. Yes. The Company is proposing to add the following line items to customer bills:

- Kentucky Economic Development Surcharge

- Big Sandy 1 Operation Rider
- P.J.M. Rider
- NERC Compliance and Cybersecurity Rider
- Big Sandy Retirement Rider

Q: IS THE COMPANY PROPOSING ANY FURTHER CHANGES TO THE BILL FORMAT?

A: No, not in this proceeding. The Company proposed a change to its bill format applicable to residential service tariffs for an optional non-regulated home warranty service. This tariff filing is the subject of a separate Commission proceeding, Case No. 2014-00420. Once the Commission has issued its final Order in that case, the Company will make any necessary amendments to the tariff pursuant to the Commission's Order.

<u>Changes to the Company's Schedule of Special or Nonrecurring Charges</u>

Q: WHAT ARE SPECIAL OR NONRECURRING CHARGES?

A: Special or Nonrecurring charges are charges to customers due to a specific request for certain types of services for which, when the activity is completed, no additional charges will be incurred. Such charges are intended to be limited in nature and to recover the specific cost of the activity.

Q: DOES THE COMPANY HAVE ANY SPECIAL CHARGES CURRENTLY IN ITS TERMS AND CONDITIONS OF SERVICE?

A: Yes. The Company currently has four categories of Special Charges. They are: (1) reconnect for nonpayment charge, (2) termination or field trip charge, (3) returned check charge, and (4) meter test charge. The existing Special Charges were last modified in Case No. 2005-00431. The Company sought to modify the Special Charges in the last base rate case, Case No. 2009-00459, but the Special Charges were not changed as part of the Settlement Agreement resolving that case.

Q: DOES THE COMPANY HAVE DIFFERENT CHARGES WITHIN THE RECONNECT FOR NONPAYMENT CATEGORY?

A: Yes. The Company has the following four categories of reconnect for nonpayment:

1. Reconnect for non-payment during regular business hours;
2. Reconnect for non-payment at the end of the day (No "Call Out" required);
3. Reconnect for non-payment when a "Call-Out" is required prior to 10:00 PM; and
4. Reconnect for non-payment on a Sunday and Holiday.

Q: WHY DOES THE COMPANY HAVE FOUR DIFFERENT RECONNECT FOR NONPAYMENT CHARGES?

A: The four different charges reflect the unique costs associated with each of the four types of reconnections. For example, when the Company reconnects a customer after normal business hours, an employee is "called out" and the Company is obligated to pay that employee time and half for a minimum of two hours. When the Company reconnects a customer on a Sunday or a Holiday, an employee is called out and the Company is obligated to pay the employee double time for a minimum of two hours. Also, the Company incurs different costs depending upon the time of day (or night) the work is performed. The intent of the Special

Charges is to assign the cost incurred by the Company to perform the specific activity to the customer who required the Company to incur those costs. The customer has the ability to decide what charge to be incurred.

Q: HOW WERE THE AMOUNTS OF THE DIFFERENT SPECIAL CHARGES SERVICE RECONNECTION DETERMINED?

A: The methodology used to determine the Special Charges is the same methodology that has been used in prior rate cases. Using data and information supplied by the field employees and their supervisors, the average time to perform the different activities was calculated. The Company then aggregated the total labor costs, transportation costs, fringe benefit costs and any other associated cost incurred to arrive at the total cost to perform each of the different activities listed on Exhibit JAR-5. Where it differed, the Company also calculated the costs incurred based upon the amount of time the Company is required to pay the employee for performing a service. For example, on reconnections requiring a call out at night, on weekends, or on holidays, the minimum hours that can be logged by the worker is two hours. Accordingly, for the same reconnection, the cost varies from $21.29 during regular hours, $30.91 when it goes into overtime, $95.46 for a weekday call-out, and $124.15 for a Sunday or holiday call-out, which requires payment of double time.

Q: ARE THERE ADDITIONAL CHANGES TO THE COMPANY'S RECONNECT POLICY?

A: Yes. The Company is revising the tariff for reconnection after hours with a Call Out. For reasons of personnel safety, the Company will no longer call out personnel to reconnect customers after 10 PM. Work orders generated after 10 PM will be handled at the beginning of the next business day. Even though the Company will no longer call out personnel after 10 PM, it will still be providing reconnections within the requirements of 807 KAR 5:006, Section 14(4).

Q: ARE THERE CHANGES TO OTHER SPECIAL CHARGES?

A: Yes. The methodology used to determine the Special Charges is the same methodology used in prior rate cases. See Exhibit JAR-5 for an analysis of the various labor costs, transportation costs, fringe benefit and other associated costs incurred by the company for the following Special Charges:

- Termination or Field Trip Charge. When the Company makes a special trip to the customer's premises to perform a disconnect for non-payment, the Company incurs a cost of $12.99. The Company is proposing a charge of $13.00.
- Meter Test Charge. Upon written request by the customer, the Company will test the meter for accuracy. The Company incurs a cost of $48.25 for each test and is proposing a charge of $48.00.
- Bad Check Charge. When a customer pays the monthly bill with a check that is subsequently returned, there is labor involved in the processing, as well as assessed bank fees. The cost to the Company of a bad check is $18.71 and is proposing a charge of $18.00.

Q: ARE THERE ANY NEW SPECIAL CHARGES?

A: Yes. The Company is proposing a new Special Charge on Tariff Sheet No. 2-10 paragraph 19B Meter Reading Check. There are instances in which the customer wants the Company to read the meter a second time. Currently, the Company reads all its meters electronically. When the Company makes a special trip to a customer's premise to perform a manual visual meter read, the Company incurs costs in the same manner as in the performance of a service reconnect during regular business hours, i.e., $21.29. The Company is proposing a Meter Reading Check charge of $21.00. See Exhibit JAR-5 for an analysis of the various labor costs, transportation costs, fringe benefit and other associated costs incurred by the Company for a meter reading check.

Q: WHAT IS THE ADDITIONAL ANNUAL REVENUE THE COMPANY WOULD ANTICIPATE BY INCREASING THE SPECIAL CHARGES?

A: If the proposed changes to all Special Charges were in effect for the twelve months ending September 31, 2014, and the number of transactions for each activity remained the same, the total increase in the Company's Special Charges revenue would have been $251,903. A breakdown of this increase in Special Charges revenue by type of charge and customer class is shown on Exhibits JAR-5 – JAR-7.

<u>Changes to the Company's Current Tariffs</u>

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO EXISTING TARIFFS?

A. Yes. In addition to the changes identified above and the changes relating to rate updates, the Company is proposing to update numerous tariffs. These changes are described below.

<u>Residential Service Tariffs (Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D.2)</u>

Q. IS KENTUCKY POWER PROPOSING ANY CHANGES TO THE EXISTING RESIDENTIAL SERVICE TARIFFS?

A. Yes. The Company is proposing to make the following changes:

1. Add language to note that Volunteer Fire Departments may take service under residential Tariff R.S. Tariff Sheet No. 6-2.
2. Under Special Terms and Conditions, replace language to explain availability as follows: "This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service" on Tariff R.S. Tariff Sheet No. 6-4, Tariff R.S.-L.M.-T.O.D. Tariff Sheet No. 6-7, Tariff R.S.-T.O.D. Tariff Sheet No. 10 and Tariff R.S.-T.O.D. 2 Tariff Sheet No. 6-13 .
3. Add language to clarify that extensions for service "of up to 150 feet for a mobile home are provided without charge" on Tariff R.S. Tariff Sheet No. 6-4.

Small General Service Tariffs (Tariffs S.G.S. and S.G.S.-T.O.D.)

Q. IS KENTUCKY POWER PROPOSING ANY CHANGES TO THE EXISTING SMALL GENERAL SERVICE TARIFFS?

A. Yes. The Company is proposing to add language to Tariff S.G.S. Tariff Sheet No. 7-1 and Tariff S.G.S.-T.O.D. Tariff Sheet No. 7-4 to limit this tariff to metered customers being served at a secondary distribution voltage because the rate was designed for secondary service. Under Availability of Service, the Company has added the following grandfather clause "Customers not meeting the requirements for availability under this tariff will only be permitted to continue service under this tariff at the premise occupied for continuous service beginning no later than January 22, 2015."

M.G.S. Tariff - Medium General Service

Q: ARE THERE ANY PROPOSED CHANGES TO THE M.G.S. TARIFF?

A: Yes. At Tariff Sheet No. 8-1 under Availability of Service, the Company is proposing to add the following language to clarify that "Customers receiving service on or before January 22, 2015 at a secondary voltage and with average monthly demand below 10 kw will be served under the S.G.S. tariff". Also on Tariff Sheet 8-4, under Term of Contract, the Company is modifying the contract terms such that contracts may be required of any customer, regardless of the level of normal maximum demand.

Quantity Power C.I.P.-T.O.D. Combined Tariff

Q: ARE THERE ANY PROPOSED CHANGES TO THE TERMS AND CONDITIONS FOR THE Q.P. and C.I.P.-T.O.D TARIFF?

A: Yes. Per the Stipulation and Settlement Agreement and the Commission's Order in Case No. 2012-00578, the Company eliminated Tariffs Q.P. and C.I.P.-T.O.D. and replaced them with a new Tariff Industrial General Service (I.G.S.). Please see Exhibits JAR-8 and JAR-9 for the proposed Tariff I.G.S.

Tariff C.S.-I.R.P. – Contract Services – Interruptible Power

Q: ARE THERE ANY PROPOSED CHANGES TO THE TERMS AND CONDITIONS FOR THE C.S.-I.R.P TARIFF?

A: Yes. Per the Stipulation and Settlement Agreement and the Commission's Order in Case No. 2012-00578, on Tariff Sheet No. 12-1, the Company has increased the total contract capacity for all customers served under Tariff C.S.-I.R.P. from 60,000 kW to 75,000 kW. In addition, under Rate, language has been added to clarify that "Credits under this Tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's rules as capacity for the purpose of the Company's FRR obligation."

C.A.T.V. Tariff – Cable Television Pole Attachment

Q: ARE THERE ANY PROPOSED CHANGES TO THE C.A.T.V. TARIFF?

A: Yes. At Tariff Sheet No. 16-1 under Availability of Service, the Company has clarified the definition of "attachment" to mean "physical connection of (a) a messenger strand supporting the wires, cables or stand-mounted associated facilities and equipment of a cable system or (b) service drops affixed to the pole and located more than one vertical foot away from the point at which the messenger strand is attached to the pole (but not a strand originating or mid-span service drop) or (c) service drops located on a dedicated service, drop or lift pole.

An attachment shall consume no more than one foot (1') of vertical space on any distribution pole owned by the Company." In addition, the Company has clarified the applicability of the rates to be applied as "attachments per year" and defined two and three user poles. On Tariff Sheet No. 16-4 under Charges and Fees, the Company is proposing "an annual charge per attachments set forth on Sheet 16-1" rather than semi-annually. Also under Advance Billing, when a payment date is not specified on an invoice, the Company is extending the time to make the payment from 15 to 30 days.

<u>Tariff O.L. – Outdoor Lighting</u>

Q: ARE THERE ANY PROPOSED CHANGES TO THE TERMS AND CONDITIONS FOR THE OUTDOOR LIGHTING TARIFF?

A: The Company is proposing to clarify the Terms of Initial Service on Sheet No. 14-4 by adding the following language, "If early termination is requested, the customer will be billed for the remainder of the 12 month period." Consistent with cost-causation principles, it is important that the cost for installing a new outdoor light is paid by the customer that requested that installation instead of the Company's other customers.

<u>Tariffs COGEN/SPP I and COGEN/SPP II</u>

Q: PLEASE DESCRIBE THE ADDITIONS TO THE COGEN/SPP TARIFFS.

A: Tariff Sheet Nos. 17-1 and 18-1, Tariff COGEN/SPP I and II, respectively, under Monthly Metering Charge Option 1, are being revised to state "Option 1 – Not Applicable." The Company uses AMR meters that no longer require a detent to prevent reverse rotation, so the prior language is obsolete.

On Tariff Sheet No. 17-3 under Capacity Credit B.(2), the calculation of the on-peak metered average capacity is being modified to correct an arithmetic error in the current tariff. The revised tariff calculates the on-peak metered average capacity by dividing the on-peak kWh delivered to the Company or produced by COGEN/SPP facilities divided by 305 instead of 327 as in the current tariff.

On Tariff Sheet No. 18-3 under Capacity Credit B.(2), the calculation of the on-peak metered average capacity is being modified to correct an arithmetic error in the current tariff. The revised tariff calculates the on-peak metered average capacity by dividing the on-peak kWh delivered to the Company or produced by COGEN/SPP facilities divided by 305 instead of 730 as in the current tariff. Because there are no customers on this tariff, the error in the current tariff has had no adverse effect.

Tariff S.S.C. – System Sales Clause

Q. IS THE COMPANY PROPOSING CHANGES TO TARIFF S.S.C.?

A. Yes. Company Witness Wohnhas addresses revisions to Kentucky Power's Tariff S.S.C., System Sales Clause, Tariff Sheet Nos. 19-1 and 19-2.

Tariff T.S. – Temporary Service

Q. IS THE COMPANY PROPOSING CHANGES TO TARIFF T.S.?

A. Yes. On Tariff Sheet No. 21-1 the Company is clarifying Availability of Service to state that "Residential customers will be supplied with 100 amp service. All other customer classes will be supplied at voltage levels applicable to the class of business." In addition, The Company is clarifying the Term of temporary service to be more in line with the time necessary to complete a construction project. The Company will install the temporary service for an initial period of 180 days and may extend the service for an additional 90 days.

Tariff N.U.G. – Non-Utility Generator

Q. WHAT REVISIONS BEING PROPOSED TO THE COMPANY'S EXISTING TARIFF N.U.G.?

A. Because of the differences in those customers that would request Tariff N.U.G., and the customer-specific terms that may be necessary during Startup, a contract is required for each customer under the Startup Power Service section. On Tariff Sheet No. 26-2, the Company has removed the Monthly Transmission and Distribution Rates under that section to accommodate the differences and will now include those rates in the customer's contract, similar to the way generation rates are treated.

Tariff N.M.S. – Net Metering Service

Q. WHAT REVISIONS BEING PROPOSED TO THE COMPANY'S EXISTING TARIFF N.M.S.?

A. On Tariff Sheet Nos. 27-9 and 27-15 of Tariff N.M.S. the Company designee is being changed to reference the Distributed Generation Coordinator and not a specific individual so that the tariff does not require changes anytime the person holding that position are changed.

Tariff E.S. – Environmental Surcharge Tariff

Q: IS THE COMPANY PROPOSING TO CHANGE THE BASE AMOUNT OF ENVIRONMENTAL COSTS REFELECTED IN THE ENVIRONMENTAL SURCHARGE MONTHLY CALCULATIONS?

A: Yes. Company Witness Elliott will address changes regarding the Environmental Surcharge tariff in her testimony.

Tariff P.P.A – Purchase Power Adjustment

Q. IS THE COMPANY PROPOSING CHANGES TO TARIFF P.P.A.?

A. Yes. The Company is modifying the monthly rate formula. On Tariff Sheet No 35-1, under Rates, Subsection 2, the Company is adding a variable to the formula to read, "c .PE(m)= The cost of power purchased unrelated to forced generation or transmission outages that are calculated in accordance with the peaking unit equivalent methodology." The previous 2.c. is renumbered to be 2.d. The new formula will read, "Monthly P(m) = PPA(m) + RP(m)+PE(m) + CSIRP(m)." The new formula will allow the Company to recover the full cost of purchased power on a timely basis.

Tariff A.T.R. –Asset Transfer Rider

Q: IS THE COMPANY PROPOSING CHANGES TO THE A.T.R. TARIFF?

A: Yes. Because of the manner through which costs are recovered under Tariff A.T.R., the Company is modifying the Rate section on Tariff Sheet 36-1. The Company is eliminating the language, "and ending when the Commission sets new base rates for the Company that include Mitchell Units 1 and 2." And adding the language "Recovery under Tariff A.T.R. shall terminate on the effective date of new base rates for the Company that include Mitchell Units 1 and 2, except that the Company shall recover through the Residential Asset Transfer Adjustment and the All Other Classes Transfer Adjustment such amounts as required to ensure the Company recovers in the year new base rates for the Company are established that include Mitchell Units 1 and 2 a pro rata share (computed on a 365-day annual basis) of the $44 million annual revenue requirement under Tariff A.T.R..” The modification will allow a temporary extension of the Rider to allow the Company to recover the full amount of the authorized $44 million. Once the full amount has been recovered, the Rider will be withdrawn.

<u>Tariff D.S.M.C. – Demand-Side Management Adjustment Clause</u>

Q: IS THE COMPANY PROPOSING ANY CHANGES TO THE DSMC TARIFF?

A: No, not in this proceeding. The Company’s current demand-side management programs are the subject of a separate Commission proceeding, Case No. 2014-00271. Once the Commission has issued its final Order in that case, the Company will make any necessary amendments to the tariff pursuant to the Commission’s Order.

<u>Tariff E.D.R. – Economic Development Rider</u>

Q: IS THE COMPANY PROPOSING ANY CHANGES TO THE ECONOMIC DEVELOPMENT RIDER TARIFF?

A: No, not in this proceeding. The Economic Development Rider tariff is the subject of a separate Commission proceeding, Case No. 2014-00336. Once the

Commission has issued its final Order in that case, the Company will make any necessary amendments to the tariff pursuant to the Commission's Order.

Q: DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A: Yes.

Kentucky Power Company **Exhibit JAR-1**

Rockport Extension Proposed Revenue Allocation

Ln. No. (1)	Tariffs (2)	Proposed Billed Revenues (3)	Percent of Revenue (4)	Allocated $6.2 Million (5)	Proposed Billing Units kWh Sales (6)	kWh Rate All Other Customers (7)	kWh Rate IGS Customers (8)
1	Residential	$267,061,060	42.35%	$ 2,625,700	2,260,149,747		
2	SGS	$ 21,651,296	3.43%	$ 212,660	142,560,732		
3	MGS	$ 64,645,805	10.25%	$ 635,500	513,643,421		
4	LGS	$ 78,000,533	12.37%	$ 766,940	707,364,999		
5	OL	$ 8,191,296	1.30%	$ 80,600	37,640,598		
6	SL	$ 1,609,696	0.26%	$ 16,120	8,190,082		
7	MW	$ 395,083	0.06%	$ 3,720	3,864,039		
8	IGS	$ 189,000,671	29.97%	$ 1,858,140	2,818,677,591		
9	Total	$630,555,440	99.99%	$ 6,199,380	6,492,091,209		
10	New Rate					$0.001182	$0.000659

Exhibit JAR-2

Kentucky Power Company
Capacity Charge Tariff Revenues
October 1, 2013 to September 30, 2014

Ln No (1)	Month (2)	Year (3)	Total Ky Retail Billed & Accrued kWh (4)	Ky Retail CIP - TOD* Billed & Accrued kWh (5)	CIP - TOD Capacity Charge Rate Per kWh (6)	Ky Retail All Other Billed & Accrued kWh (7) = (4) - (5)	All Other Capacity Charge Rate Per kWh (8)	Total (9)
1	October	2013	497,904,629	179,117,536	$0.000667	318,787,093	$0.000970	$428,695
2	November	2013	570,541,462	188,257,047	$0.000667	382,284,415	$0.000970	$496,383
3	December	2013	601,269,198	178,635,737	$0.000667	422,633,461	$0.000970	$529,104
4	January	2014	727,096,121	187,522,268	$0.000667	539,573,853	$0.000970	$648,464
5	February	2014	590,212,723	161,235,143	$0.000667	428,977,580	$0.000970	$523,652
6	March	2014	626,175,478	173,811,498	$0.000667	452,363,980	$0.000970	$554,725
7	April	2014	440,658,617	173,969,661	$0.000667	266,688,956	$0.000970	$374,726
8	May	2014	524,708,651	193,559,040	$0.000667	331,149,611	$0.000970	$450,319
9	June	2014	513,007,262	178,848,316	$0.000667	334,158,946	$0.000970	$443,426
10	July	2014	507,524,113	162,904,164	$0.000667	344,619,949	$0.000970	$442,938
11	August	2014	521,897,278	181,426,199	$0.000667	340,471,079	$0.000970	$451,268
12	September	2014	432,907,942	144,068,608	$0.000667	288,839,334	$0.000970	$376,268
13	Total		6,553,903,474	2,103,355,217		4,450,548,257		$5,719,967

* Usage billed under Tariff RTP for customers who are usually on the CIP-TOD Tariff has been included in Column (5)

Kentucky Power Company
Analysis of
Over/(Under) Recovery of Fuel
Test Year Ended September 30, 2014

Ln No (1)	Month (2)	Year (3)	Generation Month KWH Sales (4)	Billed Olive Hill Vanceburg Sales (5)	Juris. KWH Sales (C4-C5) (6)	Total Company Fuel Cost (7)	Juris. Fuel Cost (C6*(C7/C4) (8)	Deferred Fuel (9)	Juris. Total Fuel Cost (C8+C9) (10)	Cents Per kWh (C7/C4) (11)	Billed and Accrued KWH (12)	Base Fuel (13)	FAC (C11-C13) (14)	Base Fuel Revenue (C12*C13) (15)	F.A.C. Revenue (C12*C14) (16)	Total Fuel Revenue (C15+C16) (17)	Over(Under) Recovery of Fuel (C17-C10) (18)
1	August	2013	542,214,000		542,214,000	$15,170,229	$15,170,229	$846,294	$16,016,523	0.02798	550,323,969	0.02840	(0.00042)				
2	September	2013	474,833,000		474,833,000	$12,129,595	$12,129,595	$1,401,633	$13,531,228	0.02554	453,917,512	0.02840	(0.00286)				
3	October	2013	486,952,000	6,679,100	480,272,900	$13,284,121	$13,101,914	($411,831)	$12,690,083	0.02728	497,904,629	0.02840	(0.00112)	$14,140,491	($209,120)	$13,931,371	$1,241,288
4	November	2013	579,155,000	7,869,700	571,285,300	$17,681,028	$17,440,774	($170,274)	$17,270,500	0.03053	570,541,462	0.02840	0.00213	$16,203,378	($1,631,749)	$14,571,629	($2,698,871)
5	December	2013	634,238,000	9,017,200	625,220,800	$16,892,829	$16,652,657	($2,400,476)	$14,252,181	0.02663	601,269,198	0.02840	(0.00177)	$17,076,045	($673,422)	$16,402,623	$2,150,442
6	January	2014	755,082,000	11,047,100	744,034,900	$19,958,870	$19,666,865	($2,444,502)	$17,222,363	0.02643	727,096,121	0.02840	(0.00197)	$20,649,530	$1,548,715	$22,198,245	$4,975,882
7	February	2014	626,869,000	9,156,500	617,712,500	$23,228,140	$22,888,853	($5,804,907)	$17,083,946	0.03705	590,212,723	0.02840	0.00865	$16,762,041	($1,044,677)	$15,717,364	($1,366,582)
8	March	2014	530,008,000	8,605,000	521,403,000	$18,353,423	$18,055,444	($4,933,030)	$13,122,414	0.03463	626,175,478	0.02840	0.00623	$17,783,384	($1,233,566)	$16,549,818	$3,427,404
9	April	2014	469,384,000	6,391,700	462,992,300	$17,722,956	$17,481,619	($592,942)	$16,888,677	0.03776	440,658,617	0.02840	0.00936	$12,514,705	$3,811,697	$16,326,402	($562,275)
10	May	2014	481,881,000	6,690,100	475,190,900	$17,055,704	$16,818,914	$1,073,615	$17,892,529	0.03539	524,708,651	0.02840	0.00699	$14,901,726	$3,268,935	$18,170,661	$278,132
11	June	2014	517,352,000	7,434,700	509,917,300	$17,994,542	$17,735,949	($61,597)	$17,674,352	0.03478	513,007,262	0.02840	0.00638	$14,569,406	$4,801,748	$19,371,154	$1,696,802
12	July	2014	533,564,000	7,733,400	525,830,600	$19,049,860	$18,773,754	($327,236)	$18,446,518	0.03570	507,524,113	0.02840	0.00730	$14,413,685	$3,547,594	$17,961,279	($485,239)
13	August	2014	531,708,000	7,894,600	523,813,400	$18,957,360	$18,675,888	($982,626)	$17,693,262	0.03565	521,897,278	0.02840	0.00725	$14,821,883	$3,329,705	$18,151,588	$458,326
14	September	2014	461,160,000	6,762,800	454,397,200	$17,026,696	$16,777,004	$2,494,343	$19,271,347	0.03692	432,907,942	0.02840	0.00852	$12,294,586	$3,160,228	$15,454,814	($3,816,533)
15	Oct-Sept Total		6,607,353,000	95,281,900	6,512,071,100	$217,205,528	$214,069,635	($14,561,463)	$199,508,172		6,553,903,474			$186,130,860	$18,676,088	$204,806,948	$5,298,776

Exhibit JAR-3

Kentucky Power Company
Analysis of Reconnect Charges

Line No.	Description	Reconnect Regular Hours - Day Shift (1)	Reconnect Into O. T. Hours - Day Shift (2)	Reconnect Call-Out Hours - Day Shift (3)	Reconnect Sunday/ Holidays - Day Shift (4)	Collection Trip Charge (5)	Bad Check Charge (6)	Meter Test Charge (7)	Meter Reading Check (8)	Total Additional Revenues (9)
1	Hours Worked	0.5	0.5	2.0	2.0	0.3	0.0	1.0	0.5	
2	Transportation Hours	0.5	1.0	1.0	1.0	0.5	0.0	0.5	0.5	
3	Hourly Labor Rate	25.48	25.48	25.48	25.48	25.48	0.00	32.87	25.48	
4	Overtime Adj.	0.00	12.74	12.74	25.48	0.00	0.00	0.00	0.00	
5	Hourly Labor Rate W/O.T. (Line 3 + Line 4)	25.48	38.22	38.22	50.96	25.48	0.00	32.87	25.48	
6	Labor Cost (Line 1 * Line 5)	12.74	19.11	76.44	101.92	6.37	3.12	32.87	12.74	
7	Transportation Hourly Rate	9.39	9.39	9.39	9.39	9.39	0.00	10.89	9.39	
8	Trans. Cost (Line 7 * Line 2)	4.70	9.39	9.39	9.39	4.70	0.00	5.45	4.70	
9	Fringe Benefits Rate	0.3020	0.1260	0.1260	0.1260	0.3020	0.3020	0.3020	0.3020	
10	Benefits Cost (Line 6 * Line 9)	3.85	2.41	9.63	12.84	1.92	0.94	9.93	3.85	
11	Bank Fees						14.65			
12	Total Cost (Line 6 + Line 8 + Line 10 + Line 11 = Line 12)	21.29	30.91	95.46	124.15	12.99	18.71	48.25	21.29	
13	Suggested Charge	21.00	30.00	95.00	124.00	13.00	18.00	48.00	21.00	
14	Current Charge	12.94	17.26	35.95	44.58	8.63	7.00	14.38	0.00	
15	Increase/(Decrease)	$8.06	$12.74	$59.05	$79.42	$4.37	$11.00	$33.62	$21.00	
16	12 Month 09/30/14 Actual No. of Trans.	6,134	427	368	27	31,077	2,736	55	257	
17	Total Additional Revenues	$49,440.04	$5,439.98	$21,730.40	$2,144.34	$135,806.49	$30,096.00	$1,849.10	$5,397.00	$251,903.35
18	Less:State Income Tax at 6.00%									$15,114
19	Less:Federal Tax At 35%									$82,876
20	Net Income Effect									$153,913
21	13 Month Average Equity as of September 30, 2014									$778,700,000
22	Effect on Return on Equity (Line 20 / Line 21)									0.02%

Exhibit JAR-4

Kentucky Power Company
Non-Recurring Charges at Proposed Rates
by Customer Class
Twelve Months Ending September 30, 2014

Ln No (1)	Description (2)	Reconnect $21.00 Charge (3)	Reconnect $30.00 Charge (4)	Reconnect $95.00 Charge (5)	Reconnect $124.00 Charge (6)	Collection Trip $13.00 Charge (7)	Bad Check $18.00 Charge (8)	Meter Test $48.00 Charge (9)	Meter Reading Check 21.00 Charge (10)	Class Revenue Increase (11)	Twelve Month September 30, 2014 Billed & Accrued Revenue (12)	Class Total Percent Change (13)
1	Residential	$46,393	$5,160	$20,845	$1,906	$122,749	$27,555	$1,513	$1,743	$227,864	$239,925,809	0.0950%
2	Commerical	$3,023	$280	$886	$238	$12,708	$2,530	$336	$1,260	$21,261	$104,680,619	0.0203%
3	Public Authority	$0	$0	$0	$0	$13	$11	$0	$315	$339	$19,745,753	0.0017%
4	School	$0	$0	$0	$0	$4	$0	$0	$0	$4	$19,042,856	0.0000%
5	Industrial	$16	$0	$0	$0	$170	$0	$0	$2,079	$2,266	$131,032,794	0.0017%
6	Mine Power	$8	$0	$0	$0	$162	$0	$0	$0	$170	$47,686,278	0.0004%
7	Public Street Lighting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,720,808	0.0000%
8	Total Incremental Increase	$49,440	$5,440	$21,730	$2,144	$135,806	$30,096	$1,849	$5,397	$251,903	$563,834,917	0.0447%
9	Total at Proposed Rates	$128,814	$12,810	$34,960	$3,348	$404,001	$49,248	$2,640	$5,397	$641,218		

Exhibit JAR-5

Kentucky Power Company
Twelve Months Ending September 30, 2014
Non-Recurring Charges
Monthly Break Down
Test Year Revenues

Ln No	Description	Oct 13	Nov 13	Dec 13	Jan 14	Feb 14	Mar 14	Apr 14	May 14	Jun 14	Jul 14	Aug 14	Sep 14	Total	Test Year Rate	Test Year Revenue Per Class
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	$12.94 Reconnect Charge															
1	Residential	998	384	201	98	134	286	620	659	510	615	690	561	5,756	$12.94	$74,482.64
2	Commerical	48	22	21	11	19	20	36	43	26	39	54	36	375	$12.94	$4,852.50
3	Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0	$12.94	$0.00
4	Mine Power	1	0	0	0	0	0	0	0	0	0	0	0	1	$12.94	$12.94
5	Industrial	0	0	0	1	0	0	1	0	0	0	0	0	2	$12.94	$25.88
6	Total	1047	406	222	110	153	306	657	702	536	654	744	597	6,134		$79,373.96
	$17.26 into Overtime															
7	Residential	66	20	12	9	8	27	48	51	29	35	56	44	405	17.26	$6,990.30
8	Commerical	4	0	5	0	0	1	3	1	4	1	0	3	22	17.26	$379.72
9	Total	70	20	17	9	8	28	51	52	33	36	56	47	427		$7,370.02
	$35.95 Call Out															
10	Residential	55	23	6	9	8	31	52	32	34	39	32	32	353	35.95	$12,690.35
11	Commerical	2	2	0	0	1	1	2	0	2	1	2	2	15	35.95	$539.25
12	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	35.95	$0.00
13	Total	57	25	6	9	9	32	54	32	36	40	34	34	368		$13,229.60
	$44.58 Sun. Holiday															
14	Residential	1	1	2	0	1	1	5	3	2	4	3	1	24	44.58	$1,069.92
15	Commerical	0	0	1	0	0	0	0	1	0	1	0	0	3	44.58	$133.74
16	Total	1	1	3	0	1	1	5	4	2	5	3	1	27		$1,203.66
	$8.63Collection Trip															
17	Residential	3007	2088	1630	2441	1495	2447	3023	2580	2293	2656	2345	2084	28,089	8.63	$242,408.07
18	Commerical	259	228	188	279	226	291	262	246	198	246	255	230	2,908	8.63	$25,096.04
19	Public Authority	0	0	0	0	0	0	1	1	0	1	0	0	3	8.63	$25.89
20	School	0	1	0	0	0	0	0	0	0	0	0	0	1	8.63	$8.63
21	Industrial	4	4	0	6	2	2	5	3	1	2	7	3	39	8.63	$336.57
22	Mine Power	2	4	5	1	3	5	4	2	2	3	3	3	37	8.63	$319.31
23	Public Street Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	8.63	$0.00
24	Total	3272	2325	1823	2727	1726	2745	3295	2832	2494	2908	2610	2320	31,077		$268,194.51
	$7.00 Bad Check Charge															
25	Residential	179	133	140	202	167	178	279	243	263	243	246	232	2,505	7.00	$17,535.00
26	Commerical	13	9	8	28	22	26	22	25	16	21	28	12	230	7.00	$1,610.00
27	Public Authority	0	0	0	0	0	0	0	1	0	0	0	0	1	7.00	$7.00
28	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	7.00	$0.00
29	Mine Power	0	0	0	0	0	0	0	0	0	0	0	0	0	7.00	$0.00
30	Total	192	142	148	230	189	204	301	269	279	264	274	244	2,736		$19,152.00
	$14.38 Meter Test															
31	Residential	1	0	1	9	15	8	0	2	2	3	3	1	45	14.38	$647.10
32	Commerical	1	1	0	3	1	1	0	3	0	0	0	0	10	14.38	$143.80
33	Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0	14.38	$0.00
34	Total	2	1	1	12	16	9	0	5	2	3	3	1	55		$790.90
	Meter Reading Check															
35	Residential	6	5	9	10	14	6	9	5	4	7	4	4	83		$0.00
36	Commerical	2	4	2	2	4	7	13	8	4	7	4	3	60		$0.00
36	Industrial	5	1	2	2	5	3	57	7	4	5	5	3	99		$0.00
37	Public Authority	2	1	1	2	1	1	3	1	3	0	0	0	15		$0.00
38	Total	15	11	14	16	24	17	82	21	15	19	13	10	257		$0.00
39	Total															$389,314.65

Exhibit JAR-6

Kentucky Power Company
Twelve Months Ending September 30, 2014
Non-Recurring Charges
Monthly Break Down
Monthly Break Down with Proposed Increase

Ln No	Description	Oct 13	Nov 13	Dec 13	Jan 14	Feb 14	Mar 14	Apr 14	May 14	Jun 14	Jul 14	Aug 14	Sep 14	Total	Proposed Increase	Proposed Increase Per Class
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	$12.94 Reconnect Charge															
1	Residential	998	384	201	98	134	286	620	659	510	615	690	561	5,756	$8.06	$46,393.36
2	Commerical	48	22	21	11	19	20	36	43	26	39	54	36	375	$8.06	$3,022.50
3	Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0	$8.06	$0.00
4	Mine Power	1	0	0	0	0	0	0	0	0	0	0	0	1	$8.06	$8.06
5	Industrial	0	0	0	1	0	0	1	0	0	0	0	0	2	$8.06	$16.12
6	Total	1047	406	222	110	153	306	657	702	536	654	744	597	6,134	$8.06	$49,440.04
	$17.26 into Overtime															
7	Residential	66	20	12	9	8	27	48	51	29	35	56	44	405	12.74	$5,159.70
8	Commerical	4	0	5	0	0	1	3	1	4	1	0	3	22	12.74	$280.28
9	Total	70	20	17	9	8	28	51	52	33	36	56	47	427	12.74	$5,439.98
	$35.95 Call Out															
10	Residential	55	23	6	9	8	31	52	32	34	39	32	32	353	59.05	$20,844.65
11	Commerical	2	2	0	0	1	1	2	0	2	1	2	2	15	59.05	$885.75
12	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	59.05	$0.00
13	Total	57	25	6	9	9	32	54	32	36	40	34	34	368	59.05	$21,730.40
	$44.58 Sun. Holiday															
14	Residential	1	1	2	0	1	1	5	3	2	4	3	1	24	79.42	$1,906.08
15	Commerical	0	0	1	0	0	0	0	1	0	1	0	0	3	79.42	$238.26
16	Total	1	1	3	0	1	1	5	4	2	5	3	1	27	79.42	$2,144.34
	$8.63Collection Trip															
17	Residential	3007	2088	1630	2441	1495	2447	3023	2580	2293	2656	2345	2084	28,089	4.37	$122,748.93
18	Commerical	259	228	188	279	226	291	262	246	198	246	255	230	2,908	4.37	$12,707.96
19	Public Authority	0	0	0	0	0	0	1	1	0	1	0	0	3	4.37	$13.11
20	School	0	1	0	0	0	0	0	0	0	0	0	0	1	4.37	$4.37
21	Industrial	4	4	0	6	2	2	5	3	1	2	7	3	39	4.37	$170.43
22	Mine Power	2	4	5	1	3	5	4	2	2	3	3	3	37	4.37	$161.69
23	Public Street Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	4.37	$0.00
24	Total	3272	2325	1823	2727	1726	2745	3295	2832	2494	2908	2610	2320	31,077	4.37	$135,806.49
	$7.00 Bad Check Charge															
25	Residential	179	133	140	202	167	178	279	243	263	243	246	232	2,505	11.00	$27,555.00
26	Commerical	13	9	8	28	22	26	22	25	16	21	28	12	230	11.00	$2,530.00
27	Public Authority	0	0	0	0	0	0	0	1	0	0	0	0	1	11.00	$11.00
28	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	11.00	$0.00
29	Mine Power	0	0	0	0	0	0	0	0	0	0	0	0	0	11.00	$0.00
30	Total	192	142	148	230	189	204	301	269	279	264	274	244	2,736	11.00	$30,096.00
	$14.38 Meter Test															
31	Residential	1	0	1	9	15	8	0	2	2	3	3	1	45	33.62	$1,512.90
32	Commerical	1	1	0	3	1	1	0	3	0	0	0	0	10	33.62	$336.20
33	Public Authority	0	0	0	0	0	0	0	0	0	0	0	0	0	33.62	$0.00
34	Total	2	1	1	12	16	9	0	5	2	3	3	1	55	33.62	$1,849.10
	Meter Reading Check															
35	Residential	6	5	9	10	14	6	9	5	4	7	4	4	83	21.00	$1,743.00
36	Commerical	2	4	2	2	4	7	13	8	4	7	4	3	60	21.00	$1,260.00
36	Industrial	5	1	2	2	5	3	57	7	4	5	5	3	99	21.00	$2,079.00
37	Public Authority	2	1	1	2	1	1	3	1	3	0	0	0	15	21.00	$315.00
38	Total	15	11	14	16	24	17	82	21	15	19	13	10	257	21.00	$5,397.00
39	Total															$251,903.35

Exhibit JAR-7

P.S.C KY. NO. 10

N

KENTUCKY POWER COMPANY
101A ENTERPRISE DRIVE
P.O. BOX 5190
FRANKFORT, KY 40602

RATES-CHARGES-RULES-REGULATIONS
FOR FURNISHING

ELECTRIC SERVICE

IN THE KENTUCKY TERRITORY SERVED
BY KENTUCKY POWER COMPANY
AS STATED ON SHEET NO. 1

FILED WITH THE PUBLIC SERVICE COMMISSION
OF
KENTUCKY

DATE OF ISSUE: December 23, 2014
DATE EFFECTIVE: January 23, 2015
ISSUED BY: John A. Rogness III
TITLE: Director Regulatory Services

N

INDEX

(Cont'd on Sheet No. 1-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 1-2
CANCELLING P.S.C. KY. NO. 10 __________ SHEET NO. 1-2

INDEX (Cont'd)

(Cont'd on Sheet No. 1-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-Xxxx Dated Xxxxxxxx

INDEX (Cont'd)

THE ABOVE TARIFFS ARE APPLICABLE TO THE ENTIRE TERRITORY SERVED BY KENTUCKY POWER COMPANY IN BOYD, BREATHITT, CARTER, CLAY, ELLIOTT, FLOYD, GREENUP, JOHNSON, KNOTT, LAWRENCE, LESLIE, LETCHER, LEWIS, MAGOFFIN, MARTIN, MORGAN, OWSLEY, PERRY, PIKE AND ROWAN COUNTIES.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-Xxxx Dated Xxxxxxxx

TERMS AND CONDITIONS OF SERVICE

1. APPLICATION.

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request and the Customer shall elect upon which tariff applicable to his service his application shall be based. A copy of the tariff is also available on-line at www.kentuckypower.com. T

If the Company requires a written agreement from a Customer before service will be commenced, a copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. INSPECTION.

The Customer is responsible for the proper installation and maintenance of the customer's wiring and electrical equipment and the customer shall at all times be responsible for the character and condition thereof. The Company has no obligation to undertake inspection thereof and in no event shall be responsible therefore. However, the Company may refuse to connect to the customer's system if such connection is deemed unsafe by the Company.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until the Company has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and/or tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefore. No responsibility shall attach to the Company because of any waiver of this requirement.

3. SERVICE CONNECTIONS.

Service connections will be provided in accordance with 807 KAR 5:041, Section 10.

The Customer should in all cases consult the Company before the Customer's premises are wired to determine the location of Company's point of service connection.

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain equipment specified by the Company, the Company may supply or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building.

All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

(Cont'd on Sheet No. 2-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

4. DEPOSITS.

Prior to providing service or at any time thereafter, the Company may require a cash deposit or other guaranty acceptable to the Company to secure payment of bills except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained by the Company during the entire time that the account remains active. T T

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied by the Company as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention of any deposit or guaranty by the Company prior to final settlement is not a payment or partial payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria, which may be considered by the Company cumulatively. T

1. Satisfactory payment criteria, which may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments and having no meter diversion or theft of service. T T
2. Meeting satisfactory credit criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources as well as historic and ongoing payment and credit history with Company. T
3. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit.
4. Providing evidence of other collateral acceptable to Company. T
5. Checkless Payment Plan (CPP) T

C. Method of Determination

1. Calculated Deposits

   a. Deposit amounts paid by residential customers shall not exceed a calculated amount based upon actual usage data of the Customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the Customer's actual or estimated annual bill.

   b. Deposit amounts paid by commercial and industrial customers shall not exceed a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill.

(Cont'd on Sheet No. 2-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

4. DEPOSITS, (Cont'd.)

D. Additional or Supplemental Deposit Requirement

An additional or supplemental deposit may be required if the Customer does not maintain a satisfactory credit criteria or payment history. If a change in usage or classification of service has occurred, the customer may be required to pay an additional deposit up to 2/12 of the annual usage. The Customer will receive a message on the bill informing the Customer that if the account is not current by the specified date listed an additional or supplement deposit will be charged to the account the next time the account is billed. T T

1. Satisfactory payment criteria is defined as paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments and having no meter diversion or theft of service. N

2. A nonresidential customer does not maintain satisfactory credit criteria when its credit score at any national independent credit rating service falls to a level that is deemed to be vulnerable to nonpayment, including but not limited to: "C" level at Valueline, a "BB+" level at Standard and Poor's or Fitch, "Ba3" at Moody's. If a nonresidential customer is not rated by a national independent credit rating service, its credit may be evaluated by using credit scoring services, public record financial information, or financial scoring and modeling services, and if it is deemed that the customer is vulnerable to nonpayment, a deposit may be required. N

E. Recalculation of Customers Deposit

When a deposit is held longer than 18 months, the Customer may request that the deposit be recalculated based on the Customer's actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential Customer or 10 percent for a non-residential Customer, the Company may collect any underpayment and shall refund any overpayment by check or credit to the Customer's bill. No refund will be made if the Customer's bill is delinquent at the time of the recalculation.

5. PAYMENTS,

Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer's service.

A. Equal Payment Plan

Residential Customers have the option of paying a fixed amount each month under the Company's Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customers' estimated annual usage. The payment amount is subject to periodic review and adjustment during the budget year to more accurately reflect actual usage. The normal plan period is 12 months, which may commence in any month.

In the last month of the plan, if the actual usage during the plan period exceeds the amount billed, the Customer will be billed for the balance due. If an overpayment exists, the amount of overpayment will either be refunded to the Customer or credited to the last bill of the period. If a Customer discontinues service with the Company under the Equal Payment Plan, any amounts not yet paid shall become payable immediately.

If a Customer fails to pay bills as rendered under the Equal Payment Plan, the Company reserves the right to revoke the plan, restore the Customer to regular billing, require immediate payment of any deficiency, and require a cash deposit or other guaranty to secure payment of bills.

(Cont'd on Sheet No. 2-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-4
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-4

TERMS AND CONDITIONS OF SERVICE (Cont'd)

B. Average Monthly Payment Plan (Amp)

The Average Monthly Payment Plan (AMP Plan) is available to the following applicable tariffs; R.S.; R.S.-L.M-T.O.D.; R.S.-T.O.D 2.; S.G.S., and S.G.S.-T.O.D. When mutually agreeable the AMP Plan may be offered by the Company to Customers serviced under other tariffs. T

The AMP Plan is designed to allow the Customer to pay an average amount each month based upon the actual billed amounts during the past twelve (12) months. The average payment amount is based upon the current month's total bill plus the eleven (11) preceding months. That result is divided by the total billing days associated with the billings to determine a per day average. The daily average amount is multiplied by thirty (30) to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average. Again the daily average amount is multiplied by thirty (30) to find the new average payment amount. The average monthly payment amount is calculated each and every month in this manner.

The difference between the actual billings and the AMP Plan billings will be carried in a deferred balance. Both the debit and credit differences will accumulate in the deferred balance for the duration of the AMP Plan year, which is twelve consecutive billings months. At the end of the AMP Plan year (anniversary month), the current month's billing plus the eleven (11) preceding month's billing is summed and divided by the total billing days associated with the billings to determine a per day average. That result is multiplied by thirty (30) to calculate the AMP Plan's monthly payment amount. In addition, the net accumulated deferred balance is divided by 12. This result is added or subtracted to the calculated average payment amount starting with the next billing of the new AMP plan year and will be used in the average payment amount calculation for the remaining AMP plan year. Settlement occurs only when participation in the AMP Plan is terminated. This happens if any account is final billed, if the customer requests termination, or at the Company's discretion when the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the billing now due.

In such instances where sufficient billing history is not available, an AMP Plan may be established by using the actual billing history available throughout the first AMP Plan year.

C. All Payments.

All bills are payable at the business offices or authorized collection agencies of the Company within the time limits specified in the tariff. Failure to receive a bill will not entitle a Customer to any discount or to the remission of any charges for non-payment within the time specified. The word "month" as used herein and in the tariffs is hereby defined to be the elapsed time between 2 successive meter readings approximately 30 days apart.

In the event of the stoppage of or the failure of any meter to register the full amount of energy consumed, the Customer will be billed for the period based on an estimated consumption of energy in a similar period of like use.

The tariffs of the Company are met if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. To discourage delinquency and encourage prompt payment within the specified time limit, certain tariffs contain a delayed payment charge, which may be added in accordance with the tariff under which service is provided. Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding 6 months.

6. **UNDERGROUND SERVICE.**

When a real estate developer desires an underground distribution system within the property which he is developing or when a Customer desires an underground service, the real estate developer or the Customer, as the case may be, shall pay the Company the difference between the anticipated cost of the underground facilities so requested and the cost of the overhead facilities which would ordinarily be installed in accordance with 807 KAR 5:041, Section 21, and the Company's underground service plan as filed with the Public Service Commission. Upon receipt of payment, the Company will install the underground facilities and will own, operate and maintain the same.

(Cont'd on Sheet No. 2-5)

DATE OF ISSUE: December 23, 2014
DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III
TITLE: Director Regulatory Services
By Authority Of Order By The Public Service Commission
In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-5
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-5

TERMS AND CONDITIONS OF SERVICE (Cont'd)

7. **COMPANY'S LIABILITY**

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an event of Force Majeure. Force Majeure consists of an event or circumstance which prevents Company from providing service, which event or circumstance was not anticipated, which is not in the reasonable control of, or the result of negligence of, the Company, and which, by the exercise of due diligence, Company is unable to overcome or avoid or causes to be avoided. Force Majeure events includes act of God, the public enemy, accidents, labor disputes, orders or acts of civil or military authority, breakdowns or injury to the machinery, transmission lines, distribution lines or other facilities of the Company, or extraordinary repairs.

Unless otherwise provided in a contract between the Company and Customer, the point at which service is delivered by Company to Customer, to be known as "delivery point," shall be the point at which the Customer's facilities are connected to the Company's facilities. The metering device is the property of the Company. The meter base, connection, grounds and all associated internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the Customer's use of their equipment or occasioned by the energy furnished by the Company beyond the delivery point.

Beginning September 1, 2014 and thereafter, any new installation, upgrade or other modification of an existing meter installation shall be made using only Company supplied or approved meter bases. A list of Company-approved meter bases and specifications can be found on the Company's website at: www.kentuckypower.com.

The Customer shall provide and maintain suitable protective devices on their equipment to prevent any loss, injury or damage that might result from single phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury or damage resulting from a single phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices. The Company shall not be liable for any damages, whether direct, incidental or consequential, including, without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations, or irregularity in the supply of energy.

The Company is not responsible for loss or damage caused by the disconnection or reconnection of its facilities. The Company is not responsible for loss or damages caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus, which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

8. **CUSTOMER'S LIABILITY.**

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the Customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the Customer.

Customers will be responsible for tampering with, interfering with, or breaking of seals of meters, or other equipment of the Company installed on the Customer's premises. The Customer hereby agrees that no one except the employees of the Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus, which shall be the property of the Company.

(Cont'd on Sheet 2-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

8. **CUSTOMER'S LIABILITY (Cont'd)**

The Company shall have the right at all reasonable hours to enter the premises of the Customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause.

9. **EXTENSION OF SERVICE.**

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customers other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

For service to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide such new facilities at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to serve the load and the estimated revenue for one year; (c) if the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed.

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer's requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to serve shall be the sum of the following components:

1. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer's requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.

2. The annual energy costs based on the latest available production costs related to the Customer's estimated annual energy use requirements.

3. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

(Cont'd on Sheet No. 2-7)

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-7
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-7

TERMS AND CONDITIONS OF SERVICE (Cont'd)

9. **EXTENSION OF SERVICE (Cont'd)**

If the estimated revenue for one year is greater than the cost to serve as described herein, the Company may provide any new local facilities required at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in revenue.

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the company may require the Customer to execute an Advance and Refund Agreement where the Company reasonably questions the longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customers shall pay the company the estimated total installed cost of the required new facilities which advance could be refunded over a five year period under certain circumstances. Over the five year period the Customer' electric bill would be credited each month up to the amount of 1/60th of the total amount advanced.

10. **EXTENSION OF SERVICE TO MOBILE HOME.**

The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

11. **LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT.**

The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

12. **BILLING FORM.**

Pursuant to 807 KAR 5:006, Section 7 (3) copies of the billing forms used by the Company are shown on Sheet Nos. 2-12 thru 2-17. T

13. **RATE SCHEDULE SELECTION.**

The Company will explain to the Customer, at the beginning of service or upon request the Company's rates available to the Customer. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change their initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedule.

(Cont'd on Sheet No. 2-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-8
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-8

TERMS AND CONDITIONS OF SERVICE (Cont'd)

14. **MONITORING USAGE.**

At least once quarterly the Company will monitor the usage of each customer according to the following procedure: T

1. The Customer's monthly usage will be compared with the usage of the corresponding period of the previous year.
2. If the monthly usage for the two periods is substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.
3. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the Customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.
4. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, the Company will contact the Customer to determine whether there have been changes that explain the increased or decreased usage.
5. Where the deviation is not otherwise explained, the Company will test the Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.
6. The Company will notify the customers of the investigation, its findings, and any refunds or back billing in accordance with 807 KAR 5:006, Section 11(4) and (5). T

In addition to the quarterly monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading, billing processes, or customer inquiry. T

15. **USE OF ENERGY BY CUSTOMER.**

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

Upon the expiration of an electric service contract, if required by the terms of the tariff, the Customer may elect to renew the contract upon the same or another tariff published by the Company available to the Customer and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer.

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric energy must not be used in such a manner as to cause unprovided for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

(Cont'd on Sheet No. 2-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

15. **USE OF ENERGY BY CUSTOMER. (Cont'd)**

No attachment of any kind whatsoever may be made to the Company's lines, poles, cross arms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devices, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load.

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs, which specifically provide for same.

The Customer shall not be permitted to operate generating equipment in parallel with the Company's service except with express written consent of the Company.

Resale of energy will be permitted only with express written consent by the Company.

16. **RESIDENTIAL SERVICE.**

Except as otherwise provided in these tariffs, individual residences shall be served individually with single-phase service T
under the applicable residential service tariff. Customer may not take service for 2 or more separate residences through a single point of delivery under any tariff. Exclusions may be allowed pursuant to 807 KAR 5:046 (Prohibition of master metering).

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional or gainful purposes, which requires three phase service or which requires service to motors in excess of 10 HP each. Under these circumstances, Customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential service tariff and the other uses as enumerated above are served through a separate meter or meters under the applicable general service tariff; or (2) taking the entire service under the applicable general service tariff.

Detached building or buildings, actually appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the Customer's residence wiring through the residence meter and under the applicable residential service tariff.

17. **DENIAL OR DISCONTINUANCE OF SERVICE.**

The Company reserves the right to refuse or discontinue service to any customer if the customer is indebted to the Company T
for any service theretofore rendered at any location; provided however, the customer shall be notified in writing in T
accordance with 807 KAR 5:006, Section *15*, before disconnection of service. T

Any discontinuance of service shall not terminate the contract for electric service between the Company and the applicant or customer nor shall it abrogate any minimum charge, which may be effective.

(Cont'd on Sheet No. 2-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-10
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-10

TERMS AND CONDITIONS OF SERVICE (Cont'd)

18. **EMPLOYEE'S DISCOUNT.**

Regular employees who have been in the Company's employ for 6 months or more may, at the discretion of the Company, receive a reduction in their residence electric bills for the premises occupied by the employee.

19. **SPECIAL CHARGES.**

A. Reconnection and Disconnect Charges

In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 9 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 16 shall be exempt from the reconnect charges.

1. Reconnect for nonpayment during regular hours..........................$ 21.00 I
2 Reconnect at the end of the day (No "Call Out" required)............ $ 30.00 I
3. Reconnect for nonpayment when a "Call Out" is required prior to 10:00 PM N
(A "Call Out" is when an employee must be called in to work on an overtime basis to make the reconnect trip. Reconnection for nonpayment will not be made N
when a "Call Out" after 10:00 p.m. is required).......................... $ 95.00 I
4. Reconnect for nonpayment when double time is required
(Sunday and Holiday)... $ 124.00 I
5. Termination or field trip... $ 13.00 I

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

B. Meter Reading Check N

Pursuant to 807 KAR 5:006, Section 9 (3) (d) in cases where a customer requests a meter be reread, and the second reading shows the original reading was correct, the Customer will be charged a fee of $21.00 to cover the handling cost. N

C. Returned Check Charge

In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of $18.00 to cover the handling costs. I

D. Meter Test Charge

Where test of a meter is made upon written request of the Customer pursuant to 807 KAR 5:006, Section 19, the Customer will be charged $48.00 if such test shows that the meter was not more than two percent (2%) fast. I

(Cont'd on Sheet No. 2-11)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

19. **SPECIAL CHARGES. CONT'D**

E. Work performed on Company's Facilities at Customer's Requests

Whenever, at the request and for the benefit of the Customer, work is performed on the Company's facilities, including the relocation, or replacement of the Company's facilities, the Customer shall pay to the Company in advance of the Company undertaking the work the estimated total cost of such work. This cost shall be itemized by major categories and shall include the Company's overheads and shall be credited with the net value of any salvageable material. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the Customer.

Reasonable notice of not less than three working days shall be given to the Company for all requested work except for the covering of the Company's lines. Notice of any request for the Company to cover its lines shall be given at least two days in advance. The Company will endeavor to comply with all timely requests, but work may be delayed because of demands on the Company's personnel and equipment.

If the cost, as calculated above, is $500 or less for covering the Company's distribution facilities no charge will be imposed. All costs in excess of $500 for covering the Company's distribution facilities, shall be paid by the Customer, in advance of the Company undertaking the work. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer.

(Cont'd on Sheet No. 2-12)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)
Residential Bill Form Page 1

KENTUCKY POWER
A unit of American Electric Power

Account Number
030-999-999-9-9
CY XX
XXXXXXX

$XXX.XX	$__________
Total Amount Due	Amount Enclosed
Due MM/DD, Add $XX.XX After This Date	

Send Inquires To:
PO BOX 24401
CANTON, OH 44701-4401
R-00-999999999

KPCo RESIDENTIAL CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Make Check Payable and Send To:
KENTUCKY POWER COMPANY
PO BOX 24410
CANTON OH 44701-4410

999999999000000000000000009999999999999999999000009999999999999999999999999999999999900000000000

Please tear on dotted line

Return top portion with your payment

Service Address:
KPCo RESIDENTIAL CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Rate Tariff: Residential Service -015

Account Number	Total Amount Due	Due Date
030-999-999-9-9	$XXX.XX	MM/DD/YY
Meter Number	**Cycle-Route**	**Bill Date**
999999999	XX-XX	MM/DD/YY

Questions about Bill or Service, Call:
Call: 1-800-572-1113
Pay By Phone: 1-800-611-0964

KPCo Messages

Got a new dog in your yard? Let us know about it. Call the number on your bill so we can note it on your account.

You can now reach our customer service representatives 24 hours a day, 7 days a week. Please help us by having your account number when you call.

Flip the Switch and turn off your paper bill! You will gain the benefit of receiving an email when your bill is ready to be viewed and the security of viewing it safely anytime, anywhere.

Stealing copper is illegal and can have deadly consequences. Reporting copper theft could save a life. If you have any information, please call 1-866-747-5845.

Having a phone number for this address can help us serve you better, especially when storms cause service interruptions.

Previous Charges:			
Total Amount Due At Last Billing	$	XXX.XX	
Payment MM/DD/YY - Thank You		XXX.XX	
Previous Balance Due	$	XXX.XX	
Current KPCo Charges:			
Tariff 015 - Residential Service MM/DD/YY			
Rate Billing	$	XXX.XX	
Fuel Adj @ 0.XXXXXXX Per KWH		XX.XX	
DSM Adj @0.XXXXXX Per KWH		X.XX	
Residential HEAP @ $0.15		0.15	
Kentucky Economic Development Surcharge @ $0.15		0.15	N
Capacity Charge @ 0.XXXXXX Per KWH		X.XX	
Big Sandy 1 Operations Rider @ 0.XXXXX Per KWH		XX.XX	N
Asset Transfer Rider @ X.XXXXXX%		XX.XX	
PJM Rider @ 0.XXXX Per KWH		XX.XX	N
NERC Cybersecurity Rider @ 0.XXXX Per KWH		XX.XX	N
Environmental Adj X.XXXXXX%		XX.XX	
Big Sandy Retirement Rider @ X.XXXXXX%		XX.XX	N
Purchased Power Adjustment @ 0.XXXXXX Per KWH		XX.XX	
Green Pricing XXX Blocks		XX.XX	
School Tax		XX.XX	
Franchise Tax		XX.XX	
State Sales Tax		XX.XX	
Current Electric Charges Due	$	XXX.XX	
Homeserve Warranty Service (855-769-6267)	$	XX.XX	
Total Amount Due	$	**XXX.XX**	
Due MM/DD, Add $XX.XX After This Date			

(Cont'd on Sheet No. 2-13)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-13
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-13

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Residential Bill Form _ Page 2

Homeserve USA is optional. Homeserve USA is not the sames as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated service from KPCO.

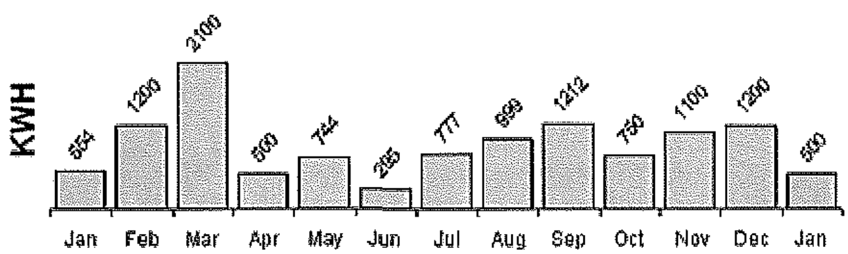
www.kyelectricalprotectionplan.com

Visit us at www.KentuckyPower.com
Rates available on request
See other side for Important Information

AEP KENTUCKY POWER®
A unit of American Electric Power

Meter	Service Period		Meter Reading Detail			
Number	From	To	Previous	Code	Current	Code
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier X.XXXX			Metered Usage X,XXX KWH			
Next scheduled read date should be between MM/DD and MM/DD						

13 Month Usage History **Total KWH for Past 12 Months is XX,XXX**



Month	Total KWH	Days	KWH Per Day	Cost Per Day	Average Temperature
Current	XXX	XX	X,XXX	$XXX.XX	66° F
Previous	XXX	XX	X,XXX	$XXX.XX	66° F
One Year Ago	XXX	XX	X,XXX	$XXX.XX	48° F
Your Average Monthly Usage: X,XXX KWH					

(Cont'd on Sheet No. 2-14)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-14
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-14

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Small Commercial Bill Form Page 1

AEP KENTUCKY POWER
A unit of American Electric Power

Send Inquires To:
PO BOX 24401
CANTON, OH 44701-4401
R-00-999999999

Account Number
030-999-999-9-9
CY XX
XXXXXXX

$XXX.XX	$________
Total Amount Due	Amount Enclosed
Due MM/DD, Add $XX.XX After This Date	

KPCo SMALL GEN SERV CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Make Check Payable and Send To:
KENTUCKY POWER COMPANY
PO BOX 24410
CANTON OH 44701-4410

999999999000000000000000000999999999999999999900000999999999999999999999999999999999900000000000000

Please tear on dotted line — Return top portion with your payment

Service Address:
KPCo SMALL GEN SERV CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Rate Tariff:Small General Service - 211

Account Number	Total Amount Due	Due Date
030-999-999-9-9	$XXX.XX	MM/DD/YY
Meter Number	Cycle-Route	Bill Date
999999999	XX-XX	MM/DD/YY

Questions about Bill or Service, Call:
Call: 1-800-572-1113
Pay By Phone: 1-800-611-0964

KPCo Messages
Got a new dog in your yard? Let us know about it. Call the number on your bill so we can note it on your account.

You can now reach our customer service representatives 24 hours a day, 7 days a week. Please help us by having your account number when you call.

Flip the Switch and turn off your paper bill! You will gain the benefit of receiving an email when your bill is ready to be viewed and the security of viewing it safely anytime, anywhere.

Stealing copper is illegal and can have deadly consequences. Reporting copper theft could save a life. If you have any information, please call 1-866-747-5845.

Previous Charges:			
Total Amount Due At Last Billing	$	XXX.XX	
Payment MM/DD/YY - Thank You		XXX.XX	
Previous Balance Due	$	XXX.XX	
Current KPCo Charges:			
Tariff 211 - Small General Service MM/DD/YY			
Rate Billing	$	XXX.XX	
Fuel Adj @ 0.XXXXXXX Per KWH		XX.XX	
DSM Adj @0.XXXXXX Per KWH		X.XX	
Capacity Charge @ 0.XXXXXX Per KWH		X.XX	
Kentucky Economic Development Surcharge @ $0.15		0.15	N
Big Sandy 1 Operations Rider @ 0.XXXXX Per KWH		XX.XX	N
Asset Transfer Rider @ X.XXXXXX%		XX.XX	
PJM Rider @ 0.XXXX Per KWH		XX.XX	N
NERC Cybersecurity Rider @ 0.XXXX Per KWH		XX.XX	N
Environmental Adj X.XXXXXX%		XX.XX	
Big Sandy Retirement Rider @ X.XXXXXX%		XX.XX	N
Purchased Power Adjustment @ 0.XXXXXX Per KWH		XX.XX	
Green Pricing XXX Blocks		XX.XX	
School Tax		XX.XX	
Franchise Tax		XX.XX	
State Sales Tax		XX.XX	
Current Electric Charges Due	$	XXX.XX	
Total Amount Due	$	**XXX.XX**	
Due MM/DD, Add $XX.XX After This Date			

(Cont'd on Sheet No. 2-15)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Small Commercial Bill Form – Page 2

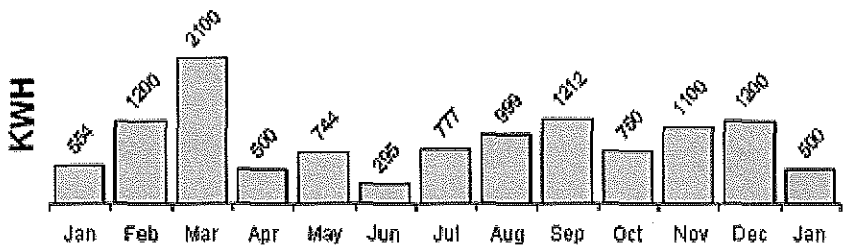
Having a phone number for this address can help us serve you better, especially when storms cause service interruptions.

Visit us at www.KentuckyPower.com
Rates available on request
See other side for Important Information

AEP KENTUCKY POWER
A unit of American Electric Power

Meter	Service Period		Meter Reading Detail			
Number	From	To	Previous	Code	Current	Code
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier X.XXXX			Metered Usage X,XXX KWH			
Next scheduled read date should be between MM/DD and MM/DD						

13 Month Usage History **Total KWH for Past 12 Months is XX,XXX**



Month	Total KWH	Days	KWH Per Day	Cost Per Day	Average Temperature
Current	XXX	XX	X,XXX	$XXX.XX	66° F
Previous	XXX	XX	X,XXX	$XXX.XX	66° F
One Year Ago	XXX	XX	X,XXX	$XXX.XX	48° F
Your Average Monthly Usage: X,XXX KWH					

(Cont'd on Sheet No. 2-16)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Large Commercial and Industrial Bill Form – Page 1

AEP KENTUCKY POWER
A unit of American Electric Power

Send Inquires To:
PO BOX 24401
CANTON, OH 44701-4401
R-00-999999999

Account Number
030-999-999-9-9
CY XX
XXXXXXX

$X,XXX.XX	$_______
Total Amount Due	Amount Enclosed
Due MM/DD, Add $XX.XX After This Date	

KPCo LARGE POWER CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Make Check Payable and Send To:
KENTUCKY POWER COMPANY
PO BOX 24410
CANTON OH 44701-4410

9999999990000000000000000009999999999999999999000009999999999999999999999999999999999000000000000000

Please tear on dotted line Return top portion with your payment

Service Address:
KPCo LARGE POWER CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Rate Tariff: Large General Service -244 Page 1 of 2

Account Number	Total Amount Due	Due Date
030-999-999-9-9	$X,XXX.XX	MM/DD/YY
Meter Number	**Cycle-Route**	**Bill Date**
999999999	XX-XX	MM/DD/YY

Questions about Bill or Service, Call:
Call: 1-800-572-1113
Pay By Phone: 1-800-611-0964

KPCo Messages
Got a new dog in your yard? Let us know about it. Call the number on your bill so we can note it on your account.

You can now reach our customer service representatives 24 hours a day, 7 days a week. Please help us by having your account number when you call.

Flip the Switch and turn off your paper bill! You will gain the benefit of receiving an email when your bill is ready to be viewed and the security of viewing it safely anytime, anywhere.

Stealing copper is illegal and can have deadly consequences. Reporting copper theft could save a life. If you have any information, please call 1-866-747-5845.

Previous Charges:			
Total Amount Due At Last Billing	$	X,XXX.XX	
Payment MM/DD/YY - Thank You		X,XXX.XX	
Previous Balance Due	$	X,XXX.XX	
Current KPCo Charges:			
Tariff 244 - Large General Service MM/DD/YY			
Rate Billing	$	X,XXX.XX	
Fuel Adj @ 0.XXXXXXX Per KWH		XXX.XX	
DSM Adj @0.XXXXXX Per KWH		XXX.XX	
Capacity Charge @ 0.XXXXXX Per KWH		XX.XX	
Kentucky Economic Development Surcharge @ $0.15		0.15	N
Big Sandy 1 Operations Rider @ 0.XXXXX Per KWH		XX.XX	N
Asset Transfer Rider @ X.XXXXXX%		XX.XX	
PJM Rider @ 0.XXXX Per KWH		XX.XX	N
NERC Cybersecurity Rider @ 0.XXXX Per KWH		XX.XX	N
Environmental Adj X.XXXXXX%		XX.XX	
Big Sandy Retirement Rider @ X.XXXXXX%		XX.XX	N
Purchased Power Adjustment @ 0.XXXXXX Per KWH		XX.XX	
Green Pricing XXX Blocks		XX.XX	
School Tax		XX.XX	
Franchise Tax		XX.XX	
State Sales Tax		XX.XX	
Current Electric Charges Due	$	X,XXX.XX	
Total Amount Due	$	**X,XXX.XX**	
Due MM/DD, Add $XX.XX After This Date			

(Cont'd on Sheet No. 2-17)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

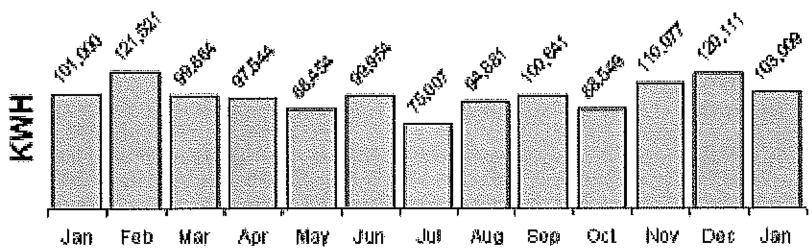
Large Commercial and Industrial Bill Form – Page 2

Send Inquiries To
PO BOX 24401
CANTON, OH 44701-4401
R-00-999999999

Service Address
KPCo LARGE POWER CUSTOMER
123 ANY STREET
ANY CITY, KY 99999-9999

Meter	Service Period		Meter Reading Detail			
Number	From	To	Previous	Code	Current	Code
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier XXX.XXXX			Metered Usage XXX,XXX KWH			
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier XXX.XXXX			Metered Usage XXX.XXX KW			
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier XXX.XXXX			Metered Usage XXX,XXX KVARH			
Next Scheduled read date should be between MM/DD and MM/DD						

13 Month Usage History Total KWH for Past 12 Months is X,XXX,XXX



Meter Number	Cycle-Route	Bill Date
999999999	99-99	MM/DD/YY

Month	Total KWH	Days	KWH Per Day	Cost Per Day	Average Temperature
Current	XXX,XXX	XX	X,XXX	$XXX.XX	68° F
Previous	XXX,XXX	XX	X,XXX	$XXX.XX	68° F
One Year Ago	XXX,XXX	XX	X,XXX	$XXX.XX	49° F
Your Average Monthly Usage: XXX,XXX KWH					

Stealing copper is illegal and can have deadly consequences. Reporting copper theft could save a life. If you have any information, please call 1-866-747-5845.

Having a phone number for this address can help us serve you better, especially when storms cause service interruptions.

Adjusted Usage MM/YY				
	Power	Power Factor	Comp. Meter	
	Factor	Constant	Multiplier	
Metered Usage	(XX.X)	(XXX.XXXX)		Billing Usage
XXX,XXX				XXX,XXX KWH
XXX.XXX				XXX.XXX KW
XXX,XXX				XXX,XXX KVARH
Contract Capacity = X,XXXX.X		High Prev Demand = X,XXX.X On-Pk		
		High Prev Demand = X,XXX.X Off-Pk		

Visit us at www.KentuckyPower.com
Rates available on request
See other side for important information

AEP KENTUCKY POWER
A unit of American Electric Power

Additional Messages

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM

The Company's Capacity and Energy Control Program consists of:

I. Procedures During Abnormal System Frequency

II. Capacity Deficiency Program

III. Energy Emergency Control Program

A copy of the Company's Emergency Operating Plan was filed with the Kentucky Public Service Commission on May 1, 2014 in Administrative Case No. 345 in compliance with the Commission's Order dated May 18, 1993. T

I. PROCEDURES DURING ABNORMAL SYSTEM FREQUENCY

A. INTRODUCTION

Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP program, which is in accordance with ECAR Document 3, is noted below.

B. PROCEDURES AEP/PJM

1. From 59.8 – 60.2 Hz to the extent practicable utilize all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the System during the emergency. For rapid frequency decline, only that capacity on-line and automatically responsive to frequency (spinning reserve), and such items as interconnection assistance and load reductions by automatic means are of assistance in arresting the decline in frequency.

   If the frequency decline is gradual, the Generation/Production Optimization Group, particularly in the deficient area, should invoke non-automatic procedures involving operating and emergency reserves. These efforts should continue until the frequency decline is arrested or until automatic load-shedding devices operate at subnormal frequencies.

2. At 59.75 Hz
   a. Suspend Automatic Generation Control (AGC)
   b. Notify Interruptible Customers to drop load

3. At 59.5 Hz automatically shed 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

4. At 59.4 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

5. At 59.3 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

6. At 59.1 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

7. At 59.0 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

8. At 58.9 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

(Cont'd on Sheet 3-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

PROCEDURES DURING ABNORMAL SYSTEM FREQUENCY (cont'd)

9. At 58.2 Hz automatically trip the D.C. Cook Nuclear Units 1 and 2.

10. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

If at any time in the above procedure the decline in area frequency is arrested below 59.0 Hz, that part of the System in the low frequency area should shed an additional 10% of its initial load. If, after five minutes, this action has not returned the area frequency to 59.0 Hz or above, that part of the System shall shed an additional 10% of its remaining load and continue to repeat in five-minute intervals until 59.0 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units.

II. CAPACITY DEFICIENCY PROGRAM

A. PURPOSE

To provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power (AEP)East/PJM Eastern System in the event of a capacity deficiency.

B. CRITERIA

The goals of AEP areis to safely and reliably operate the interconnected network in order to avoid widespread system outages as a consequence of a major disturbance. Precautionary procedures including maintaining Daily Operating Reserves, as specified in ECAR document 2, and PJM Manual M13, will assist in avoiding serious emergency conditions such as system separation and operation at abnormal frequency. However, adequate Daily Operating Reserves cannot always be maintained, so the use of additional emergency measures may be required. A Capacity Deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements.

C. AEP EAST/PJM PROCEDURES

(note: the following section contains excerpts from PJM Manual – M13)

OVERVIEW

PJM is responsible for determining and declaring that an Emergency is expected to exist, exists, or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM Members as necessary to manage, allocate, or alleviate an emergency.

- PJM RTO Reserve Deficiencies — If PJM determines that PJM-scheduled resources available for an Operating Day in combination with Capacity Resources operating on a self-scheduled basis are not sufficient to maintain appropriate reserve levels for the PJM RTO, PJM performs the following actions: T
- Recalls energy from Capacity Resources that otherwise deliver to loads outside the Control Area and dispatches that energy to serve load in the Control Area.
- Purchases capacity or energy from resources outside the Control Area. PJM uses its best efforts to purchase capacity or energy at the lowest prices available at the time such capacity or energy is needed. The price of any such capacity or energy is not considered in determining Locational Marginal Prices in the PJM Energy Market. The cost of capacity or energy is allocated among the Market Buyers as described in the PJM Manual for Operating Agreement Accounting (M-28)

The AEP System Control Center will be referred to as SCC and the AEP Production Optimization Group will be referred to as POG.

(Cont'd on Sheet No. 3-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP EAST/PJM PROCEDURES (cont'd)

CAPACITY SHORTAGES

PJM is responsible for monitoring the operation of the PJM RTO, for declaring the existence of an Emergency, and for directing the operations of the PJM Member as necessary to manage, alleviate, or end an Emergency. PJM also is responsible for transferring energy on the PJM Members behalf to meet an Emergency. PJM is also responsible for agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an Emergency.
Exhibit 1 illustrates that there are three general levels of emergency actions for capacity shortages:

- alerts
- warnings
- actions

ALERTS

The intent of the alerts is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO. All alerts and cancellation thereof are broadcast on the "ALL-CALL" system and posted to selected PJM web sites to assure that all members receive the same information.
Alerts are issued in advance of a scheduled load period to allow sufficient time for members to prepare for anticipated initial capacity shortages.

Maximum Emergency Generation Alert
The purpose of the Maximum Emergency Generation Alert is to provide an early alert that system conditions may require the use of the PJM emergency procedures. It is implemented when Maximum Emergency Generation is called into the operating capacity.

Primary Reserve Alert
The purpose of the Primary Reserve Alert is to alert members of the anticipated shortage of operating reserve capacity for a future critical period. It is implemented when estimated operating reserve capacity is less than the forecast primary reserve requirement.

Voltage Reduction Alert
The purpose of the Voltage Reduction Alert is to alert members that a voltage reduction may be required during a future critical period. It is implemented when the estimated operating reserve capacity is less than the forecast spinning reserve requirement.

Voluntary Customer Load Curtailment Alert
The purpose of the Voluntary Customer Load Curtailment Alert is to alert members of the probable future need to implement a voluntary customer load curtailment. It is implemented whenever the estimated operating reserve capacity indicates a probable future need for voluntary customer load curtailment.

Warnings

Warnings are issued during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO. All warnings and cancellations are broadcasted on the "ALL-CALL" system and posted to selected PJM web sites to assure that all members receive the same information.

Primary Reserve Warning
The purpose of the Primary Reserve Warning is to warn members that the available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve capacity is less than the primary reserve requirement, but greater than the spinning reserve requirement, after all available secondary reserve capacity (except restricted maximum emergency capacity) is brought to a primary reserve status and emergency operating capacity is scheduled from adjacent systems.

(Cont'd on Sheet 3-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP EAST/PJM PROCEDURES (cont'd)

Voltage Reduction Warning & Reduction of Non-Critical Plant Load
The purpose of the Voltage Reduction Warning & Reduction of Non-Critical Plant Load is to warn members that the available spinning reserve is less than the Spinning Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required. It is implemented when the available spinning reserve capacity is less than the spinning reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a spinning reserve status and emergency operating capacity is scheduled from adjacent systems.

Manual Load Dump Warning
The purpose of the Manual Load Dump Warning is to warn members of the increasingly critical condition of present operations that may require manually dumping load. It is issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve. The amount of load and the location of areas(s) are specified.

Actions

The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- Loading generation that is restricted for reasons other than cost
- Recalling non-capacity backed off-system sales
- Purchasing emergency energy from participants / surrounding pools
- Load relief measures

The procedures to be used under these circumstances are described in the general order in which they are applied. Due to system conditions and the time required to obtain results, PJM dispatcher may find it necessary to vary the order of application to achieve the best overall system reliability. Issuance and cancellation of emergency procedures are broadcast over the "ALL-CALL" and posted to selected PJM web sites. Only affected systems take action. PJM dispatcher broadcasts the current and projected PJM RTO status periodically using the "ALL-CALL" during the extent of the implementation of the emergency procedures.

Maximum Emergency Generation
The purpose of the Maximum Emergency Generation is to increase the PJM RTO generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the highest incremental cost level.

Load Management Curtailments (ALM)

Steps 1 and 2 (PJM Control)
The purpose of the Load Management Curtailments, Steps 1 and 2, is to provide additional load relief by using PJM controllable load management programs. Steps 1 and 2 are differentiated only by the expected time to implement. Load relief is required after initiating Maximum Emergency Generation.

Step 1: Short Time Frame to Implement (1 Hour or Less)

- PJM dispatcher requests members to implement Load Management Curtailment, Step 1.

Step 2: Long Time Frame To Implement (Greater Than 1 Hour)

- PJM dispatcher requests members to implement Load Management Curtailment, Step 2.

Steps 3 and 4 (SCC Control)
The purpose of the Local Control Center Programs of Load Management Curtailments, Steps 3 and 4, is to provide additional load relief by requesting use of Local Control Center load management programs.

(Cont'd on Sheet No. 3-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Actions (cont'd)

Load Reduction Program
The purpose of the Load Reduction Action is to request end-use customers to reduce load during emergency conditions.

Voltage Reduction
The purpose of Voltage Reduction during capacity deficient conditions is to reduce load to provide a sufficient amount of reserve to maintain tie flow schedules and preserve limited energy sources. A curtailment of non-essential building load is implemented prior to or at this same time as a Voltage Reduction Action. It is implemented when load relief is still needed to maintain tie schedules.

Note: Voltage reductions can also be implemented to increase transmission system voltage.

Note: Curtailment of non-essential building load may be implemented prior to, but not later than, the same time as a voltage reduction.

Curtailment of Non-Essential Building Load
The purpose of the Curtailment of Non-Essential Building Load is to provide additional load relief, to be expedited prior to, but no later than the same time as a voltage reduction.

Voluntary Customer Load Curtailment
The purpose of the Voluntary Customer Load Curtailment (VCLC) is to provide further load relief. It is implemented when the estimated peak load minus the relief expected from curtailment of non-essential building load and a 2.5% - 5% voltage reduction is greater than operating capacity.

PJM/SCC – Public Appeal to conserve electricity usage

Manual Load Dump
The purpose of the Manual Load Dump is to provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions. It is implemented when the PJM RTO cannot provide adequate capacity to meet the PJM RTO's load or critically overloaded transmission lines or equipment cannot be relieved in any other way and/or low frequency operation occurs in the PJM RTO, parts of the PJM RTO, or PJM RTO and adjacent Control Areas that may be separated as an island.

Addendum to Manual Load Dump Procedures

AEP understands that PJM intends to implement these curtailment protocols consistent with the agreements that PJM entered into in Kentucky and Virginia, in Stipulations approved by the Kentucky Public Service Commission and Virginia State Corporation Commission (with modifications) in Case No. 2002-00475 and Case No. PUE-2000-00550, respectively.

Capacity Deficiency Summary

A summary of the emergency alerts, warning and actions, together with the typical sequence and the method of communication, are presented in the following Table III-2 on Tariff Sheet No. 3-6.

(Cont'd on Sheet No. 3-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

		Communications	Description	
Alert	Maximum Emergency Generation	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC/POG review scheduled or actual maintenance affecting capacity or critical transmission to determine if it can be deferred or cancelled	**EEA 1**
	Primary Reserve	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	(Same as above)	
	Voltage Reduction	PJM-SCC via All-Call SCC-TDC	SCC/TDC to identify stations for Voltage Reduction	
	Voluntary Customer Load Curtailment	PJM-POG via All-Call PJM-SCC via All-Call	Not Applicable	
Warning	Primary Reserve	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC/POG ensure that all deferrable maintenance or testing affecting capacity or critical transmission is halted.	
	Voltage Reduction & Reduction of Non-Critical Plant Load	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC to inform TDC to man Voltage Reduction Stations & prepare for Voltage Reduction	POG to reduce plant load. (See Table III-4)
	Manual Load Dump	PJM-SCC via All-Call SCC– POG-Environmental Services SCC-TDC-DDC	Lifting of Environmental Restrictions (See Table III-5)	Manual & Automatic Load Shedding
		Make preparations for a Public Appeal if one becomes necessary.	Obtain permission to exceed opacity limits Obtain permission to exceed heat input limits Obtain permission to exceed river temperature limits	SCC/TDC will review local computer procedures and man manual load shedding stations
Action	Maximum Emergency Generation	PJM-POG via All-Call PJM-SCC via All-Call	Supplemental Oil & Gas Firing; Operate Generator Peakers; Emergency Hydro; Extra Load Capability	See Table III-3
	Load Management Curtailment (ALM)	PJM-SCC via All-Call SCC - POG	Step 3 – 1267 Mws – 1 hr, 249 Mws – 2 hr	**EEA 2 (DOE Report)**
	Load Reduction Program	PJM-SCC via All-Call	Not Applicable	
	Voltage Reduction	PJM-SCC via All-Call SCC –TDC & SCC - POG	Initiate Voltage Reduction - AEP/PJM – 64 Mws	
	Curtailment of Non-Essential Building Load	PJM-POG via All-Call PJM-SCC via All-Call SCC- Building Services	Initiate curtailment of AEP building load – 4.4 Mws	Issued approx. same time as Voltage Reduction
	Voluntary Customer Load Curtailment	PJM-POG via All-Call PJM-SCC via All-Call	Not Applicable	**EEA 3 (DOE Report)**
	Public Appeal (may be issued at any stage of the Action items)	SCC – Corporate Communications	Radio and TV alert to general public	2% of AEP Internal Load
		SCC – Customer Services SCC - POG	Call to Industrial and Commercial Customers	1276 Mws - 1 hr + 320 Mws - 2 hr
		SCC - TDC	Municipal and REMC Customers	7% of Cust. Load
	Manual Load Dump	PJM-SCC via All-Call SCC-POG-Environmental Services SCC-TDC-DDC	PJM Allocation based on deficient zones	
			Lift Environmental Restrictions on units	(regains curtailed generation)
			Selected distribution customers (manual load curtailment)	Execute MLD

(Cont'd on Sheet No.3-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Energy Emergency Alert Levels (reference NERC Appendix 5C)

1. Alert 1 - All available resources in use.

   Circumstances:
   - Control Area, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 - Load management procedures in effect.

   Circumstances:
   - Control Area, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.

   - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
     - Voltage reduction
     - Emergency Curtailable Service
     - Public appeals to reduce demand
     - Interruption of non-firm end use loads in accordance with applicable contracts, for emergency, not economic reasons
     - Demand-side management
     - Utility load conservation measures

   - During Alert 2, The Reliability Coordinators, Control Areas, and Energy Deficient Entities and AEP have the following responsibilities:

     2.1 Notifying other Control Areas and Market Participants.

     2.2 Declaration Period. The Energy Deficient Entity shall update the Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated.

     2.3 Share information on resource availability.

     2.4 Evaluating and mitigating transmission limitations.
     2.4.1 Notification of ATC adjustments.
     2.4.2 Availability of generation redispatch options.
     2.4.3 Evaluating impact of current Transmission Loading Relief events.
     2.4.4 Initiating inquiries on reevaluating Operating Security Limits.

     2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

     2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of available resources. This includes but is not limited to:

     2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

(Cont'd on Sheet 3-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Energy Emergency Alert Levels (reference NERC Appendix 5C) (Cont'd)

2.6.2 Purchases made regardless of cost. All firm and non=firm purchases have been made regardless of cost.

2.6.2 Non-firm sales recalled and contractually interruptible loads and DSM curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and Demand-side Management activated within provisions of the agreements.

2.6.3 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity AEP is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 - Firm load interruption imminent or in progress.

Circumstances:

- Control Area or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2.

3.2 Declaration Period. The Energy Deficient Entity shall update the Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated.

3.3 Use of Transmission short-time limits.

3.4 Reevaluating and revising Operating Security Limits.

3.4.1 AEP Energy Deficient Entity obligations. The deficient Control Area or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use his best efforts to ensure that revising Operating Security Limits would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency Operating Security Limits, the Control Area Coordinator Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the Alert.

3.5.1 Notification of other parties. Notifications will be made via Oasis and the RCIS.

3.6 Reporting. Any time an Alert 3 is declared, the Control Area Coordinator Energy Deficient Entity shall complete the report listed in NERC Appendix 9B, Section C and submit this report to its respective Reliability Coordinator within two business days of downgrading or termination of the Alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC web site. The Reliability Coordinator shall present this report to the appropriate NERC Sub-committee Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of his Reliability Coordinator that the EEA be terminated.

4.1 Notification.

(Cont'd on Sheet No. 3-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM

III. ENERGY EMERGENCY CONTROL PROGRAM

A. INTRODUCTION

The purpose of this plan is to provide for the reduction of the consumption of electric energy on the American Electric Power Company System in the event of a severe coal fuel shortage, such as might result from a general strike, or severe weather.

B. PROCEDURES

In the event of a potential severe coal shortage, such as one resulting from a general coal strike, the following steps will be implemented. These steps will be carried out to the extent permitted by contractual commitments or by order of the regulatory authorities having jurisdiction.

A. To be initiated when system fuel supplies are decreased to 70% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Optimize the use of non-coal-fired generation to the extent possible.

2. For individual plants significantly under 750% of normal minimum target days' supply, review the prudence of modifying economic dispatching procedures to conserve coal.

3. If necessary discontinue all economy sales to neighboring utilities.

4. Curtail the use of energy in company offices, plants, etc., over and above the reductions already achieved by current in-house conservation measures.

B. To be initiated when system fuel supplies are decreased to 60% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Substitute the use of oil for coal, as permitted by plant design, oil storage facilities, and oil availability.

2. Discontinue all economy and short-term sales to neighboring utilities.

3. Limit emergency deliveries to neighboring utilities to situations where regular customers of such utilities would otherwise be dropped or where the receiving utility agrees to return like quantities of energy within 14 days.

4. Curtail electric energy consumption by customers on Interruptible contracts to a maximum of 132 hours of use at contract demand per week.

5. Purchase energy from neighboring systems to the extent practicable.

6. Purchase energy from industrial customers with generation facilities to the extent practicable.

7. Through the use of news media and direct consumer contact, appeal to all customers (retail as well as wholesale) to reduce their nonessential use of electric energy as much as possible, in any case by at least 25%.

8. Reduce voltage around the clock to the extent feasible.

9. The Company will advise customers of the nature of the mandatory program to be introduced in C below, through direct contact and mass media, and establish an effective means of answering specific customer inquiries concerning the impact of the mandatory program on electricity availability.

(Cont'd on Sheet 3-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM(Cont'd)

III. ENERGY EMERGENCY CONTROL PROGRAM(Cont'd)

B. PROCEDURES (Cont'd)

C. To be initiated -- in the order indicated below -- when system fuel supplies are decreased to 50% of normal target days' operation of coal-fired generation plants and a continued downward trend in coal stocks is anticipated:

1. Discontinue emergency deliveries to neighboring utilities unless the receiving utility agrees to return like quantities of energy within seven days.

2. Request all customers, retail as well as wholesale, to reduce their nonessential use of electric energy by 100%.

3 Request, through mass communication media, curtailment by all other customers a minimum of 15% of their electric use. These uses include lighting, air-conditioning, heating, manufacturing processes, cooking, refrigeration, clothes washing and drying and any other loads that can be curtailed.

4. All customers will be advised of the mandatory program specified below in D.

D. To be initiated when system fuel supplies are decreased to 40% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Implement procedures for curtailment of service to all customers to a minimum service level that is not greater than that required for protection of human life and safety, protection of physical plant facilities and employees' security. This step asks for curtailment of the maximum load possible without endangering life, safety and physical facilities.

2. All customers will be advised of the mandatory program specified below in E.

E. To be initiated when system fuel supplies are decreased to 30% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

Implement procedures for interruption of selected distribution circuits on a rotational basis, while minimizing – to the extent practicable – interruption to facilities that are essential to the public health and safety. (See Section II, Step 14.)

F. The Energy Emergency Control Program will be terminated when:

1. The AEP System's remaining days of operation of coal-fired generation is at least 40% of normal target days' operation, and
2. Coal deliveries have been resumed, and
3. There is reasonable assurance that the AEP System's coal stocks are being restored to adequate levels.

With regard to mandatory curtailments identified in Items C, D, and E above, the Company proposes to monitor compliance after the fact. A customer exceeding his electric allotment would be warned to curtail his usage or face, upon continuing noncompliance and upon one day's actual written notice, disconnection of electric service for the duration of the energy emergency.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

STANDARD NOMINAL VOLTAGES

The voltage available to any individual customer shall depend upon the voltage of the Company's lines serving the area in which customer is provided service.

Electric service provided under the Company's rate schedules will be 60 hertz alternating current delivered from various load centers at nominal voltages and phases as available in a given location as follows:

SECONDARY DISTRIBUTION VOLTAGES.

Residential Service

Single phase 120/240 volts three wire or 120/208 volts three wire on network system.

General Service - All Except Residential

Single-phase 120/240 volts three wire or 120/208 volts three wire on network system. Three-phase 120/208 volts four wire on network system, 120/240 volts four wire, 240 volts three wire, 480 volts three wire and 277/480 volts four wire.

PRIMARY DISTRIBUTION VOLTAGES.

The Company's primary distribution voltage levels at load centers are 2,400; 4,160Y; 7,200; 12,470Y, 19,900 and 34,500Y.

SUBTRANSMISSION LINE VOLTAGES.

The Company's sub transmission voltage levels are 19,900; 34,500; 46,000; and 69,000.

TRANSMISSION LINE VOLTAGES.

The Company's transmission voltage levels are 138,000; 161,000; 345,000; and 765,000.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF F.A.C.
(Fuel Adjustment Clause)

APPLICABLE.

To Tariffs R.S.,Experimental R.S.T.O.D. 2, R.S.-L.M.-T.O.D. R.S.-T.O.D., S.G.S., S.G.S.-T.O.D.,M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S. T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L. T

RATE.

1. The fuel clause shall provide for periodic adjustment per kwh of sales equal to the difference between the fuel costs per kwh of sales in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F\,(m)}{S\,(m)} - \frac{F\,(b)}{S\,(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below:

2. F(b)/S(b) shall be so determined that on the effective date of the Commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero (0).

3. Fuel costs (F) shall be the most recent actual monthly cost of:

   a. Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of the fuel related substitute generation, plus

   b. The actual identifiable fossil and nuclear fuel costs [if not known--the month used to calculate fuel (F), shall be deemed to be the same as the actual unit cost of the Company generation in the month said calculations are made. When actual costs become known, the difference, if any, between fuel costs (F) as calculated using such actual unit costs and the fuel costs (F) used in that month shall be accounted for in the current month's calculation of fuel costs (F)] associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

   c. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

   d. The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

   e. All fuel costs shall be based on weighted average inventory costing.

4. Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacturer, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel costs of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel costs (F) in subsection (3)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(Cont'd on Sheet No. 5-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 5-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 5-2

TARIFF F.A.C. (Cont'd)
(Fuel Adjustment Clause)

5. Sales (S) shall be all kwh's sold, excluding intersystem sales. Where, for any reason billed system sales cannot be coordinated with the fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) intersystem sales referred to in subsection (3)(d) above, less (vi) total system loss. Utility used energy shall not be excluded in the determination of sales (S).

6. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts or Public Utilities and Licensees.

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options or similar such documents, and all amendments and modifications thereof related to the procurement of fuel supply and purchased power. Incorporation by reference is permissible. Any changes in the documents, including price escalations, or any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. Where fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges, which are unreasonable, shall be disallowed and may result in the suspension of the fuel adjustment clause. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by this regulation.

8. Any tariff filing which contains a fuel clause shall conform that clause with this regulation within three (3) months of the effective date of this regulation. The tariff filing shall contain a description of the fuel clause with detailed cost support.

9 The monthly fuel adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

10. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884.

11. At six (6) month intervals, the Commission will conduct public hearings on a utility's past fuel adjustments. The Commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustment it finds unjustified due to improper calculation or application of the charges or improper fuel procurement practice.

12. Every two (2) years following the initial effective date of each utility fuel clause, the Commission in a public hearing will review and evaluate past operations of the clause, disallow improper expenses, and to the extent appropriate, reestablish the fuel clause charge in accordance with Subsection 2.

13. Resulting cost per kilowatt-hour in June 2008 to be used as the base cost in Standard Fuel Adjustment Clause is :

Fuel -	June 2008 =	$16,138,627	= $ 0.02840/kwh
Sales	June 2008	568,162,000	

This, as used in the Fuel Adjustment Clause, is 2.840¢ per kilowatt-hour.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.
(Residential Service)

AVAILABILITY OF SERVICE.

Available for full domestic electric service through 1 (one) meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

RATE. (Tariff Codes 015, 017, 022)

Service Charge..	$16.00 per month	I
Energy Charge:	9.035¢ per KWH	I

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule. T T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule N

(Cont'd on Sheet No. 6-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 6-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 6-2

TARIFF R.S. (Cont'd)
(Residential Service)

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

VOLUNTEER FIRE DEPARTMENTS (Tariff Code 024) N

Volunteer Fire Departments may qualify pursuant to KRS 278.172 for this tariff but will be required to provide a completed Form 990 and update it annually. N

(Cont'd on Sheet No. 6-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.(Cont'd)
(Residential Service)

STORAGE WATER HEATING PROVISION.

This provision is withdrawn except for the present installations of current customers receiving service hereunder at premises served prior to April 1, 1997.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

Tariff Code

012 (a) For Minimum Capacity of 80 gallons, the last 300 KWH of use in any month shall be billed at 4.940¢ per KWH.

013 (b) For Minimum Capacity of 100 gallons, the last 400 KWH of use in any month shall be billed at 4.940¢ per KWH.

014 (c) For Minimum Capacity of 120 gallons or greater, the last 500 KWH of use in any month shall be billed at 4.940¢ per KWH.

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00PM to 7:00AM for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, the Fuel Adjustment Clause, the System Sales Clause, the Demand-Side Management Clause, the Asset Transfer Rider, Big Sandy Retirement Rider, Big Sandy 1 Operation Rider, the Purchase T
Power Adjustment, the Environmental Surcharge, the Capacity Charge, the P.J.M. Rider, the Kentucky Economic T
Development Rider, the Residential HEAP Charge, NERC Compliance and Cybersecurity Rider factors as stated in the T
above monthly rate.

(Cont'd. on Sheet No. 6-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.
(Residential Service)

LOAD MANAGEMENT WATER-HEATING PROVISION. (Tariff Code 011)

For residential customers who install a load management water-heating system which consumes electrical energy during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at 5.216¢ per KWH. T I

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

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

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

This provision is subject to the Service Charge, the Fuel Adjustment Clause, the System Sales Clause, the Demand-Side Management Clause, the Asset Transfer Rider, the Purchase Power Adjustment, the Environmental Surcharge, the Capacity Charge and the Residential HEAP Charge factors as stated in the above monthly rate.

SPECIAL TERMS AND CONDITIONS.

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

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

The Company shall have the option of reading meters monthly or bimonthly and rendering bills accordingly. When bills are rendered bimonthly, the minimum charge and the quantity of KWH in each block of the rates shall be multiplied by two.

Pursuant to 807 KAR 5:041, Section 11, paragraph (1), of Public Service Commission Regulations, the Company will make an extension of 1,000 feet or less to its existing distribution line without charge for a prospective permanent residential customer served under this R.S. Tariff. Pursuant to 807 KAR 5:041 Section 12 extensions of up to 150 feet for a mobile home are provided without charge. N

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement.

(Cont'd on Sheet No. 6-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-L.M.-T.O.D.
(Residential Service Load Management Time-of-Day)

AVAILABILITY OF SERVICE.

Available to customers eligible for Tariff R.S. (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this tariff shall be metered through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods. T

RATE. (Tariff Codes 028, 030, 032, 034)

Service Charge...$ 18.70 per month I
Energy Charge:
All KWH used during on-peak billing period............................ 13.879¢ per KWH I
All KWH used during off-peak billing period............................. 5.216¢ per KWH I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

CONSERVATION AND LOAD MANAGEMENT CREDIT.

For the combination of an approved electric thermal storage space heating system and water heater, both of which are designed to consume electrical energy only between the hours of 9:00P.M. and 7:00A.M. for all days of the week, each residence will be credited 0.745¢ per KWH for all energy used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule. T

(Cont'd. on Sheet 6-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-L.M.-T.O.D. (Cont'd)
(Residential Service Load Management Time-of-Day)

ASSET TRANSFER RIDER

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet Nos. 38-1 thru 38-2 of this Tariff Schedule. N

BIG SANDY 1 OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet No. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1thru 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 and 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider factor per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 thru 24-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 6-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-L.M.-T.O.D. (Cont'd)
(Residential Service Load Management Time-of-Day)

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers' bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 thru 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

SEPARATE METERING PROVISION.

Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be $3.85 per month. I

SPECIAL TERMS AND CONDITIONS.

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

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

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

(Cont'd on Sheet 6-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

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

AVAILABILITY OF SERVICE.

Available for residential electric service through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits. Availability is limited to the first 1,000 customers applying for service under this tariff. T

RATE. (Tariff Code 036)

Service Charge.. $ 18.70 per month I
Energy Charge:
All KWH used during on-peak billing period............................. 13.879¢ per KWH I
All KWH used during off-peak billing period............................ 5.216¢ per KWH I

For the purpose of this tariff, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00P.M. to 7:00A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bill computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment actor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N | N

BIG SANDY RETIREMENT RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet Nos. 38-1 thru 38-2 of this Tariff Schedule. N | N

(Cont'd on Sheet No. 6-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

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

BIG SANDY 1 OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 thru 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers' bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 6-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S. - T.O.D. (Cont'd)
(Residential Service Time-of-Day)

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

SPECIAL TERMS AND CONDITIONS.

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

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

(Cont'd on Sheet No. 6-11)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S. – T.O.D.2
(Experimental Residential Service Time-of-Day 2)

AVAILABILITY OF SERVICE.

Available on a voluntary, experimental basis to individual residential customers for residential electric service through a multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff. T

RATE. (Tariff Code 027)

Service Charge .... $18.70 per month I

Energy Charge:

All KWH used during Summer on-peak billing period .... 10.885¢ per KWH R

All KWH used during Winter on-peak billing period .... 12.132¢ per KWH R

All KWH used during off-peak billing period .... 8.309¢ per KWH I

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months	On-Peak	Off-Peak
Approximate Percent (%) Of Annual Hours	16%	84%
Winter Period:		
November 1 to March 31	7:00 A.M. to 11:00 A.M. 6:00 P.M. to 10:00 P.M.	11:00 AM. to 6:00 P.M. 10:00 P.M. to 7:00 A.M.
Summer Period:		
May 15 to September 15	Noon to 6:00 P.M.	6:00 P.M. to Noon
All Other Calendar Periods	None	Midnight to Midnight

NOTE: All KWH consumed during Saturday and Sunday are billed at the off-peak level.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

(Cont'd on Sheet No. 6-12)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-T.O.D.2 (Cont'd)
(Experimental Residential Service Time-of-Day 2)

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment actor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-1of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

(Cont'd on Sheet No. 6-13)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-T.O.D.2 (Cont'd)
(Experimental Residential Service Time-of-Day 2)

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

SPECIAL TERMS AND CONDITIONS.

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

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

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

AVAILABILITY OF SERVICE.

Available for general service to customers with average monthly demands less than 10 KW and maximum monthly demands of less than 15 KW (excluding the demand served by the Load Management Time-of-Day provisions). Service will be provided at Secondary voltage metering only. N

Customers not meeting the requirements for availability under this tariff will only be permitted to continue service under this tariff at the premise occupied for continuous service beginning no later than January 22, 2015. N

RATE. (Tariff Codes 211, 212)

Service Charge...	$19.50 per month	I
Energy Charge:		
First 500 KWH per month..	11.500¢ per KWH	R
All Over 500 KWH per month..	7.057¢ per KWH	R

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rate set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1through 38-2 of this Tariff Schedule. N

(Cont'd on Sheet No. 7-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.G.S. (Cont'd.)
(Small General Service)

BIG SANDY 1 OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

(Cont'd. on Sheet 7-3)

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.G.S. (Cont'd.)
(Small General Service)

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE. (Tariff Code 225)

Service Charge	$19.50 per month	I
Energy Charge:		
All KWH used during on-peak billing period	13.755¢ per KWH	R
All KWH used during off-peak billing period	5.216¢ per KWH	I

OPTIONAL UNMETERED SERVICE PROVISION.

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

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

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

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at the following rates:

RATE. (Tariff Codes 204 (Metered), 213 (Unmetered))

Customer Charge	$15.50 per month	I
Energy Charge:		
First 500 KWH per month	11.500¢ per KWH	R
All Over 500 KWH per month	7.057¢ per KWH	R

TERM OF CONTRACT.

The Company shall have the right to require contacts for a period of one (1) year or longer.

SPECIAL TERMS AND CONDITIONS.

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

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

(Cont'd on Sheet No. 7-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission
In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.G.S. – T.O.D.
(~~Experimental~~ Small General Service Time-of-Day Service)

AVAILABILITY OF SERVICE.

Available on a voluntary, basis for general service to customers being served at secondary distribution voltage with one single-phase, multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff. T

Customers not meeting the requirements for availability under this tariff will only be permitted to continue service under this tariff at the premise occupied for continuous service beginning no later than January 22, 2015. N

RATE. (Tariff Code 227)

Service Charge	$19.50 per month	I
Energy Charge:		
All KWH used during Summer on-peak billing period	11.126¢ per KWH	R
All KWH used during Winter on-peak billing period	12.020¢ per KWH	R
All KWH used during off-peak billing period	8.476¢ per KWH	R

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months	On-Peak	Off-Peak
Approximate Percent (%) Of Annual Hours	16%	84%
Winter Period: November 1 to March 31	7:00 A.M. to 11:00 A.M. 6:00 P.M. to 10:00 P.M.	11:00 A.M. to 6:00 P.M. 10:00 P.M. to 7:00 A.M.
Summer Period: May 15 to September 15	Noon to 6:00 P.M.	6:00 P.M. to Noon
All Other Calendar Periods	None	Midnight to Midnight

NOTE: All KWH consumed during weekends are billed at the off-peak level.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

(Cont'd on Sheet No. 7-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.G.S.-T.O.D. (Cont'd)
(Small General Service Time-of-Day)

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 and 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 7-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

(Small General Service Time-of-Day) T

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule N

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission
In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 8- 1
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 8- 1

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

AVAILABILITY OF SERVICE.

Available for general service to customers with average monthly demands greater than 10 KW or maximum monthly demands greater than 15 KW, but not more than 100 KW (excluding the demand served by the Load Management Time-of-Day provision). Except as provided below, customers receiving service on or before January 22, 2015 at a secondary voltage and with average monthly demand below 10 KW will be served under the S.G.S. tariff. N

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	
Tariff Code	215, 216, 218	217, 220	236	
Service Charge per Month	$ 19.50	$ 50.00	$ 364.00	I I I
Demand Charge per KW	$ 2.05	$ 1.99	$ 1.96	I I I
Energy Charge:				
KWH equal to 200 times KW of monthly billing demand	10.072¢	9.245¢	8.538¢	I I I
KWH in excess of 200 times KW of monthly billing demand	8.639¢	8.270¢	8.018¢	I I I

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by 6 KW. The minimum monthly charge for industrial and coal mining customers contracting for 3-phase service after October 1, 1959 shall be $ 8.55 per KW of monthly billing demand. I

RECREATIONAL LIGHTING SERVICE PROVISION.

Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff M.G.S. customers will also apply to recreational lighting customers except for the Availability of Service.

RATE. (Tariff Code 214)

Service Charge .... $ 19.50 per month I
Energy Charge .... 10.000¢ per KWH I

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule. T T

(Cont'd on Sheet No. 8-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Of Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-Xxxx Dated Xxxxxxxx

TARIFF M.G.S. (Cont'd.)
(Medium General Service)

ASSET TRANSFER RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY 1 OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rate set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

(Cont'd on Sheet No. 8-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S (Cont'd)
(Medium General Service)

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Energy supplied hereunder will be delivered through not more than one single phase and/or polyphase meter. Customer's demand will be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The minimum monthly billing demand shall not be less than (a) the minimum billing demand of 6 KW, or (b) 60% of the greater of (1) the customer's contract capacity in excess of 100 KW or (2) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

(Cont'd on Sheet No. 8-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S (Cont'd)
(Medium General Service)

LOAD MANAGEMENT TIME-OF-DAY PROVISION. (Tariff Code 223)

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE.

Service Charge	$ 3.85	per month	I
Energy Charge:			
All KWH used during on-peak billing period	$15.757¢	per KWH	I
All KWH used during off-peak billing period	5.491¢	per KWH	I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

TERM OF CONTRACT.

Contracts under this tariff ~~will~~ *may* be required of customers. Contracts under this tariff will be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for periods of longer than 1 (one) year. T T

SPECIAL TERMS AND CONDITIONS.

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

This tariff is also available to Customers having other source of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum demand in KW which the Company might be required to furnish, but no less than 10 KW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point of both their power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

(Cont'd on Sheet No. 8-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S.-T.O.D.
(Medium General Service Time-of-Day)

AVAILABILITY OF SERVICE.

Available for general service to customers with normal maximum demands greater than 10 KW but not more than 100 KW. Availability is limited to the first 500 customers applying for service under this tariff.

RATE. (Tariff Code 229)

Service Charge	$ 19.50 per month	I
Energy Charge: All KWH used during on-peak billing period	$ 15.757¢ per KWH	I
All KWH used during off-peak billing period	5.491¢ per KWH	I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday.
The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

(Cont'd on Sheet No. 8-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S.-T.O.D. (Cont'd)
(Medium General Service Time-of-Day)

BIG SANDY 1 OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 8-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S.-T.O.D. (Cont'd)
(Medium General Service Time-of-Day)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

SPECIAL TERMS AND CONDITIONS.

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

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

AVAILABILITY OF SERVICE.

Available for general service to customers with normal maximum demands greater than 100 KW but not more than 1,000 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE.

	Service Voltage				
	Secondary	Primary	Subtransmission	Transmission	
Tariff Code	240, 242	244, 246	248	250	
Service Charge per Month	$ 85.00	$ 127.50	$ 661.65	$ 661.65	II..
Demand Charge per KW	$ 5.03	$ 4.89	$ 4.83	$ 4.75	IIII
Excess Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46	
Energy Charge per KWH	8.056¢	6.851¢	4.670¢	4.579¢	IIRR

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) N authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N

(Cont'd. On Sheet No. 9-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. (Cont'd.)
(Large General Service)

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY 1 OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of
revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 9-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. (Cont'd)
(Large General Service)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

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

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

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE. (Tariff Code 251)

Service Charge	$ 85.00 per month	I
Energy Charge:		
All KWH used during on-peak billing period	13.164¢ per KWH	I
All KWH used during off-peak billing period	5.471¢ per KWH	I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

(Cont'd on Sheet No. 9-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. (Cont'd)
(Large General Service)

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required. T T

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

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

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

(Cont'd on Sheet No. 9-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. – T.O.D.
(Large General Service – Time of Day)

AVAILABILITY OF SERVICE.

Available for general service customers with normal maximum demands of 100 KW or greater. Customers may continue to qualify for service under this tariff until their 12-month average demand exceeds 1,000 KW. Availability is limited to the first 500 customers applying for service under this tariff.

RATE.

	Service Voltage				
	Secondary	Primary	Subtransmission	Transmission	
Tariff Code	256	257	258	259	
Service Charge per Month	$ 85.00	$ 127.50	$ 661.65	$ 661.65	I I
Demand Charge per KW	$ 10.20	$ 7.35	$ 1.08	$ 1.07	I I I I
Excessive Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46	
On-Peak Energy Charge per KWH	8.481¢	8.187¢	8.098¢	8.002¢	I I I I
Off-Peak Energy Charge per KWH	4.533¢	4.411¢	4.374¢	4.334¢	I I I I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., for all weekdays Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) N authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N

(Cont'd on Sheet No. 9-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. – T.O.D. (Cont'd.)
(Large General Service – Time of Day)

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

(Cont'd on Sheet 9-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. – T.O.D. (Cont'd)
(Large General Service – Time of Day)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional Charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

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

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

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

(Cont'd on Sheet No. 9-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. – T.O.D. (Cont'd)
(Large General Service – Time of Day)

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

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

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

N

TARIFF I.G.S.
(Industrial General Service)

AVAILABILITY OF SERVICE.

Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet normal maximum requirements.

RATE.

	Secondary	Primary	Service Voltage Subtransmission	Transmission
Tariff Code	356	358/370	359/371	360/372
Service Charge per month	$ 276.00	$ 276.00	$ 794.00	$ 1,353.00
Demand Charge per KW				
Of monthly on-peak billing demand	$ 20.69	$ 17.46	$ 10.74	$ 10.45
Of monthly off-peak billing demand	$ 1.13	$ 1.10	$ 1.08	$ 1.07
Energy Charge per KWH	3.398¢	3.279¢	3.242¢	3.204¢

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand .... $0.69/ KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

MINIMUM DEMAND CHARGE.

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	Primary	Subtransmission	Transmission
$22.06/KW	$18.80 /KW	$12.07/KW	$11.76/KW

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule. N

(Cont'd on Sheet No. 10-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF I.G.S.
(Industrial General Service)

N

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.

BIG SANDY RETIREMENT RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule.

BIG SANDY I OPERATION RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule.

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 10-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

N

TARIFF I.G.S.
(Industrial General Service)

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator. N

(Cont'd on Sheet No. 10-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF I.G.S.
(Industrial General Service)

N

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY

The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiples of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

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

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE

T

DATE OF ISSUE: December 22, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

Issued By: JOHN A. ROGNESS III

Title: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

RESERVED FOR FUTURE USE T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power)

AVAILABILITY OF SERVICE.

Available for service to customers who contract for service under one of the Company's interruptible service options. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to 75,000 kW. T

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

CONDITIONS OF SERVICE.

The Company will offer eligible customers the option to receive service from a menu of interruptible power options pursuant to a contract agreed to by the Company and the Customer.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written offer containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet normal maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than 1,000 KW at any delivery point.

RATE. (Tariff Code 321)

Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's rules as capacity for the purpose of the Company's FRR obligation. N

Charges for the service under this tariff will be set forth in the written agreement between the Company and the Customer and will reflect a difference from the firm service rates otherwise available to the Customer.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to he rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

(Cont'd on Sheet No. 12-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 12-2**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 12-2

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the Customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rate set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 and 28-2 of this Tariff Schedule.

(Cont'd on Sheet No. 12-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

TERM OF CONTRACT

The length of the agreement and the terms and conditions of service will be stated in the agreement between the Company and the Customer.

CONFIDENTIALITY

All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807 KAR5:001, Section 7 and the request is granted.

(Cont'd on Sheet No. 12-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

SPECIAL TERMS AND CONDITIONS

Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of Service.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist, the Customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 1,000 KW.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company

TARIFF M.W.
(Municipal Waterworks)

AVAILABILITY OF SERVICE.

Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the Customer on this date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load, which the Company may be required to furnish.

RATE. (Tariff Code 540)

Service Charge .... $ 22.90 per month
Energy Charge:
All KWH Used Per Month .... 8.601¢ per KWH I

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus $ 8.20 per KVA as determined from customer's total connected load. I

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N
|
N

(Cont'd on Sheet No. 13-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.W. (Cont'd)
(Municipal Waterworks)

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 and 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission

(Cont'd on Sheet No. 13-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.W. (Cont'd)
(Municipal Waterworks)

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

PAYMENT.

Bills will be rendered monthly and will be due and payable on or before the due date stated on the bill.

TERM OF CONTRACT.

Contracts under this tariff will be made for not less than (1) one year with self-renewal provisions for successive periods of (1) one year each until either party shall give at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than (1) one year.

SPECIAL TERMS AND CONDITIONS.

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

This tariff is not available to customers having other sources of energy supply.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF O.L.
(Outdoor Lighting)

AVAILABILITY OF SERVICE.

Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable.

RATE.

A. OVERHEAD LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
094		100 watts (9,500 Lumens)	$ 9.65 per lamp	I
113		150 watts (16,000 Lumens)	$ 10.95 per lamp	I
097		200 watts (22,000 Lumens)	$ 13.45 per lamp	I
103		250 watts (28,000 Lumens)	$ 8.10 per lamp	I
098		400 watts (50,000 Lumens)	$ 21.05 per lamp	I
	2.	Mercury Vapor		
093*		175 watts (7,000 Lumens)	$ 10.75 per lamp	I
095*		400 watts (20,000 Lumens)	$ 18.60 per lamp	I

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. POST-TOP LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
111		100 watts (9,500 Lumens)	$ 14.45 per lamp	I
122		150 watts (16,000 Lumens)	$ 23.70 per lamp	I
121		100 watts Shoe Box (9,500 Lumens)	$ 33.50 per lamp	I
120		250 watts Shoe Box (28,000 Lumens)	$ 50.05 per lamp	I
126		400 watts Shoe Box (50,000 Lumens)	$ 44.10 per lamp	I
	2.	Mercury Vapor		
099*		175 watts (7,000 Lumens)	$ 12.30 per lamp	I

*Effective June 29, 2010 and thereafter these lamps are not available for new installations

Company will provide lamp photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits.

(Cont'd on Sheet 14-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

RATE. (Cont'd.)

C. FLOOD LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
107		200 watts (22,000 Lumens)................................	$ 15.00 per lamp	I
109		400 watts (50,000 Lumens)................................	$ 20.80 per lamp	I
	2.	Metal Halide		
110		250 watts (20,500 Lumens)................................	$ 20.10 per lamp	I
116		400 watts (36,000 Lumens)................................	$ 26.60 per lamp	I
131		1000 watts (110,000 Lumens)	$ 67.35 per lamp	I
130		250 watts Mongoose (19,000 Lumens)	$ 25.30 per lamp	I
136		400 watts Mongoose (40,000 Lumens)	$ 30.30 per lamp	I

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

Wood pole..	$ 3.15 per month	I
Overhead wire span not over 150 feet	$ 1.75 per month	I
Underground wire lateral not over 50 feet.......................................	$ 6.90 per month	I
(Price includes pole riser and connections)		

(Cont'd on Sheet No. 14-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule. The monthly kilowatt-hours for Fuel Adjustment Clause, System Sales Clause and the Capacity Charge computations are as follows:

	METAL HALIDE			MERCURY VAPOR		HIGH PRESSURE SODIUM				
	250 WATTS	400 WATTS	1000 WATTS	175 WATTS	400 WATTS	100 WATTS	150 WATTS	200 WATTS	250 WATTS	400 WATTS
JAN	127	199	477	91	199	51	74	106	130	210
FEB	106	167	400	76	167	43	62	89	109	176
MAR	106	167	400	76	167	43	62	89	109	176
APR	90	142	340	65	142	36	53	76	93	150
MAY	81	127	304	58	127	32	47	68	83	134
JUNE	72	114	272	52	114	29	42	61	74	120
JULY	77	121	291	55	121	31	45	65	79	128
AUG	88	138	331	63	138	35	51	74	90	146
SEPT	96	152	363	69	152	39	57	81	99	160
OCT	113	178	427	81	178	45	66	95	116	188
NOV	119	188	449	86	188	48	70	100	122	198
DEC	129	203	486	92	203	52	75	108	132	214
TOTAL	1204	1896	4540	864	1896	484	704	1012	1236	2000

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N N

BIG SANDY I OPERATION RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N N

(Cont'd. on Sheet No. 14-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

OWNERSHIP OF FACILITIES.

All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company.

The Company shall be allowed 3 working days after notification by the customer to replace all burned-out lamps.

TERM OF INITIAL SERVICE.

Term of initial service shall be required for a period of one year. If early termination is requested, the customer will be billed for the remainder of the 12 month period. N

SPECIAL TERMS AND CONDITIONS.

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

The Company shall have the option of rendering monthly or bimonthly bills.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.L.
(Street Lighting)

AVAILABILITY OF SERVICE.

Available for lighting service for all the lighting of public streets, public highways and other public outdoor areas in municipalities, counties, and other governmental subdivisions where such service can be supplied from the existing general distribution systems.

RATE. (Tariff Code 528)

A. Overhead Service on Existing Distribution Poles

1. High Pressure Sodium

100 watts (9,500 lumens)	$ 8.05 per lamp	I
150 watts (16,000 lumens)	$ 9.25 per lamp	I
200 watts (22,000 lumens)	$ 11.45 per lamp	I
400 watts (50,000 lumens)	$ 17.80 per lamp	I

B. Service on New Wood Distribution Poles

1. High Pressure Sodium

100 watts (9,500 lumens)	$ 11.35 per lamp	I
150 watts (16,000 lumens)	$ 12.60 per lamp	I
200 watts (22,000 lumens)	$ 14.60 per lamp	I
400 watts (50,000 lumens)	$ 20.45 per lamp	I

C. Service on New Metal or Concrete Poles*

1. High Pressure Sodium

100 watts (9,500 lumens)	$ 20.95 per lamp	I
150 watts (16,000 lumens)	$ 22.00 per lamp	I
200 watts (22,000 lumens)	$ 28.00 per lamp	I
400 watts (50,000 lumens)	$ 30.45 per lamp	I

*Effective June 29, 2010 and thereafter these lamps are not available for new installations

Lumen rating is based on manufacturer's rated lumen output for new lamps.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule. The monthly kilowatt-hours for Fuel Adjustment Clause, System Sales Clause and the Capacity Charge computations are as follows:

(Cont'd on Sheet No. 15-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.L. (Cont'd.)
(Street Lighting)

FUEL ADJUSTMENT CLAUSE. (Cont'd.)

	HIGH PRESSURE SODIUM			
MONTH	100 WATTS	150 WATTS	200 WATTS	400 WATTS
JAN	51	74	106	210
FEB	43	62	89	176
MAR	43	62	89	176
APR	36	53	76	150
MAY	32	47	68	134
JUNE	29	42	61	120
JULY	31	45	65	128
AUG	35	51	74	146
SEPT	39	57	81	160
OCT	45	66	95	188
NOV	48	70	100	198
DEC	52	75	108	214
TOTAL	484	704	1012	2000

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered. N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

(Cont'd On Sheet No. 15-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.L. (Cont'd.)
(Street Lighting)

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

SPECIAL FACILITIES.

When a customer requests street lighting service which requires special poles or fixtures, underground street lighting, or a line extension of more than one span of approximately 150 feet, the customer will be required to pay, in advance, an aid-to-construction in the amount of the installed cost of such special facilities

PAYMENT.

Bills are due and payable within ten (10) days of the mailing date.

HOURS OF LIGHTING.

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

TERM OF CONTRACT.

Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company may have the right to require contracts for periods of longer than one year if new or additional facilities are required.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C. A. T. V.
(Cable Television Pole Attachment)

AVAILABILITY OF SERVICE.

Available to operators of cable television systems (Operators) furnishing cable television service in the operating area of Kentucky Power Company (Company) for attachments of aerial cables, wires and associated appliances (attachments) to certain distribution poles of Kentucky Power Company.

As used in this Tariff, an "attachment" shall mean the physical connection of (a) a messenger strand supporting the wires, cables or stand-mounted associated facilities and equipment of a cable system or (b) service drops affixed to the pole and located more than one vertical foot away from the point at which the messenger strand is attached to the pole (but not a strand originating or mid-span service drop) or (c) service drops located on a dedicated service, drop or lift pole. An attachment shall consume no more than one foot (1') of vertical space on any distribution pole owned by the Company. N

RATE.

Charge for attachments on a two-user pole .... $ 7.21 per-attachment per year T
Charge for attachments on a three-user pole .... $ 4.47 per attachment per year T

The above rate was calculated in accordance with the following formula:

Weighted Average Bare Pole Cost	x	Usage Factor	x	Carrying Charge	= Rate Per Pole

A two-user pole is a pole being used, by actual occupation or reservation, by the Operator and the Company. A three-user pole is a pole being used by actual occupation or reservation, by the Operator, the Company, and a third party. N

DELAYED PAYMENT CHARGE.

This Tariff is net if account is paid in full within 30 days of date of bill. On all accounts not so paid an additional charge of 5% of the unpaid balance will be made. T

POLE SUBJECT TO ATTACHMENT.

When an Operator proposes to furnish cable television service within the Company's operating area and desires to make attachments on certain distribution poles of Company, Operator shall make written application, on a form furnished by Company, to install attachments specifying the location of each pole in question, the character of its proposed attachments and the amount and location of space desired, and any other information necessary to calculate the transverse and vertical load placed upon the pole as a result of the proposed attachment and any other facilities attached to the pole. Within forty-five (45) days after receipt of the application, Company shall notify Operator whether and to what extent any special conditions will be required to permit the use by Operator of each such pole. Operator shall reimburse Company for any expenses incurred in reviewing such written applications for attachment. Operator shall have a non-exclusive right to use such poles of Company as may be used or reserved for use by Operator and any other poles of Company when brought hereunder in accordance with the procedure hereinafter provided. Company shall have the right to grant, by contract or otherwise to others rights or privileges to use any poles of the Company and Company shall have the right to continue and extend any such rights or privileges heretofore granted. All poles shall be and remain the property of Company regardless of any payment by Operator toward their cost and Operator shall, except for the rights provided hereunder, acquire no right, title or interest in or to any such pole. T

(Cont'd on Sheet No. 16-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

STANDARDS FOR INSTALLATION.

All attachments and associated equipment of Operator (including without limitation, power supplies) shall be installed in a manner satisfactory to Company and so as not to interfere with the present or any future use which Company may desire to make of the poles covered by this Tariff. All such attachments and equipment shall be installed and at all times maintained by Operator so as to comply at least with the minimum requirements of the National Electrical Safety Code and any other applicable regulations or codes promulgated by state, local or other governmental authority having jurisdiction there over. Power supply apparatus having as its largest dimension more than sixteen inches must be placed on a separate pole to be installed by Operator. Operator shall take necessary precautions by the installation of protective equipment or other means, to protect all persons and property of all kinds against injury or damage occurring by reason of Operator's attachments.

POLE INSTALLATION OR REPLACEMENT; REARRANGEMENTS; GUYING.

In any case Operator proposes to install attachments on a pole to be erected by Company in a new location, and to provide adequate space or strength to accommodate such attachments (either at the request of Operator to comply with the aforesaid codes and regulations) such pole must, in Company's judgment, be taller and/or stronger than would be necessary to accommodate the facilities of Company and of other persons who have previously indicated that they desire to make attachments on such pole or with whom Company has an agreement providing for joint or share ownership of poles, the cost of such extra height and/or strength shall be paid to Company by Operator. Such cost shall be the difference between the cost in place of the new pole and the current cost in place of a pole considered by Company to be adequate for the facilities of Company and the attachments of such other persons.

Where in Company's judgment a new pole must be erected to replace an existing pole solely to adequately provide for Operator's proposed attachments, Operator agrees to pay Company for the entire cost of the new pole necessary to accommodate the existing facilities on the pole and Operator's proposed attachments, plus the cost of removal of the in-place pole, minus the salvage value, if any, of the removed pole. Title to the new pole shall remain with the Company. Operator shall also pay to Company and to any other owner of existing attachments on the pole the cost of removing each of their respective facilities or attachments from the existing pole and reestablishing the same or like facilities or attachments on the newly-installed pole.

If Operator's desired attachments can be accommodated on existing poles of Company by rearranging facilities of Company thereon of any other person, or if because of Operator's proposed attachments it is necessary for Company to rearrange its facilities on any pole not owned by it, then in any such case, Operator shall reimburse Company and any such other person for the respective expense incurred in making such rearrangement.

If because of the requirements of its business, Company proposed to replace an existing pole on which Operator has any attachment, or Company proposed to change the arrangements of its facilities on any such pole in such manner as to necessitate a rearrangement of Operator's attachment, or if as a result of any inspection of Operator's attachments Company determines that any such attachments are not in accordance with applicable codes or the provisions of this Tariff or are otherwise hazards Company shall give Operator not less than 48 hours notice of such proposed replacement or change, or any such violation or hazard, unless an emergency requires a shorter period. In such event, Operator shall at its expense relocate, rearrange or modify its attachments at the time specified by Company. If Operator fails to do so, or if any such emergency makes notice impractical, Company shall perform such relocation or rearrangement and Operator shall reimburse Company for the reasonable cost thereof.

Any additional guying or anchors required by reason of the attachments of Operator shall be provided at the expense of Operator and shall meet the requirements of all applicable codes or regulations and Company's generally applicable guying standards.

(Cont'd on Sheet No. 16-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

POLE INSPECTION.

Company may make periodic inspections, as conditions may warrant, for the purpose of determining compliance with the provisions of this Tariff. Company reserves the right to inspect each new or proposed installation of Operator on Company's poles. In addition, Company's right to make any inspections and any inspection made pursuant to such right shall not relieve Operator of any responsibility, obligation or liability assumed under this Tariff.

UNAUTHORIZED ATTACHMENTS.

Operator shall make no attachment to or other use of any pole of Company or any facilities of Company thereon, except as authorized. The company reserves the right to make periodic inspections. Should such unauthorized attachment or use be made, Operator shall pay to the Company on demand two times the charges and fees, including but not limited to, any payable under the headings "RATES" and "POLE INSTALLATION OR REPLACEMENT; REARRANGEMENTS; GUYING" that would have been payable had such attachment been made on the date following the date of the last previous inspection required to be made by Company under applicable regulations of the Kentucky Public Service Commission. N

ABANDONMENT BY OPERATOR.

Operator may at any time abandon the use of a pole hereunder by removing therefrom all of its attachments and by giving written notice thereof, on a form provided by the Company, and no pole shall be considered abandoned until such notice is received.

INDEMNITY.

Operator hereby agrees to indemnify, hold harmless, and defend Company from and against any and all loss, damage, cost or expense which Company may suffer or for which Company may be held liable because of interruption of Operator's service to its subscribers or because of interference with television reception of said subscribers or others, or by reason of bodily injury, including death, to any person, or damage to or destruction of any property, including loss of use thereof, arising out of or in any manner connected with the attachment, operation, and maintenance of the facilities of Operator on the poles of Company under this Tariff, when due to any act, omission or negligence of Operator, or to any such act, omission or negligence of Operator's respective representatives, employees, agents or contractors.

INSURANCE.

Operator agrees to obtain and maintain at all times policies of insurance as follows:

(a) Comprehensive bodily injury liability insurance in an amount not less than $1,000,000 for any one occurrence
(b) Comprehensive property damage liability insurance in an amount not less than $500,000 for any one occurrence.
(c) Contractual liability insurance in an amount not less than the foregoing minimums to cover the liability assumed by the Operator under the agreement or indemnity set forth above.

Prior to making attachments at Company's poles, Operator shall furnish to Company two copies of a certificate, from an insurance carrier licensed to do business in Kentucky, stating that policies of insurance have been issued by it to Operator providing for the insurance listed above and that such policies are in force. Such certificate shall state that the insurance carrier will give Company thirty (30) days' prior written notice of any cancellation of or material change in such policies. T

(Cont'd on Sheet 16-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

EASEMENTS.

Operator shall secure any right, license or permit from any governmental body, authority or other person or persons which may be required for the construction or maintenance of attachments of Operator. Company does not convey nor guarantee any easements, rights-of-way or franchises for the construction and maintenance of said attachments. Operator hereby agrees to indemnify and save harmless Company from any and all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Operator to secure such right, license, permit or easement for the construction or maintenance of said attachments on Company's poles.

CHARGES AND FEES.

Operator agrees to pay Company an annual charge per attachments set forth on Tariff Sheet No. 16-1 in advance, and such other charges as may be provided for herein, for the use of each of Company's poles, any portion of which is occupied by, or reserved at Operator's request for the attachments of Operator. N

Operator agrees to reimburse Company for all reasonable non-recurring expenses caused by or attributable to Operator's initial attachments including without limitation the amounts set forth herein before and the expenses of Company in examining poles used but not owned by Company to which Operator proposes to make attachments.

FEES FOR ADDITIONAL ATTACHMENTS OR REMOVALS.

For attachments made or removed which are reported to the Company between billing dates, Operator shall be billed or credited a prorated amount of the annual charge effective with the date of attachment or removal on the Operator's next bill.

ADVANCE BILLING

Payment of amounts due hereunder is due on the dates or at the times indicated with respect to each such payment. In the event the time for any payment is not specified, such payment shall be due thirty (30) days from the date of the invoice therefore. In all amounts not so paid an addition charge of five percent (5%) will be assessed. Where the provisions of the Tariff require any payment by Operator to the Company other than for attachment charges, Company may, at its option, require that the estimated amount thereof be paid in advance of permission to use any pole or the performance by company of any work. In such a case, Company shall invoice any deficiency or refund any excess to Operator after the current amount of such payment has been determined. T

DEFAULT OR NON-COMPLIANCE.

If Operator fails to comply with any of the provisions of this Tariff or defaults in the performance of any of its obligations under this Tariff and fails within thirty (30) days, after written notice from Company to correct such default or non-compliance, Company may, in addition to all other remedies under this tariff forthwith take any one or more of the following actions: terminate the specific permit or permits covering the poles to which such default or non-compliance is applicable; remove, relocate or rearrange attachments of Operator to which such default or non-compliance relates, all at Operator's expense; decline to permit additional attachments hereunder until such default is cured; or in the event of any failure to pay any of the charges, fees or amounts provided in this Tariff or any other substantial default, or of repeated defaults terminate Operator's right of attachment. No liability shall be incurred by Company because of any or all such actions except for negligent destruction by the Company of CATV equipment in any relocation or removal of such equipment. The remedies provided herein are cumulative and in addition to any other remedies available to Company. N

(Cont'd on Sheet No. 16-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C. A. T. V. (Cont'd)
(Cable Television Pole Attachment)

PRIOR AGREEMENTS.

This Tariff terminates and supersedes any previous agreement, license or joint use affecting Company's poles and Operator's attachments covered herein.

ASSIGNMENT.

This Tariff shall be binding upon and inure to the benefits of the parties hereto, their respective successors and/or assigns, but Operator shall not assign, transfer or sublet any of the rights hereby granted without the prior written consent of the Company, which shall not be unreasonably withheld, and any such purported assignment, transfer or subletting without such consent shall be void.

PERFORMANCE WAIVER.

Neither party shall be considered in default in the performance of its obligations herein, or any of them, to the extent that performance is delayed or prevented due to causes beyond the control of said party, including but not limited to, Acts of God or the public enemy, war, revolution, civil commotion, blockade or embargo, acts of government, any law, order, proclamation, regulation, ordinance, demand, or requirement of any government, fires, explosions, cyclones, floods, unavoidable casualties, quarantine, restrictions, strikes, labor disputes, lock-outs, and other causes beyond the reasonable control of either of the parties.

PRESERVATION OF REMEDIES.

No delay or omission in the exercise of any power or remedy herein provided or otherwise available to the Company shall impair or affect its right thereafter to exercise the same.

TARIFF COGEN/SPP I
(Cogeneration and/or Small Power Production--100 KW or Less)

AVAILABILITY OF SERVICE.

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a total design capacity of 100 KW or less. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1- The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

MONTHLY CHARGES FOR DELIVERY FROM THE COMPANY TO THE CUSTOMER.

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Not Applicable. N

(Cont'd on Sheet No. 17-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP I (Cont'd.)
(Cogeneration and/or Small Power Production--100 KW or Less)

ADDITIONAL CHARGES. (Cont'd.)

Monthly Metering Charge (Cont'd.)

Options 2 & 3 - Where meters are used to measure the excess or total energy and average on-peak capacity purchased by the Company:

	Single Phase	Polyphase	
Standard Measurement	$ 8.50	$ 11.10	I I
T.O.D. Measurement	$ 9.05	$ 11.40	I I

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each use.

Local Facilities Charge

Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH .... 3.79¢ KWH I
T.O.D. Meter
On-Peak KWH .... 4.64¢ KWH I
Off-Peak KWH .... 3.18¢ KWH I

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

(Cont'd on Sheet No. 17-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP I (Cont'd.)
(Cogeneration and/or Small Power Production--100 KW or Less)

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES. (Cont'd.)

Capacity Credit (Cont'd.)

If standard energy meters are used,

A. $ 3.70 KW/month, times the lowest of: I

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used,

B. $8.87 KW/month, times the lowest of: I

(1) on-peak contract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305 or T

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

ON-PEAK AND OFF-PEAK PERIODS.

The on-peak period shall be defined as starting at 7:00A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00A.M. local time, Monday through Friday, and all hours of Saturday and Sunday.

CHARGES FOR CANCELLATION OR NON PERFORMANCE CONTRACT.

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP I or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

TERM OF CONTRACT.

Contracts under this tariff shall be made for a period not less than one year.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP II
(Cogeneration and/or Small Power Production--Over 100 KW)

AVAILABILITY OF SERVICE.

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a total design capacity of over 100 KW but less than 20,000 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

MONTHLY CHARGES FOR DELIVERY FROM THE COMPANY TO THE CUSTOMER.

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Not Applicable. N

(Cont'd on Sheet No. 18-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP II (Cont'd.)
(Cogeneration and/or Small Power Production--Over 100 KW)

ADDITIONAL CHARGES. (Cont'd.)

Monthly Metering Charge (Cont'd)

Options 2 & 3- Where meters are used to measure the excess or total energy and average on peak capacity purchased by the Company:

	Single Phase	Polyphase	
Standard Measurement	$ 8.50	$ 11.10	I I
T.O.D. Measurement	$ 9.05	$ 11.40	I I

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

Local Facilities Charge

Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH .... 3.79¢ KWH I

T.O.D. Meter
On-Peak KWH .... 4.64¢ KWH I
Off-Peak KWH .... 3.18¢ KWH I

(Cont'd on Sheet No. 18-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP II (Cont'd.)
(Cogeneration and/or Small Power Production--Over 100 KW)

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES. (Cont'd.)

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. $3.70/KW/ month, times the lowest of: I

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730,or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used,

B. $8.87/KW/month, times the lowest of: I

(1) on-peak contract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305, or T

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

ON-PEAK AND OFF-PEAK PERIODS.

The on-peak period shall be defined as starting at 7:00 A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00 A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

CHARGES FOR CANCELLATION OR NON PERFORMANCE CONTRACT.

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP II or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

TERM OF CONTRACT.

Contracts under this tariff shall be made for a period not less than one year.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S. S. C.
(System Sales Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ,*I.G.S.,* C.S.- I.R.P., M.W., O.L. and S.L. T T

RATE.

1. When the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as provided in paragraph 2 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   System Sales Adjustment Factor (A) = (.6 [Tm - Tb])/Sm

   In the above formulas "T" is Kentucky Power Company's (KPCo) monthly net revenues from system sales in the current (m) and base (b) periods, and "S" is the KWH sales in the current (m) period, all defined below.

2. The net revenue from KPCo's sales to non-associated companies as reported in the FERC Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows: N

   a. KPCo's total revenues from system sales as recorded in Account 447, less b. and c. below.

   b. KPCo's total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

   c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report. N

(Cont'd on Sheet No. 19-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S. S. C. (Cont'd.)
(System Sales Clause)

3. The base monthly net revenues from system sales are as follows:

Billing Month	System Sales (Total Company Basis)	
January	$ 1,560,360	I
February	1,335,811	I
March	1,296,845	R
April	1,152,503	R
May	1,170,480	R
June	1,106,499	I
July	1,322,384	I
August	1,031,319	R
September	1,038,816	R
October	1,088,125	R
November	1,123,099	R
December	1,073,722	R
	$14,299,964	R

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon estimated monthly revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

6. The monthly System Sales Clause shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF F.T.
(Franchise Tariff)

AVAILABILITY OF SERVICE.

Where a city or town within Kentucky Power's service territory requires the Company to pay a percentage of revenues from certain customer classifications collected within such city or town of the right to erect the Company's poles, conductors, or other apparatus along, over, under, or across such city's or town's streets, alleys, or public grounds, the Company shall increase the rates and charges to such customer classifications within such city or town by a like percentage. The aforesaid charge shall be separately stated and identified on each affected customer's bill.

TARIFF T. S.
(Temporary Service)

AVAILABILITY OF SERVICE.

Where capacity is available, Company will install service for temporary lighting and power service. Residential customers will be supplied with 100 amp service. All other customer classes will be supplied at voltage levels applicable to the class of business. N

RATE. (Tariff Code 019) T

Temporary service will be supplied under any published tariff applicable to the class of business of the Customer, when the Company has available unsold capacity of lines, transforming and generating equipment, with an additional charge of the total cost of connection and disconnection.

MINIMUM CHARGE.

The same minimum charge as provided for in any applicable tariff shall be applicable to such temporary service and for not less than one full monthly minimum.

TERM.

Variable. Initial period of 180 days. The Company may extend for an additional 90 day period. N

SPECIAL TERMS AND CONDITIONS.

A deposit equal to the full estimated amount of the bill and/or construction costs under this tariff may be required.

This tariff is not available to customers permanently located, whose energy requirements are of a seasonal nature.

See Terms and Conditions of Service.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(Demand-Side Management Adjustment Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ,*I.G.S.*, C.S.-I.R.P., and M.W. T

RATE.

1. The Demand-Side Management (DSM) clause shall provide for periodic adjustment per KWH of sales equal to the DSM costs per KWH by customer sector according to the following formula:

$$\text{Adjustment Factor} = \frac{DSM(c)}{S(c)}$$

Where DSM is the cost by customer sector of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances; (c) is customer sector; and S is the adjusted KWH sales by customer sector.

2. Demand-Side Management (DSM) costs shall be the most recent forecasted cost plus any over/under recovery balances recorded at the end of the previous period.

   a. Program costs are any costs the Company incurred associated with demand-side management which were approved by the Kentucky Power Company DSM Collaborative. Examples of costs to be included are contract services, allowances, promotion, expenses, evaluation, lease expense, etc. by customer sector.

   b. Net lost revenues are the calculated net lost revenues by customer sector resulting from the implementation of the DSM programs.

   c. Incentives are a shared-savings incentive plan consisting of one of the following elements: The efficiency incentive, which is defined as 15 percent of the estimated net savings associated with the programs. Estimated net savings are calculated based on the California Standard Practice Manual's definition of the Total Resources Cost (TRC) test, or the maximizing incentive which is defined as 5 percent of actual program expenditures if program savings cannot be measured.

   d. Over/ Under recovery balances are the total of the differences between the following:

      (i) the actual program costs incurred versus the program costs recovered through DSM adjustment clause, and

      (ii) the calculated net lost revenues realized versus the net lost revenues recovered through the DSM adjustment clause, and

      (iii) the calculated incentive to be recovered versus the incentive recovered through the DSM adjustment clause.

3. Sales (S) shall be the total ultimate KWH sales by customer sector less non-metered, opt-out and lost revenue impact KWHs by customer sector.

4. The provisions of the Demand-Side Management Adjustment Clause will be effective for the period ending December 31, 2011.

(Cont'd on Sheet No. 22-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

RATE. (Cont'd.)

5. The DSM adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

7. The resulting range for each customer sector per KWH during the three-year Experimental Demand-Side Management Plan is as follows:

		CUSTOMER SECTOR		
		RESIDENTIAL ($ Per KWH)	COMMERCIAL ($ Per KWH)	INDUSTRIAL*
Floor Factor	=	0.000614	0.000326	- 0 -
Ceiling Factor	=	0.002279	0.001645	- 0 -

8. The DSM Adjustment Clause factor ($ Per KWH) for each customer sector which fall within the range defined in Item 7 above is as follows:

	CUSTOMER SECTOR		
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL*
DSM (c)	1,681,109	651,981	- 0 -
S (c)	1,161,789,200	661,238,700	- 0 –
Adjustment Factor	$ 0.001447	$ 0.000986	- 0 –

* The Industrial Sector has been discontinued pursuant to the Commission's Order dated September 28, 1999.

PROGRAM DESCRIPTIONS.

The D.S.M.C. program availability, program, rate, and equipment descriptions follow:

(Cont'd on Sheet 22-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: TEE – Targeted Energy Efficiency

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers receiving retail electric service from the Company, who have primary electric heat and use an average of 700 kWh per month. Residential customers without primary electric heating may also be eligible for limited efficiency measures if they have electric water heating and use an average of 700 kWh from November through March. To qualify, the household's income cannot exceed the designated poverty guidelines as administered by your community action agency. The household must also qualify according to the guidelines for the Weatherization Assistance Programs administered by the communication community action agencies.

PROGRAM DESCRIPTION

The Kentucky Power Targeted Energy Efficiency Program (TEE) provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies. The program funding and service is supplemental to the Weatherization Assistance Programs offered by your community action agency. This program provides energy saving improvements to your existing home. Program services can include these items, as applicable and per program guidelines:

- Energy audit
- Air infiltration diagnostic test to find air leaks
- Air leakage sealing
- Attic, floor, side-wall insulation
- Duct sealing and insulation
- High efficiency compact fluorescent light bulbs (CFLs)
- Domestic hot water heating insulation (electric)
- Customer education on home energy efficiency
- Partial funding High efficiency heat pump (restrictions apply)

RATE

No rate applies for this program.

EQUIPMENT

The Kentucky Community Action network of not-for-profit community action agencies will furnish and install, in the customer's presence, the equipment as provided by this program.

(Cont'd on Sheet No. 22-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: MEF – Modified Energy Fitness

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers living in a single-family residence, who receive retail all-electric service from the Company and use an average of 1,000 kWh per month over the last twelve months. Customers living in site built homes and mobile homes are eligible.

PROGRAM DESCRIPTION

The Kentucky Power Modified Energy Fitness Program (MEF) provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. This program provides energy saving improvements to a customer's existing home. Program services may include these items, as applicable and per program guidelines:

- Complete energy audit with customized report
- Air infiltration diagnostic test to find air leaks
- Energy savings booklet
- Energy conservation measures installed (per program guidelines)

RATE

No rate applies for this program.

EQUIPMENT

The Company, or its authorized agents, will furnish and install, in the customer's presence, the energy conservation measures as provided by this program.

(Cont'd on Sheet No. 22-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: EEFS – Energy Education for Students

AVAILABILITY OF SERVICE

All schools within Kentucky Power's service territory are eligible to participate. The program targets 7th grade students.

PROGRAM DESCRIPTION

The Kentucky Power Student Energy Education Program (EEFS) targets 7th grade students at participating schools within the Kentucky Power Company service territory. The program introduces them to various aspects of responsible energy use and conservation. With this program, students use math and science skills to learn how energy is produced and used, and methods to conserve energy that can easily be applied in their own homes.

The Company partners with the National Energy Education Development Project (NEED) to implement this program. NEED is an established and respected energy education organization that has been presenting programs for teachers and students in Eastern Kentucky for many years. The program, provided at no cost to participating school systems, includes:

- Professional development for teachers where they will receive classroom curriculum and educational materials on energy, electricity, economics and the environment
- Each Student receives compact fluorescent lights (CFLs) to help students apply their classroom learning at home
- An opportunity for participating students and their families to make the ENERGY STAR® Pledge

RATE

No rate applies for this program.

EQUIPMENT

The CFLs furnished by the Company are delivered to the schools for delivery to students. The CFLs will not be installed by the Company, or its authorized agents.

(Cont'd on Sheet No. 22-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: COCFL – Community Outreach CFL

AVAILABILITY OF SERVICE

All residential retail customers of Kentucky Power are eligible for the program.

PROGRAM DESCRIPTION

Through the CFL Outreach Program, Kentucky Power distributes compact fluorescent lights (CFLs) to customers at company-sponsored community events. The program aims to educate and encourage customers to save money by using energy efficient lighting. The company sponsors community distribution events throughout the year where a package of CFLs is distributed to each qualifying residential customer. Customer energy education is also provided at these events.

RATE

No rate applies for this program.

EQUIPMENT

The CFLs furnished by the Company are delivered to the community events and provided to customers having an active electric account. The CFLs will not be installed by the Company, or its authorized agents.

(Cont'd on Sheet No. 22-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 22-7
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 22-7

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: REP - Residential Efficient Products

AVAILABILITY OF SERVICE

All Kentucky Power residential customers are eligible to participate.

PROGRAM DESCRIPTION

The Kentucky Power Residential Efficient Products Program (REP) offers residential customers instant rebates on ENERGY STAR lighting products at participating retail stores across our service territory. The program targets the purchase of lighting products through in-store promotion as well as special sales events. Customer incentives facilitate the increased purchase of high efficiency products while in-store signage, sales associate training and support makes provider participation easier.

A convenient online store where customers can shop for energy efficient lighting and get immediate discounts is also available, including specialty and hard-to-find CFLs. LED holiday lights, LED nightlights, and ENERGY STAR® ceiling fans.

RATE

Vendor controlled and adjusted in-store rebates can range from $1.00 per single pack up to $3.00 per multi pack, for up to a12-bulb limit per purchase are available while funds last.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase and install the required equipment.

(Cont'd on Sheet No. 22-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: HEHP – High Efficiency Heat Pump

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers who live in site built homes with a central electric resistance heating system or an existing less efficient heat pump system and have received retail electric service from the Company for the past twelve months at that residence.

PROGRAM DESCRIPTION

The Kentucky Power High Efficiency Heat Pump (HEHP) offers an incentive to residential customers who upgrade their central electric resistance heating system or existing less efficient heat pump system to a new, high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance Factor) for resistance heat upgrade, or 14 SEER and 8.2 HSPF for upgrading from a less efficient existing heat pump to a high efficiency heat pump unit.

RATE

A $400 incentive is offered to residential customers that qualify.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase and install the required equipment by an approved HVAC dealer participating in the program.

(Cont'd on Sheet No. 22-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: MHHP – Mobile Home High Efficiency Heat Pump

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers who live in a mobile home with a central electric resistance heating system and have received retail electric service from the Company for the past twelve months at that residence.

PROGRAM DESCRIPTION

The Kentucky Power Mobile Home High Efficiency Heat Pump (MHHP) offers an incentive to residential customers who live in a mobile home and upgrade their central electric resistance heating system with a new, high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance Factor).

RATE

A $400 incentive is offered to residential customers that qualify.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase and install the required equipment by an approved HVAC dealer participating in the program.

(Cont'd on Sheet No. 22-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: MHNC – Mobile Home New Construction

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers who purchase a new mobile home built with Zone 3 insulation and a high efficiency heat pump.

PROGRAM DESCRIPTION

The Kentucky Power Mobile Home New Construction (MHNC) offers an incentive to residential customers who purchase a new mobile home having an insulation upgrade and a high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance Factor).

RATE

A $500 incentive is offered to residential customers that qualify.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase the new mobile home from a manufactured housing dealer participating in the program and who can administer an upgrade for required equipment.

(Cont'd on Sheet No. 22-11)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 22-11
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 22-11

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: Residential & Commercial HVAC Diagnostic and Tune-up

AVAILABILITY OF SERVICE

Available to Kentucky Power residential customers and small commercial customers using less than 100 kW peak demand having unitary central heat pump systems. The Kentucky Power Small Commercial HVAC Program encourages small commercial customers to keep their heating, ventilation and air conditioning (HVAC) equipment operating at peak efficiency, by way of a simple tune-up.. The program is not applicable for customers seeking repair of non-operational units.

PROGRAM DESCRIPTION – HVAC Diagnostic and Tune-up Program

The residential and commercial customer will be offered an incentive when receiving this Diagnostic and Tune-up service from a participating, state licensed contractor. It will help extend the life of the system, reduce energy costs and improve the interior comfort of your business. The diagnostic and tune-up service includes testing for inefficiencies in air conditioning and heat pump systems due to air-restricted indoor or outdoor coils and over or under refrigerant charge.

RATE

A $50 incentive is offered to residential customers and commercial customers that qualify.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to contact a participating state licensed program dealer who can administer the diagnostic service.

(Cont'd on Sheet No. 22-12)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: Small Commercial HVAC Programs

AVAILABILITY OF SERVICE

Available to Kentucky Power commercial customers using less than 100 kW peak demand whose primary heat source is electricity. The Kentucky Power Small Commercial HVAC Program encourages small commercial customers to keep their heating, ventilation, and air conditioning (HVAC) equipment operating at peak efficiency by an equipment upgrade.

PROGRAM DESCRIPTION – High Efficiency Heat Pump/Air Conditioner Program

The commercial customer will receive financial incentives for upgrading to a new qualifying central air conditioning or heat pump system (up to a five-ton unit with a Consortium for Energy Efficiency (CEE) Tier 1 rating). The incentive helps offset the cost of the investment, and the improved efficiency can give long-term savings.

RATE

The following incentives are offered for qualifying purchases:

Air Conditioner - 36,000 Btu/h or lower	Incentive = $250
Air Conditioner - 36,000 – 65,000 Btu/h	Incentive = $400
Heat Pump - 36,000 Btu/h or lower	Incentive = $300
Heat Pump - 36,000 – 65,000 Btu/h	Incentive = $450

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase the high efficiency heat pump or air conditioner from a participating program dealer who can administer an upgrade for required equipment.

(Cont'd on Sheet No. 22-13)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 22-13
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 22-13

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: CIP – Commercial Incentive Program

AVAILABILITY OF SERVICE

All commercial (non-industrial) customers in Kentucky Power's service territory are eligible to participate.

PROGRAM DESCRIPTION

The Kentucky Power Commercial Incentive Program (CIP) offers a convenient way to receive funding for common energy efficiency projects. The Commercial Incentive Program provides financial incentives to business customers who implement qualified energy-efficient improvements and technologies.

Incentives are available for a variety of energy-saving technologies in existing buildings and new construction projects. Choose from a menu of prescriptive measures with standardized incentives. The program menu includes, but is not limited to, incentives for:

- Lighting
- Heating, ventilation, and air conditioning (HVAC)
- Food Service and Refrigeration

A complete list of the eligible equipment and incentive amounts can be found in the Program Application located at KentuckyPower.com/save/programs.

RATE

The maximum payout is 50% of incremental equipment costs, up to $20,000 annually per customer account is offered to qualifying commercial customers that qualify.

The Company, or its authorized agents, will administer the evaluation of customer installed energy measures. The Company, or its authorized agents, may provide support for the installation services through approved program contractors.

AGREEMENT

A customer program application agreement is required to participate in this program.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF B.E.R.
(Biomass Energy Rider)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S.,L.G.S.O.D., *I.G.S.,* C.S.-I.R.P., M.W., O.L. and S.L. T

RATE.

1. When energy is generated and sold to the Company from the ecopower biomass facility, an additional charge equal to the product of the kWh of sales and a biomass adjustment factor (A) shall be made, where, "A", calculated to the nearest 0.0001 mil per kilowatt=hour, is defined as set forth below.

   Biomass Adjustment Factor (A)=(R*Pm)/Sm

   In the above formulas "R" is the rate for the current calendar year approved by this commission in the REPA between ecopower and Kentucky Power Company, "P" is the about of Kwh purchased by Kentucky Power in the current (m) period, and "S" is the kWh sales in the current (m) period, all defined below.

2. Rate (R) shall be the dollar per MWh as defined in the REPA between ecopower and Kentucky Power Company, including any applicable escalation factor as defined in the REPA.

3. Produced energy (P) shall be the MWh produced and sold to Kentucky Power Company.

4. Sales (S) shall be all KWh sold, excluding intersystem sales. Utility used energy shall not be excluded in the determination of sales (S).

5. Any over/under recovery will be reflected in the monthly filing for the second billing moth following the month the cost is incurred.

6. The monthly bio mass energy rider shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 24-1**
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 24-1

TARIFF P.J.M.R.
(PJM RIDER)

N

APPLICABLE:

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES: (Tariff Code 390)

Tariff Class	¢/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	0.0000	--
S.G.S. and S.G.S.-T.O.D.	0.0000	--
M.G.S.	0.0000	0.00
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	0.0000	--
L.G.S. and L.G.S.-T.O.D.	0.0000	0.00
L.G.S.-L.M.-T.O.D.	0.0000	0.00
I.G.S. and C.S.-I.R.P	0.0000	0.00
M.W.	0.0000	--
O.L.	0.0000	--
S.L.	0.0000	--

The kWh adjustment factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW adjustment factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS and IGS tariff classes.

The PJM Rider adjustment factor shall be modified annually to reflect the difference between the approved base level of PJM charges and credits and the PJM charges and credits actually experienced.

The PJM Rider adjustment factor shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Adjustment Factor} = \frac{PJME \times (BE_{Class} / BE_{Total}) + PJMD \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Adjustment Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Adjustment Factor} = \frac{PJME \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Adjustment Factor} = \frac{PJMD \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

N

(Cont'd on Sheet 24-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission
In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 24-2
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 24-2

PJM RIDER (Cont'd)
(P.J.M.R.)

N

RATES: (Cont'd)

Where:

1. "PJMD" is the actual (over)/under recovery of annual retail PJM demand-related net costs; calculated by comparing the amount of PJM demand-related net costs in base rates to those retail PJM demand-related net costs actually incurred during the review period.

2. "PJME" is the actual (over)/under recovery of annual retail PJM energy-related net costs; calculated by comparing the amount of PJM energy-related net costs in base rates to those retail PJM energy-related net costs actually incurred during the review period.

3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.

4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
(1)	(2)	(3)	(4)=(2)x(3)
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2		0.0236060%	
S.G.S. and S.G.S.-T.O.D.		0.0163937%	
M.G.S.		0.0177002%	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		0.0177002%	
L.G.S.and L.G.S.-T.O.D.		0.0169381%	
L.G.S.-L.M.-T.O.D.		0.0169381%	
I.G.S.and C.S.-I.R.P		0.0130626%	
M.W.		0.0134057%	
O.L.		0.0009431%	
S.L.		0.0009890%	
	BE_{Total}		CP_{Total}

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.

7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.

The adjustment factor as computed above shall be further modified to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the PJM Rider adjustment revenues.

N

(Cont'd on Sheet 24-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

P.J.M. RIDER (Cont'd)
P.J.M.R.

N

The annual PJM Rider shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 25- 1
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 25- 1

RESERVED FOR FUTURE USE T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 25-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 25-2

RESERVED FOR FUTURE USE T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 25-3
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 25-3

RESERVED FOR FUTURE USE T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.U.G.
(Non-Utility Generator)

AVAILABILITY OF SERVICE.

This tariff is applicable to customers with generation facilities which have a total design capacity of over 1,000 kW that intends to schedule, deliver and sell the net electric output of the facility at wholesale, and who require Commissioning Power, Startup Power and/or Station Power service from the Company.

Service to any load that is electrically isolated from the Customer's generator shall be separately metered and provided in accordance with the generally available demand-metered tariff appropriate for such service to the Customer.

This tariff is not available for standby, backup, maintenance, or supplemental service for wholesale or retail loads served by customer's generator.

DEFINITIONS.

1. **Commissioning Power** - The electrical energy and capacity supplied to the customer prior to the commercial operation of the customer's generator, including initial construction and testing phases.
2. **Station Power** - The electrical energy and capacity supplied to the customer to serve the auxiliary loads at the customer's generation facilities, usually when the customer's generator is not operating. Station Power does not include Startup Power.
3. **Startup Power** - The electrical energy and capacity supplied to the customer following a planned or forced outage of the customer's generator for the purpose of returning the customer's generator to synchronous operation.

COMMISSIONING POWER SERVICE.

Customers requiring Commissioning Power shall take service under Tariff T.S. or by special agreement with the Company.

The Customer shall coordinate its construction and testing with the Company to ensure that the customer's operations do not cause any undue interference with the Company's obligations to provide service to its other customers or impose a burden on the Company's system or any system interconnected with the Company.

STATION POWER SERVICE.

Customers requiring Station Power shall take service under the generally available demand-metered tariff appropriate for the customer's Station Power requirements.

Station Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Station Power requirements that the Company is expected to supply under the generally available demand-metered tariff appropriate for the customer.

STARTUP POWER SERVICE.

Customers requiring Startup Power have the option of contracting for such service under the terms of this tariff or under the generally available demand-metered tariff appropriate for the customer's Startup Power requirements.

Startup Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Startup Power requirements that the Company is expected to supply.

Startup Duration – The Customer shall contract for a definite number of hours sufficient to meet the maximum period of time for which the Company is expected to supply Startup Power.

(Cont'd on Sheet No. 26-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 26-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 26-2

TARIFF N.U.G. (Cont'd)
(Non-Utility Generator)

STARTUP POWER SERVICE. (cont'd)

Startup Duration – The Customer shall contract for a definite number of hours sufficient to meet the maximum period of time for which the Company is expected to supply Startup Power.

Startup Frequency – The Customer shall contract for a definite number of startup events sufficient to meet the maximum number of times per year that the Company is expected to supply Startup Power.

Other Startup Characteristics – The customer shall provide to the Company other information regarding the customer's Startup Power requirements, including, but not limited to, anticipated time-of-use and seasonal characteristics.

Notification Requirement - Whenever Startup Power is needed, the Customer shall provide advance notice to the Company.

Upon receipt of a request from the Customer for Startup Power Service under the terms of this tariff, the Company will provide the Customer a written offer containing the Notification Requirement, generation, transmission and distribution rates (including demand and energy charges) and related terms and conditions of service under which service will be provided by the Company. Such offer shall be based upon the Startup Contract Capacity, Startup Duration, Startup Frequency, and Other Startup Characteristics as specified by the customer. In no event shall the rates be less than the sum of the Tariff I.G.S. Energy Charge, the Fuel Adjustment Clause, the System Sales clause, the Demand-Side Management Adjustment Clause, Asset Transfer Rider, Big Sandy Retirement Rider, Big Sandy 1 Operation Rider, Purchase Power Rider, P.J.M. Rider, KY Economic Development Surcharge, Environmental Surcharge, the Capacity Charge and NERC Compliance and Cybersecurity Rider. T T T T T

If the parties reach an agreement based upon the offer provided to the customer by the Company, a contract shall be executed that provides full disclosure of all rates, terms and conditions of service under this tariff, and any and all agreements related thereto.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

(Cont'd on Sheet No. 26-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.U.G. (Cont'd)
(Non-Utility Generator)

MONTHLY BILLING DEMAND.

The monthly billing demand in kW shall be taken each month as the highest single 15-minute integrated peak in kW as registered by a demand meter or indicator, less the Station Contract Capacity. The monthly billing demand so established shall in no event be less than the greater of (a) the Startup Contract Capacity or b) the customer's highest previously established monthly billing demand during the past 11 months.

MONTHLY BILLING ENERGY.

Interval billing energy shall be measured each 15-minute interval of the month as the total KWH registered by an energy meter or meters less the quotient of the Station Contract Capacity and four (4). In no event shall the interval billing energy be less than zero (0). Monthly billing energy shall be the sum of the interval billing energy for all intervals of the billing month.

TRANSMISSION SERVICE.

Transmission Provider – The entity providing transmission service to customers in the Company's service territory. Such entity may be the Company or a regional transmission entity.

Prior to taking service under this tariff, the Customer must have a fully executed Interconnection and Operation Agreement with the Company and/or the Transmission Provider or an unexecuted agreement filed with the Federal Energy Regulatory Commission under applicable procedures.

Should the Transmission Provider implement charges for Transmission Congestion, the Company shall provide 30 days written notice to the customer. Upon the expiration of such notice period, should the customer's use of Startup Power result in any charges for Transmission Congestion from the Transmission Provider, such charges, including any applicable taxes or assessments, shall be paid by or passed through to the customer without markup. Transmission Congestion is the condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system.

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than one year.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 kW.

SPECIAL TERMS AND CONDITIONS.

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

This tariff shall not obligate the Company to purchase or pay for any capacity or energy produced by the Customer's generator.

Customers desiring to provide Startup and Station Power from commonly owned generation facilities that are not located on the site of the customer's generator (remote self-supply), shall take service under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

AVAILIBILITY OF SERVICE.

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer-generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than thirty (30) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

METERING.

Net energy metering shall be accomplished using a standard kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

BILLING/MONTHLY CHARGES.

Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non-energy charge portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the customer shall be credited in the next billing period for the kWh difference. If time-of-day metering is used, energy flows in both directions shall be netted and accounted for at the specific time-of-use in accordance with the provisions of the customer's standard tariff and this Net Metering Service Tariff. When the customer elects to no longer take service under this Net Metering Service Tariff, any unused credit shall revert to the Company. Excess electricity credits are not transferable between customers or locations.

(Cont'd on Sheet No. 27-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

APPLICATION AND APPROVAL PROCESS.

The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

LEVEL 1 AND LEVEL 2 DEFINITIONS.

LEVEL 1
A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.

(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.

(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.

(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.

(6) The interconnection will not be on an area or spot network.

(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."

(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

(Cont'd on Sheet No. 27-3)

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

LEVEL 1, continued

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

LEVEL 2

A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

(Cont'd on Sheet No. 27-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

LEVEL 2, continued

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

APPLICATION, INSPECTION AND PROCESSING FEES.

No application fee or other review, study, or inspection or witness test fees will be charged by the company for Level I application.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $50. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

(Cont'd on Sheet No. 27-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION.

To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(Cont'd on Sheet No. 27-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION, continued

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(Cont'd on Sheet No. 27-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION, continued

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERM OF CONTRACT.

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

(Cont'd on Sheet No. 27-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 30 kW generation capacity and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com) T

T

Applicant

Name: ____________________

Mailing Address: ____________________

City: ____________ State: ________ Zip: ________

Phone: (____) ____________ Phone: (____) ____________

E-mail address: ____________________

Service Location

Street Address: ____________________

City: ____________ State: ________ Zip: ________

Electric Service Account Number: ____________________

Alternate Contacts

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Name	Company	Telephone/Email

(Cont'd on Sheet No. 27-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: ________________________ Model: ____________________________________

Inverter Power Rating: ________________________ Voltage Rating: ____________________________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ____________________________

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating: ____________________________

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ________________________

(Cont'd on Sheet No. 27-11)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1:

1 Kentucky Power Company (Company) shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(Cont'd on Sheet No. 27-12)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

(Cont'd on Sheet No. 27-13)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-14)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: ____________________________ **Date:** ______________

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.

Call: _______________ to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

____

Approved by: ____________________________ **Date:** ______________

Printed Name: ____________________________ **Title:** ______________

(Cont'd on Sheet No. 27-15)

TARIFF N.M.S.
(Net Metering Service)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 30kW generation).

Submit this Application (along with the application fee of $100) to:

DG Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com T

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com) T

Applicant

Name: ______________________________

Mailing Address: ______________________________

City: ____________________ State: __________ Zip: __________

Project Contact Person: ______________________________

Phone: (____) ____________________ Phone: (____) ____________________

E-mail Address: ______________________________

Service Location

Street Address: ______________________________

City: ____________________ State: __________ Zip: __________

Electric Service Account Number: ______________________________

Alternate Contacts

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Name	Company	Telephone/Email

(Cont'd on Sheet No. 27-16)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

APPPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility: ______________________________

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ________________________

(Cont'd on Sheet No. 27-17)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this _____ day of ___________, 20___, by and between Kentucky Power Company (Company), and ________________________________ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: ____

Generator Size and Type: ____

Now, Therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

(Cont'd on Sheet No. 27-18)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1 Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(Cont'd on Sheet No. 27-19)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6 Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(Cont'd on Sheet No. 27-20)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity is allowed without approval.

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-21)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature: ______________________ **Date:** ______________

Printed Name: ______________________ **Title:** ______________

Company Signature: ______________________ **Date:** ______________

Printed Name: ______________________ **Title:** ______________

(Cont'd on Sheet No. 27-22)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.
- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.
- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 28-1
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 28-1

TARIFF C.C.
(Capacity Charge)

AVAILABILITY OF SERVICE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S.,L.G.S.-T.O.D., I.G.S. C.S.-I.R.P., M.W., O.L. and S.L. T T

RATE.

	Service Tariff		
	All Other	I.G.S.	T
Energy Charge per KWH per month	$ 0.001182	$ 0.000659	I R

RATE CALCULATION.

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2004-00420 and the Settlement and Stipulation Agreement dated October 20, 2004 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the supplemental annual payments tied to the 18-year extension of the Rockport Unit Power Service Agreement (UPSA). Kentucky Power will apply surcharges designed to enable recovery from each tariff class of customers, an annual supplemental payment of $5.1 million annually in Years 2005 through 2009, and then increases to $6.2 million annually in Years 2010 through 2021, and then decreases to $5,792,329 in Year 2022.

2. Kentucky Power will be entitled to receive these annual supplemental payments in addition to the base retail rates established by the Commission. The costs associated with the underlying Rockport Unit 1 and 2 UPSA will continue to be included in base rates.

3. The increased annual revenues will be generated by two different KWH rates, one for I.G.S. tariff customers and one for All Other tariff customers. T

4. The allocation of the additional revenues to be collected from the I.G.S. tariff customers and All Other tariff customers will be based upon the total annual revenue of each of the two-customer classes. Once the additional revenues have been allocated between the two customer classes based upon total annual Kentucky retail revenue, the additional revenue will be collected within the two customer classes (I.G.S. and All Other tariffs) on a KWH basis. The KWH rate to be applied to each of these two customer class groups shall be sufficient to generate that portion of the total increase in annual revenues equal to the percentage of total annual revenues produced by each of the two customer class groups (I.G.S. and All Other tariffs). T T T

5. The Stipulation and Settlement Agreement is made upon the express agreement by the Parties that the receipt by Kentucky Power of the additional revenues called for by Section III(1)(a) and III(1)(b) shall be accorded the ratemaking treatment set out in Section III. In any proceeding affecting the rates of Kentucky Power during the extension of the UPSA under this Stipulation and Settlement Agreement, the provisions of Section III are an express exception to Section VI(4) of the Stipulation and Settlement Agreement.

6. The Capacity Charge factors will be applied to bills monthly and will be shown on the Customer's bill as a separate line item.

(Cont'd on Sheet No. 28-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.C.
(Capacity Charge) Cont'd

RATE CALCULATION. (Cont'd) N

7. The capacity charge will be adjusted annually to recover amounts authorized by the Commission.

The annual adjustment shall be determined as follows:

A. Calculate the revenue over / under collection for the previous 12 month period, REVbilled – REVsettlement = REVdiff

B. Calculate the revenue requirement for the upcoming 12 month period, REVsettlement + REVdiff = REVauthorized

C. Calculate Capacity Charge Rates for the upcoming 12 month period,

$$\text{IGS Capacity Charge} = \frac{\text{REVauthorized x (REVIGS / REVTotal)}}{\text{kWhIGS}}$$

$$\text{All Other Capacity Charge} = \frac{\text{REVauthorized x (REVAll Other / REVTotal)}}{\text{kWhAll Other}}$$

Where:

"REVTotal" is the total revenue billed during the most recently available 12 month period.

"REVIGS" is the total IGS customer class revenue billed during the most recently available 12 month period.

"REVAll Other" is the revenue billed from all other customer classes during the most recently available 12 month period.

"kWhIGS" is the IGS customer class total kWh billed during the most recently available 12 month period.

"kWhAll Other" is the total kWh billed to all customer classes other than IGS during the most recently available 12 month period.

"REVbilled" is the total capacity charge revenue billed during the most recently available 12 month period.

"REVsettlement" is the $6.2 million amount authorized to be billed during the 12 month period.

"REVdiff" is the difference between capacity charge revenues billed and what the Company is authorized to collect in a 12 month period.

"REVauthorized" is the capacity charge amount to be billed over the upcoming 12 month period.

8. The annual Capacity Charge Adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-1
CANCELLING P.S.C. KY. NO. 10 __________ SHEET NO. 29-1

TARIFF E.S.
(Environmental Surcharge)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., T
L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L. T

RATE.

The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph ~~3~~ 2 below and in the current period as provided in Paragraph 3 below. N N

The retail share of the revenue requirement will be allocated between residential and non-residential retail customers based upon their respective total revenues during the previous calendar year. The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers. N T

1. Monthly Environmental Surcharge Gross Revenue Requirement, E(m) T

Where:	E(m)	=	CRR - BRR
	CRR	=	Current Period Revenue Requirement for the Expense Month.
	BRR	=	Base Period Revenue Requirement.

2. Base Period Revenue Requirement, BRR T

BRR = The Following Monthly Amounts:

Billing Month	Base Net Environmental Costs	
JANUARY	$ 2,750,919	R
FEBRUARY	2,738,884	R
MARCH	2,851,531	R
APRIL	2,909,965	R
MAY	2,897,250	R
JUNE	2,835,973	R
JULY	3,567,407	R
AUGUST	3,319,549	R
SEPTEMBER	3,378,515	R
OCTOBER	3,097,929	R
NOVEMBER	2,994,579	I
DECEMBER	2,996,160	R
	$ 36,338,660	R

(Continued on Sheet 29-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 2, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Mitchell FGD and all related associated costs are not included in base rates or the Base Revenue Requirement but will be included in the Current Period Revenue Requirement. The Mitchell FGD will be excluded from Base Rates at least until June 30, 2020. N N

3. Current Period Revenue Requirement, CRR T

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} + [((RB_{IM(c)}) (ROR_{IM(c)})/12) + OE_{IM(c)}] (.15) - AS]$$

Where:

$RB_{KP(C)}$	=	Environmental Compliance Rate Base for Mitchell. T
$ROR_{KP(C)}$	=	Annual Rate of Return on Mitchell Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return. T
$OE_{KP(C)}$	=	Monthly Pollution Control Operating Expenses for Mitchell. T
$RB_{IM(C)}$	=	Environmental Compliance Rate Base for Rockport.
$ROR_{IM(C)}$	=	Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{IM(C)}$	=	Monthly Pollution Control Operating Expenses for Rockport.
AS	=	Net proceeds from the sale of Title IV and CSAPR SO_2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. T

"KP(C)" identifies components from Mitchell Units – Current Period, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period. T

The Rate Base for both Kentucky Power and Rockport should reflect the current costs associated with the 1997 Plan, ~~and~~ the 2003 Plan, the 2005 Plan, the 2007 Plan and the 2014 Plan. The Rate Base for Kentucky Power should also include a cash working capital allowance based on the 1/8 formula approach, due to the inclusion of Kentucky Power's accounts receivable financing in the capital structure and weighted average cost of capital. The Operating Expenses for both Kentucky Power and Rockport should reflect the current operating expenses associated with the 199 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, and the 2014 Plan. T T

The Rate of Return for Kentucky Power is 10.62% rate of return on equity as authorized by the Commission in its Order Dated XXXXXXXXX in Case No. 2014-00396. T T

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

(Cont'd on Sheet 29-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

4. Revenue Allocation N

$$\text{Residential Allocation RA(m)} = \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(m)} = \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:
(m) = the expense month
(b) = most recent calendar year revenues

5. Environmental Surcharge Factor

$$\text{Residential Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)} * \text{RA(m)}}{\text{KY RR(m)}}$$

$$\text{All Other Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)} * \text{AO(m)}}{\text{KY OR(m)- KY OF(m)}}$$

Where:
Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/ (Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non -Physical Revenues.)

RR(m) = Kentucky Residential Retail Revenues for the Expense Month.

OR(m) = Kentucky All Other Classes Retail Revenues for the Expense Month

OF(m) = Kentucky All Other Classes Fuel Revenues for the Expense Month N

(Cont'd on Sheet No. 29-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-4
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 29-4

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

6. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows: T

Total Company:

- return on Title IV and CASPR SO_2 allowance inventory T
- over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge T
- costs associated with any Commission's consultant approved by the Commission T
- costs associated with the consumption Title IV and CSAPR of SO_2 allowances T
- costs associated with the consumption of NO_x allowances T
- return on NO_x allowance inventory T
- costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor) T
- Costs associated with consumables used in conjunction with approved environmental projects. T

The Company's share of costs associated with the following environmental equipment at the Rockport Plant: N

- Continuous Emissions Monitors
- Air Emission Fees
- Costs Associated with the Rockport Unit Power Agreement
- Activated Carbon Injection
- Mercury Monitoring
- Precipitator Modifications
- Dry Sorbent Injection
- Coal Combustion Waste Landfill
- Low NOx burners, over-fire air, Landfill N

(Cont'd on Sheet No. 29-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-5
CANCELLING P.S.C. KY. NO. 10 ________SHEET NO. 29-5

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

The Company's share of costs associated with the following environmental equipment at the Mitchell Plant: N

- Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners, Low NO_x burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities
- Air Emission Fees N
- Precipitator Modifications and Upgrades
- Coal Combustion Waste Landfill
- Bottom Ash and Fly Ash Handling
- Mercury Monitoring (MATS)
- Dry Fly Ash Handling Conversion N

7. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 DATED XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 30- 1
CANCELLING P.S.C. KY. NO. 10 __________ SHEET NO. 30- 1

RESERVED FOR FUTURE USE T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 30-3
CANCELLING P.S.C. KY. NO. 10 __________ SHEET NO. 30-3

RESERVED FOR FUTURE USE T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 30-4**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 30-4

RESERVED FOR FUTURE USE T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER G.P.O.
(Green Pricing Option Rider)

AVAILABILITY OF SERVICE.

Available to customers taking metered service under the Company's R.S., R.S.-L.M.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P. and M.W. tariffs. T

Participation in this program may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants.

CONDITIONS OF SERVICE.

Customers who wish to support the generation of electricity by Renewable Resources may contract to purchase each month a specific number of fixed kWh blocks, where each block equals 100 kWh. Customers may elect to purchase a minimum of one (1) block per month and a maximum of 500 blocks per month.

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. Only Renewable Resources brought into service on or after January 1, 1997 shall qualify.

RATE.

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for each fixed kWh block under contract regardless of the customer's actual energy consumption during that month. The charge will be applied to the customer's bill as a separate line item.

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

Charge ($ per 100 kWh block): $ 2.00/month

TERM.

This is a voluntary program. Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable.

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Green Pricing Option Rider will be used solely to purchase RECs for the program.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER A.F.S.
(Alternate Feed Service Rider)

AVAILABILITY OF SERVICE.

Standard Alternate Feed Service (AFS) is a premium service providing a redundant distribution service provided through a redundant distribution line and distribution station transformer, with automatic or manual switch-over and recovery, which provides increased reliability for distribution service. Rider AFS applies to those customers requesting new or upgraded AFS after the effective date of this rider. Rider AFS also applies to existing customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service.

Rider AFS is available to customers who request a primary voltage alternate feed and who normally take service under Tariffs M.G.S., M.G.S. TOD, L.G.S., L.G.S.-TOD, I.G.S., or M.W. for their basic service requirements, provided that the T
Company has adequate capacity in existing distribution facilities, as determined by the Company, or if changes can be made to make capacity available. AFS provided under this rider may not be available at all times, including emergency situations.

SYSTEM IMPACT STUDY CHARGE.

The Company shall charge the customer for the actual cost incurred by the Company to conduct a system impact study for each site reviewed. The study will consist of, but is not limited to, the following: (1) identification of customer load requirements, (2) identification of the potential facilities needed to provide the AFS, (3) determination of the impact of AFS loading on all electrical facilities under review, (4) evaluation of the impact of the AFS on system protection and coordination issues including the review of the transfer switch, (5) evaluation of the impact of the AFS request on system reliability indices and power quality, (6) development of cost estimates for any required system improvements or enhancements required by the AFS, and (7) documentation of the results of the study. The Company will provide to the customer an estimate of charges for this study.

EQUIPMENT AND INSTALLATION CHARGE.

The customer shall pay, in advance of construction, a nonrefundable amount for all equipment and installation costs for all dedicated and/or local facilities provided by the Company required to furnish either a new or upgraded AFS. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. The customer will not acquire any title in said facilities by reason of such payment. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, the following: (1) all costs associated with the AFS dedicated and/or local facilities provided by the Company and (2) any costs or modifications to the customer's basic service facilities.

The customer is responsible for all costs associated with providing and maintaining phone service for use with metering to notify the Company of a transfer of service to the AFS or return to basic service.

TRANSFER SWITCH PROVISION.

In the event the customer receives basic service at primary voltage, the customer shall install, own, maintain, test, inspect, operate and replace the transfer switch. Customer-owned switches are required to be at primary voltage and must meet the Company's engineering, operational and maintenance specifications. The Company reserves the right to inspect the customer-owned switches periodically and to disconnect the AFS for adverse impacts on reliability or safety.

(Cont'd on Sheet No. 32-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER A.F.S.
(Alternate Feed Service Rider)

TRANSFER SWITCH PROVISION (CONTINUED).

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer shall pay a monthly rate of $14.25 for the Company to annually test the transfer switch / control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module. I

In the event a customer receives basic service at secondary voltage and requests AFS, the Company will provide the AFS at primary voltage. The Company will install, own, maintain, test, inspect and operate the transfer switch and control module. The customer shall pay the Company a nonrefundable amount for all costs associated with the transfer switch installation. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer is required to pay the monthly rate for testing and ongoing maintenance costs defined above. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes.

After a transfer of service to the AFS, a customer utilizing a manual or semi-automatic transfer switch shall return to the basic service within one (1) week or as mutually agreed to by the Company and customer. In the event system constraints require a transfer to be expedited, the Company will endeavor to provide as much advance notice as possible to the customer. However, the customer shall accomplish the transfer back to the basic service within ten minutes if notified by the Company of system constraints. In the event the customer fails to return to basic service within 12 hours, or as mutually agreed to by the Company and customer, or within ten minutes of notification of system constraints, the Company reserves the right to immediately disconnect the customer's load from the AFS source. If the customer does not return to the basic service as agreed to, or as requested by the Company, the Company may also provide 30 days' notice to terminate the AFS agreement with the customer.

The customer shall make a request to the Company for approval three days in advance for any planned switching.

MONTHLY AFS CAPACITY RESERVATION DEMAND CHARGE.

Monthly AFS charges will be in addition to all monthly basic service charges paid by the customer under the applicable tariff.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is $6.25 per kW. I

AFS CAPACITY RESERVATION.

The customer shall reserve a specific amount of AFS capacity equal to, or less than, the customer's normal maximum requirements, but in no event shall the customer's AFS capacity reservation under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

(Cont'd on Sheet No. 32-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER A.F.S.
(Alternate Feed Service Rider)

AFS CAPACITY RESERVATION (continued).

If the customer plans to increase the AFS demand at anytime in the future, the customer shall promptly notify the Company of such additional demand requirements. The customer's AFS capacity reservation and billing will be adjusted accordingly. The customer will pay the Company the actual costs of any and all additional dedicated and/or local facilities required to provide AFS in advance of construction and pursuant to an AFS construction agreement. If customer exceeds the agreed upon AFS capacity reservation, the Company reserves the right to disconnect the AFS. If the customer's AFS metered demand exceeds the agreed upon AFS capacity reservation, which jeopardizes company facilities or the electrical service to other customers, the Company reserves the right to disconnect the AFS immediately. If the Company agrees to allow the customer to continue AFS, the customer will be required to sign a new AFS agreement reflecting the new AFS capacity reservation. In addition, the customer will promptly notify AEP regarding any reduction in the AFS capacity reservation.

The customer may reserve partial-load AFS capacity, which shall be less than the customer's full requirements for basic service subject to the conditions in this provision. Prior to the customer receiving partial-load AFS capacity, the customer shall be required to demonstrate or provide evidence to the Company that they have installed demand-controlling equipment that is capable of curtailing load when a switch has been made from the basic service to the AFS. The Company reserves the right to test and verify the customer's ability to curtail load to meet the agreed upon partial-load AFS capacity reservation.

DETERMINATION OF BILLING DEMAND.

Full-Load Requirement:

For customers requesting AFS equal to their load requirement for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly billing demand on the AFS during the past 11 months, or (c) the customer's basic service capacity reservation, or (d) the customer's highest previously established monthly billing demand on the basic service during the past 11 months.

Partial-Load Requirement:

For customers requesting partial-load AFS capacity reservation that is less than the customer's full requirements for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak on the AFS as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly metered demand on the partial-load AFS during the past 11 months.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

(Cont'd on Sheet No. 32-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER A.F.S.
(Alternate Feed Service Rider)

TERMS OF CONTRACT.

The AFS agreement under this rider will be made for a period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this rider.

Disconnection of AFS under this rider due to reliability or safety concerns associated with customer-owned transfer switches will not relieve the customer of payments required hereunder for the duration of the agreement term.

SPECIAL TERMS AND CONDITIONS.

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

Upon receipt of a request from the customer for non-standard AFS (AFS which includes unique service characteristics different from standard AFS), the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. An AFS agreement will be filed with the Commission under the 30-day filing procedures. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

The Company assumes no liability should the AFS circuit, transfer switch, or other equipment required to provide AFS fail to operate as designed, is unsatisfactory, or is not available for any reason.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

U.G.R.T.
(Utility Gross Receipts Tax)
(School Tax)

APPLICABLE.

To all Tariff Schedules.

RATE.

This tariff schedule is applied as a rate increase pursuant to KRS 160.617 to all other tariff schedules for the recovery by the utility of the utility gross receipts license tax imposed by the applicable school district pursuant to KRS 160.613 with respect to the customer's bill. The current utility gross receipts license tax for school imposed by a school district may not exceed 3%. The utility gross receipts license tax shall appear on the customer's bill as a separate line item.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

K.S.T.
(Kentucky Sales Tax)

APPLICABLE.

To all Tariff Schedules.

RATE.

This tariff schedule is applied as a rate increase to all other applicable tariff schedules for the recovery by the utility pursuant to KRS 139.210 of the Kentucky Sales Tax imposed by KRS 139.200 for all customers not exempted by KRS 139.470(8). For any other exempt customers, an exemption certification must be received and on file with the Company. The Kentucky Sales Tax rate is currently imposed by the Commonwealth of Kentucky at the rate of 6%. The Kentucky Sales Tax shall appear on the customer's bill as a separate line item.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF P.P.A.
(Purchase Power Adjustment)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L. and S.L. T T

RATE.

1. In accordance with the Stipulation and Settlement Agreement approved as modified by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the purchase power adjustment shall provide for monthly adjustments based on a percent of revenues, calculated to six decimal places and equal to the net costs of any power purchases in the current period according to the following formula:

$$\text{Monthly Purchase Power Adjustment Factor} = \frac{\text{Net KY Retail P(m)}}{\text{KY Retail R(m)}}$$

Where:

Net KY Retail P(m) = Monthly P(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month (m). (For purposes of this formula, Total Company Revenues include only Retail and Full-Requirements Wholesale revenues.)

KY Retail R(m) = Kentucky Retail Revenues for the Expense Month (m).

2. The net costs of any power purchased shall exclude costs recovered through the Fuel Adjustment Clause and shall be computed as the sum of the following items:

   a. PPA(m) = The cost of power purchased by the Company through new Purchase Power Agreements (PPAs). All new PPAs shall be approved by the Commission to the extent required by KRS 278.300.
   b. RP(m) = The cost of fuel related substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages.
   c. PE(m)= The cost of power purchased unrelated to forced generation or transmission outages that are calculated in accordance with the peaking unit equivalent methodology. N
   d. CSIRP(m) = The cost of any credits provided to customers under Tariff C.S.-I.R.P. for interruptible service.

   Monthly P(m) = PPA(m) + RP(m)+PE(m) + CSIRP(m) T

3. The monthly purchase power adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment, which shall include data, and information as may be required by the Commission.

4. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 36-1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 36-1

TARIFF A.T.R.
(Asset Transfer Rider)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S. , C.S.- I.R.P., M.W., O.L. and S.L. T T

RATE.

In accordance with the Stipulation and Settlement Agreement approved as modified by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, Kentucky Power Company is to recover from retail ratepayers $44 million annually beginning January 1, 2014. T

Recovery under Tariff A.T.R. shall terminate on the effective date of new base rates for the Company that include Mitchell Units 1 and 2, except that the Company shall recover through the Residential Asset Transfer Adjustment and the All Other Classes Transfer Adjustment such amounts as required to ensure the Company recovers in the year new base rates for the Company are established that include Mitchell Units 1 and 2 a pro rata share (computed on a 365-day annual basis) of the $44 million annual revenue requirement under Tariff A.T.R.. N N

1. The allocation of the $44 million revenue requirement between residential and all other customers shall be based upon their respective contribution to total retail revenues for the twelve month period ended September 30, 2013, according to the following formula:

$$\text{Residential Allocation RA(m)} = \frac{\$44{,}000{,}000}{\text{12 months}} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}} = \$1{,}541{,}861$$

$$\text{All Other Allocation OA(m)} = \frac{\$44{,}000{,}000}{\text{12 months}} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}} = \$2{,}124{,}806$$

Where:
(m) = the expense month;
(b) = twelve month period ended September 30, 2013.

RR(b) = $214,421,664
OR(b) = $295,489,874
R(b) = $509,911,538

2. The Residential Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of total revenues, calculated to six decimal places according to the following formula:

$$\text{Residential Asset Transfer Adjustment Factor} = \frac{\text{Net Monthly Residential Allocation NRA(m)}}{\text{Residential Retail Revenue RR(m)}}$$

Where:
Net Monthly Residential Allocation NRA(m) = Monthly Residential Allocation RA(m), net of Over/(Under) Recovery Adjustment;

Residential Retail Revenue RR(m) = Monthly Retail Revenue for all KY residential classes for the expense month (m).

3. The All Other Classes Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of non-fuel revenues, calculated to six decimal places according to the following formula:

$$\text{All Other Classes Asset Transfer Adjustment Factor} = \frac{\text{Net Monthly All Other Allocation NOA(m)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(m)}}$$

Where:
Net Monthly All Other Allocation NOA(m) = Monthly All Other Allocation OA(m), net of Over/(Under) Recovery Adjustment;

All Other Classes Non-Fuel Retail Revenue ONR(m) = Monthly Non-Fuel Retail Revenue for all classes other than residential for the expense month (m).

(Cont'd on Sheet 36-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF A.T.R.
(Asset Transfer Rider)

RATE. (Cont'd)

5. The monthly asset transfer rider adjustments shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

TARIFF E.D.R.
(Economic Development Rider)

N

AVAILABILITY OF SERVICE.

To encourage economic development in the Company's service territory, limited-term reductions in billing demand charges described herein are offered to qualifying new and existing retail customers who make application for service under this Rider.

Service under this Economic Development Rider (EDR) is intended for specific types of commercial and industrial customers whose operations, by their nature, will promote sustained economic development based on plant and facilities investment and job creation. Availability is limited to customers on a first-come, first-served basis until such time as a total of 250 MW of new load has been added to Kentucky Power's system under the EDR. The EDR is available to commercial and industrial customers served under Tariffs L.G.S., Q.P. or C.I.P.-T.O.D. who meet the following requirements:

(1) A new customer must have at least a monthly maximum billing demand of 500 kW. An existing customer must increase its monthly maximum billing demand by at least 500 kW over the current Base Maximum Billing Demand in order to receive the Incremental Billing Demand Discount (IBDD).

(2) A new customer, or the business expansion by an existing customer, will receive a Supplemental Billing Demand Discount (SBDD) for creating and sustaining at least 25 new permanent full time jobs over the contract term at the service location. The Company reserves the right to verify job counts. Failure to demonstrate the creation of new employment positions or to maintain the employment during the contract term will result in the termination of the supplemental discount.

(3) The customer must demonstrate to the Company's satisfaction that, absent the availability of this EDR, the qualifying new or increased electrical demand would be located outside of the Company's service territory or would not be placed in service.

TERMS AND CONDITIONS.

(1) The Company will offer the EDR to qualifying customers with new or increased load when the Company has sufficient generating capacity available. When sufficient generating capacity is not available, the Company will procure the additional capacity on the customer's behalf. The cost of capacity procured on behalf of the customer shall reduce on a dollar-for-dollar basis the customer's IBDD and SBDD. Such reduction shall be capped so that the customer's maximum demand charge shall be the non-discounted tariff demand charge. The reduction will be applied in reverse chronological order beginning with the most recent customer to receive discounted service under this tariff. Last customer to sign up for the EDR tariff would be the first customer responsible for paying the cost of incremental capacity purchases. In any year during the discount period in which the customer pays the full tariff demand charge for all twelve months, the Company will reduce the term of the contract by one year.

(2) The new or increased load cannot accelerate the Company's plans for additional generating capacity during the period for which the customer receives a demand discount. Customers receiving Temporary Service are not eligible for this EDR.

(3) To receive service under this EDR, the customer shall make written application to the Company with sufficient information contained therein to determine the customer's eligibility for service. At a minimum, such information will include:

N

(Cont'd on Sheet 37-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

N

TARIFF E.D.R. (Cont'd)
(Economic Development Rider)

TERMS AND CONDITIONS-(Cont'd).

a. A description and good faith estimate of the new or increased load to be served during each year of the contract,
b. The number of new employees or jobs that will be added as a result of the new load,
c. A description of the anticipated capital investment, and
d. A description of all other federal, state or local economic development tax incentives, grants, or any other incentives / assistance associated with the new or expanded project.
e. A statement that without the EDR discount, the customer would locate elsewhere or chose not to expand within Kentucky Power's service territory.

(3) For new and existing customers, billing demands for which reductions will be for service at a new service location or expanded production at an existing facility and not merely the result of a change of ownership. Relocation of the delivery point of the Company's service, moving existing equipment from another KPCo-served location or load transfers from another KPCo-served location do not qualify as a new service location. Relocating existing facilities from within the Company's service territory shall not disqualify the customer from the IBDD as long as the new relocated facility exceeds the Base Maximum Billing Demand of the previous facility by the minimum required amount.

(4) For existing customers, billing demands for which deductions will be applicable under this EDR shall be the result of an increase in business activity and not merely the result of resumption of normal operations following a force majeure, strike, equipment failure, renovation or refurbishment, or other such abnormal operating condition. In the event that such an occurrence has taken place prior to the date of the application by the customer for service under this EDR, the monthly Base Maximum Billing Demand shall be adjusted as appropriate for this analysis to eliminate the effects of such occurrence.

(5) Service under the EDR will be offered under the applicable Tariff L.G.S., Q.P. or C.I.P.-T.O.D schedule. An EDR will be filed as a Special Contract and must be approved by the Kentucky Public Service Commission before it can be implemented. The total contract period is equal to twice the number of years for which the customer receives a demand discount. The special contract term will be for two (2), four (4), six (6), eight (8), and (ten) 10 years only.

(6) The IBDD and the SBDD, if applicable, begin when the customer's new or expanded operations are billed for service under this Rider. Temporary jobs created during the construction of new facilities or the expansion phase of existing operations are not eligible to be counted as permanent jobs for the purposes of this EDR.

(7) If construction of new or expanded local distribution and/or transmission related facilities by the Company is required in order to provide the additional service, the customer may be required to make a contribution-in-aid of construction (CIAC) for the installed cost of such facilities pursuant to the provisions of the Company's Terms and Conditions of Service. The total cost of the CIAC, including gross-up by the effect of applicable taxes, will be recovered over the life of the EDR contract period, with no less than 80% recovered during the period for which the customer receives a demand discount. If the customer breaches the terms of the contract or ends the contract prematurely, any unpaid contribution-in-aid of construction must be paid to the Company and any EDR discounts provided to the customer must be repaid to the Company. CIAC payment provided under this Rider supersedes the other payment provisions only in the Company's Terms and Conditions Sheet 2-5 Section 9. N

(Cont'd on Sheet 37-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.D.R. (Cont'd)
(Economic Development Rider)

N

TERMS AND CONDITIONS (Cont'd).

(8) The L.G.S., Q.P. and CIP-TOD tariffs each contain a monthly minimum billing demand charge provision. The minimum demand charge provision is waived for EDR customers for up to 36 months depending upon the length of the contract. The provision is waived for the first 36 months of a 10 year contract, the first 24 months of an 8 year contract and the first 12 months of a 6 year contract. If during the special contract discount period, the customer's monthly demand falls below the minimum billing demand level for four (4) consecutive months or six (6) months total in a contract year, then the EDR discount will not be applied and the appropriate tariff minimum billing demand charge provision will be in force until the customer achieves the minimum billing demand level. Applicable EDR discounts will be applied to the qualifying incremental maximum billing demand only and will appear as a separate line item on the customer's bill.

DETERMINATION OF MONTHLY QUALIFYING INCREMENTAL BILLING DEMAND.

For the purposes of this Rider, the monthly qualifying incremental billing demand will be calculated in the following manner:

Where the new qualifying incremental demand resides in new facilities (or separate facilities for existing customers), those facilities may be metered on a separate meter according to Tariffs L.G.S., Q.P. or C.I.P.-T.O.D. for the current billing period and the incremental billing demand will be calculated based upon that facility's meter readings.

Where the new qualifying incremental demand resides in a customer's existing facility with sufficient service and metering capability to accommodate the business expansion, the qualifying incremental billing demand is equal to demand in excess of the Base Maximum Billing Demand. The Base Maximum Billing Demand for each billing month will be calculated by the Company as the average of the previous three years, corresponding month maximum billing demands, subject to Terms and Conditions Items (3) and (4), and will be agreed to by the customer in advance.

DETERMINATION OF INCREMENTAL BILLING DEMAND DISCOUNT.

Customers meeting all Availability of Service and Terms and Conditions above may contract for service for a period of up to ten (10) years, with a commensurate discount period of up to five (5) years. The (IBDD) for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced by 50% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. demand charge;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced by 40% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. demand charge;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced by 30% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. demand charge; N

(Cont'd on Sheet 37-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.D.R. (Cont'd)
(Economic Development Rider)

N

DETERMINATION OF INCREMENTAL BILLING DEMAND DISCOUNT (Cont'd).

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced by 20% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. charge, but shall not be less than the applicable tariff rate schedule minimum billing demand;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced by 10% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand; and

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10).

The starting point for the IBDD is dependent upon the length of contract: i.e., an eight (8) year contract will have four (4) years of discount beginning with the IBDD of 40% in year one (1). Similarly, a six (6) year contract will have three (3) years of discount beginning with the IBDD of 30% in year one (1).

DETERMINATION OF SUPPLEMENTAL BLLING DEMAND DISCOUNT.

At the Company's discretion, a (SBDD) which is applicable to the monthly incremental billing demand charge is available to customers meeting all Availability of Service and Terms and Conditions above, and that create at least twenty five (25) new permanent job opportunities in the facility and that maintain those job opportunities in each discount year. The amount of additional discount is determined by the actual number of jobs maintained in each year. The SBDD for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced an additional 5% for an increase of at least 50 jobs or 2.5% for an increase of at least 25 jobs;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced 4.5% for at least 50 jobs or 2.0% for at least 25 jobs.

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced an additional 4% for an increase of at least 50 jobs or 1. 5% for an increase of at least 25 jobs;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3.5% for an increase of at least 50 jobs or 1. 0% for an increase of at least 25 jobs;

N

(Cont'd on Sheet 37-5)

N

TARIFF E.D.R. (Cont'd)
(Economic Development Rider)

DETERMINATION OF SUPPLEMENTAL BLLING DEMAND DISCOUNT (Cont'd).

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3% for an increase of at least 50 jobs or 0.5% for an increase of at least 25 jobs; and

(f) All subsequent monthly billing shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10)

The length of the SBDD shall be identical to the length of the IBDD. The starting point for the discount will be commensurate with the contract length, i.e., an eight (8) year contract will have four (4) years of discount with the SBDD of either 4.5% or 2.0% as appropriate in year one (1).

The appropriate discount(s) shall be applicable over a period of up to 60 consecutive billing months beginning with the first such month following the end of the start-up period. The start-up period shall commence with the effective date of the contract addendum for service under this EDR and shall terminate by mutual agreement between the Company and the customer. In no event shall the start-up period exceed 12 months.

TERMS OF CONTRACT.

A contract or agreement addendum for service under this Rider, in addition to service under Tariffs L.G.S., Q.P. or C.I.P.-T.O.D., shall be executed by the customer and the Company for the time period which includes the start-up period and the multi-year period during which a Total Demand Charge discount is in effect and an equal multi-year period during which the customer agrees to pay the full rates in the applicable Tariff rate schedule.

At a minimum, the contract or agreement addendum shall specify the Base Maximum Billing Demand, the anticipated annual total qualifying demand, the Adjustment Factor and related provisions to be applicable under this Rider, and the effective date for the contract addendum.

The customer may discontinue service under this Rider before the end of the contract or agreement addendum only by reimbursing the Company for any and all demand reductions received under this Rider when billed at the applicable tariff schedule rate.

SPECIAL TERMS AND CONDITIONS.

Except as otherwise provided in this Rider, written agreements shall remain subject to all of the provisions of the applicable tariffs. This Rider is subject to the Company's Terms and Conditions of Service.

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 38-1
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 38-1

N

BIG SANDY RETIREMENT RIDER
(B.S.R.R.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L. and S.L.

RATE.

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) carrying cost over a 25 year period beginning when new base rates are set for the Company that include Mitchell Units 1 and 2. The term "Retirement Costs" as used in this agreement are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.

2. The allocation of the levelized revenue requirement (LRR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent calendar twelve month period, according to the following formula:

$$\text{Residential Allocation RA(m)} = \text{LRR(m)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(m)} = \text{LRR(m)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:
(m) = the expense month;

(b) = Most recent available twelve calendar-month period ended December 31.

3. The Residential Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential Asset Transfer Adjustment Factor} = \frac{\text{Net Monthly Residential Allocation NRA(m)}}{\text{Residential Retail Revenue RR(m)}}$$

Where:
Net Monthly Residential Allocation NRA(m) = Monthly Residential Allocation RA(m), net of Over/(Under) Recovery Adjustment;

Residential Retail Revenue RR(m) = Monthly Retail Revenue for all KY residential classes for the expense month (m).

N

(Cont'd on Sheet No. 38-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

BIG SANDY RETIREMENT RIDER(CONT'D)
(B.S.R.R.) N

RATE. (Cont'd)

4. The All Other Classes Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of non-fuel revenues, according to the following formula:

All Other Classes Asset Transfer Adjustment Factor	=	Net Monthly All Other Allocation NOA(m) / All Other Classes Non-Fuel Retail Revenue ONR(m)

Where:

Net Monthly All Other Allocation NOA(m)	=	Monthly All Other Allocation OA(m), net of Over/(Under) Recovery Adjustment;
All Other Classes Non-Fuel Retail Revenue ONR(m)	=	Monthly Non-Fuel Retail Revenue for all classes other than residential for the expense month (m).

5. The monthly Big Sandy Retirement Rider adjustments shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 39-1
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 39-1

N

BIG SANDY UNIT 1 OPERATION RIDER
(B.S.1.O.R.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES.

Tariff Class	\$/kWh	\$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	\$0.00330	--
S.G.S. and S.G.S.-T.O.D.	\$0.00272	--
M.G.S.	\$0.00141	\$0.34
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	\$0.00283	--
L.G.S. and L.G.S.-T.O.D.	\$0.00139	\$0.45
L.G.S.-L.M.-T.O.D.	\$0.00276	--
I.G.S. and C.S.-I.R.P.	\$0.00139	\$0.55
M.W.	\$0.00248	--
O.L.	\$0.00147	--
S.L.	\$0.00147	--

Tariff BS1OR includes all non-fuel operating expenses related to Big Sandy Unit 1 not otherwise included in Tariff S.S.C. or Tariff FAC. Tariff BS1OR shall also include a return on and of Big Sandy Unit 1 gas conversion capital when placed in service.

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS and IGS tariff classes.

The Big Sandy Unit 1 Operation Rider factors shall be modified annually to collect the approved annual level of Kentucky retail jurisdictional Big Sandy Unit 1 revenue requirement and any prior review period (over)/under recovery.

The Big Sandy Unit 1 Operation Rider factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{BS1E \times (BE_{Class} / BE_{Total}) + BS1D \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{BS1E \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{BS1D \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

(Cont'd on Sheet No.39-2)

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 39-2**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 39-2

BIG SANDY UNIT 1 OPERATION RIDER (CONT'D)
(B.S.1.O.R)

N

RATES. (Cont'd)

Where:

1. "BS1D" is the actual annual retail Big Sandy Unit 1 demand-related costs, plus any prior review period (over)/under recovery.
2. "BS1E" is the actual annual retail Big Sandy Unit 1 energy-related costs, plus any prior review period (over)/under recovery.
3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
(1)	(2)	(3)	(4)=(2)x(3)
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.I 2		0.0236060%	
S.G.S and S.G.S.-T.O.D.		0.0163937%	
M.G.S.		0.0177002%	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		0.0177002%	
L.G.S.and L.G.S.-T.O.D.		0.0169381%	
L.G.S.-L.M.-T.O.D.		0.0169381%	
I.G.S. and C.S.-I.R.P		0.0130626%	
M.W.		0.0134057%	
O.L.		0.0009431%	
S.L.		0.0009890%	
	BE_{Total}		CP_{Total}

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.
7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.

The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the Big Sandy Unit 1 Operation Rider revenues.

The annual Big Sandy Unit 1 Operation Rider factors shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 40-1
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 40-1

N

NERC COMPLIANCE AND CYBERSECURITY RIDER
(N.C.C.R.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES.

Tariff Class	¢/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	0.0000	--
S.G.S. and S.G.S.-T.O.D.	0.0000	--
M.G.S.	0.0000	0.00
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	0.0000	--
L.G.S. and L.G.S.-T.O.D.	0.0000	0.00
L.G.S.-L.-M.T.O.D.	0.0000	0.00
I.G.S. and C.S.-I.R.P.	0.0000	0.00
M.W.	0.0000	--
O.L.	0.0000	--
S.L.	0.0000	--

The kWh adjustment factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW adjustment factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS and IGS tariff classes.

The NERC Compliance and Cybersecurity Rider adjustment factors shall be modified annually to collect the Commission's approved annual level of Kentucky retail jurisdictional NERC Compliance and Cybersecurity expenses and any prior review period (over)/under recovery.

The NERC Compliance and Cybersecurity Rider adjustment factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Adjustment Factor} = \frac{NCE \times (BE_{Class} / BE_{Total}) + NCD \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Adjustment Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Adjustment Factor} = \frac{NCE \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Adjustment Factor} = \frac{NCD \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

N

(Cont'd on Sheet No. 40-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

N

NERC COMPLIANCE AND CYBERSECURITY RIDER (CONT'D)
(N.C.C.R.)

RATES: (Cont'd)

Where:

1. "NCD" is the actual annual retail NERC Compliance and Cybersecurity demand-related costs, plus any prior review period (over)/under recovery.

2. "NCE" is the actual annual retail NERC Compliance and Cybersecurity energy-related costs, plus any prior review period (over)/under recovery.

3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.

4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
(1)	(2)	(3)	(4)=(2)x(3)
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2		0.0236060%	
S.G.S. and S.G.S.-T.O.D.		0.0163937%	
M.G.S.		0.0177002%	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		0.0177002%	
L.G.S.and L.G.S.-T.O.D.		0.0169381%	
L.G.S.-L.M.-T.O.D.		0.0169381%	
I.G.S. and C.S.-I.R.P.		0.0130626%	
M.W.		0.0134057%	
O.L.		0.0009431%	
S.L.		0.0009890%	
	BE_{Total}		CP_{Total}

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.

7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.

The adjustment factor as computed above shall be further modified to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the NERC Compliance and Cybersecurity Rider adjustment revenues. N

(Cont'd on Sheet No. 40-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

**NERC COMPLIANCE AND CYBERSECURITY RIDER (CONT'D)
(N.C.C.R.)**

N

RATES. (Cont'd)

The initial NERC Compliance and Cybersecurity Rider adjustment factors shall be filed with the Commission six (6) months before the initial rates are scheduled to go into effect and ten (10) days before any subsequent annual rate adjustments are scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

P.S.C KY. NO. 10 N

KENTUCKY POWER COMPANY
101A ENTERPRISE DRIVE
P.O. BOX 5190
FRANKFORT, KY 40602

RATES-CHARGES-RULES-REGULATIONS
FOR FURNISHING

ELECTRIC SERVICE

IN THE KENTUCKY TERRITORY SERVED
BY KENTUCKY POWER COMPANY
AS STATED ON SHEET NO. 1

FILED WITH THE PUBLIC SERVICE COMMISSION
OF
KENTUCKY

DATE OF ISSUE: December 23, 2014
DATE EFFECTIVE: January 23, 2015
ISSUED BY: John A. Rogness III
TITLE: Director Regulatory Services N

INDEX

(Cont'd on Sheet No. 1-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 1-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 1-2

INDEX (Cont'd)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-Xxxx Dated Xxxxxxxx

INDEX (Cont'd)

THE ABOVE TARIFFS ARE APPLICABLE TO THE ENTIRE TERRITORY SERVED BY KENTUCKY POWER COMPANY IN BOYD, BREATHITT, CARTER, CLAY, ELLIOTT, FLOYD, GREENUP, JOHNSON, KNOTT, LAWRENCE, LESLIE, LETCHER, LEWIS, MAGOFFIN, MARTIN, MORGAN, OWSLEY, PERRY, PIKE AND ROWAN COUNTIES.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-Xxxx Dated Xxxxxxxx

TERMS AND CONDITIONS OF SERVICE

1. **APPLICATION.**

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request and the Customer shall elect upon which tariff applicable to his service his application shall be based. *A copy of the tariff is also available on-line at www.kentuckypower.com.* N

If the Company requires a written agreement from a Customer before service will be commenced, a copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. **INSPECTION.**

The Customer is responsible for the proper installation and maintenance of the customer's wiring and electrical equipment and the customer shall at all times be responsible for the character and condition thereof. The Company has no obligation to undertake inspection thereof and in no event shall be responsible therefore. However, the Company may refuse to connect to the customer's system if such connection is deemed unsafe by the Company.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until the Company has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and/or tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefore. No responsibility shall attach to the Company because of any waiver of this requirement.

3. **SERVICE CONNECTIONS.**

Service connections will be provided in accordance with 807 KAR 5:041, Section 10.

The Customer should in all cases consult the Company before the Customer's premises are wired to determine the location of Company's point of service connection.

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain equipment specified by the Company, the Company may supply or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building.

All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

(Cont'd on Sheet No. 2-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

4. DEPOSITS.

Prior to providing service or at any time thereafter, the Company may require a cash deposit or other guaranty *acceptable to the Company* to secure payment of bills except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section *16*, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained *by the Company* during the entire time that the account remains active. T T

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied by the Company as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention of any deposit or guaranty by the Company prior to final settlement is not a payment or partial payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria, which ~~shall~~ *may* be considered by the Company cumulatively. T

1. ~~Satisfactory payment history.~~ *Satisfactory payment criteria, which may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments and having no meter diversion or theft of service.* T T
2. ~~Statement from another utility showing satisfactory payment history.~~ *Meeting satisfactory credit criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources as well as historic and ongoing payment and credit history with Company.* T
3. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit.
4. Providing evidence of other collateral acceptable to Company. ~~*such as Surety Bond.*~~ T
5. ~~*Checkless Payment Plan (CPP)*~~ T

C. Method of Determination

1. Calculated Deposits

a. Deposit amounts paid by residential customers shall not exceed a calculated amount based upon actual usage data of the Customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the Customer's actual or estimated annual bill.

b. Deposit amounts paid by commercial and industrial customers shall not exceed a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill.

(Cont'd on Sheet No. 2-3)

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-3
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-3

TERMS AND CONDITIONS OF SERVICE (Cont'd)

4. DEPOSITS, (Cont'd.)

D. Additional or Supplemental Deposit Requirement

~~If a deposit has been waived or returned and the Customer fails to maintain satisfactory payment criteria, the Customer may be~~ T
~~required to pay an additional or supplemental deposit.~~ ~~Except for residential customers,~~ An additional or supplemental deposit may be required if the Customer does not maintain a satisfactory credit criteria or *payment history*. If a change in usage or classification of service has occurred, the customer may be required to pay an additional deposit up to 2/12 of the annual usage. The Customer will receive a message on the bill informing the Customer that if the account is not current by the specified date listed an additional or supplement deposit will be charged to the account the next time the account is billed. T

1. *Satisfactory payment criteria is defined as paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments and having no meter diversion or theft of service.* N

2. *A nonresidential customer does not maintain satisfactory credit criteria when its credit score at any national independent credit rating service falls to a level that is deemed to be vulnerable to nonpayment, including but not limited to: "C" level at Valueline, a "BB+" level at Standard and Poor's or Fitch, "Ba3" at Moody's. If a nonresidential customer is not rated by a national independent credit rating service, its credit may be evaluated by using credit scoring services, public record financial information, or financial scoring and modeling services, and if it is deemed that the customer is vulnerable to nonpayment, a deposit may be required.* N N

E. Recalculation of Customers Deposit

When a deposit is held longer than 18 months, the Customer may request that the deposit be recalculated based on the Customer's actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential Customer or 10 percent for a non-residential Customer, the Company may collect any underpayment and shall refund any overpayment by check or credit to the Customer's bill. No refund will be made if the Customer's bill is delinquent at the time of the recalculation.

5. PAYMENTS,

Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer's service.

A. Equal Payment Plan

Residential Customers have the option of paying a fixed amount each month under the Company's Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customers' estimated annual usage. The payment amount is subject to periodic review and adjustment during the budget year to more accurately reflect actual usage. The normal plan period is 12 months, which may commence in any month.

In the last month of the plan, if the actual usage during the plan period exceeds the amount billed, the Customer will be billed for the balance due. If an overpayment exists, the amount of overpayment will either be refunded to the Customer or credited to the last bill of the period. If a Customer discontinues service with the Company under the Equal Payment Plan, any amounts not yet paid shall become payable immediately.

If a Customer fails to pay bills as rendered under the Equal Payment Plan, the Company reserves the right to revoke the plan, restore the Customer to regular billing, require immediate payment of any deficiency, and require a cash deposit or other guaranty to secure payment of bills.

(Cont'd on Sheet No. 2-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

B. Average Monthly Payment Plan (Amp)

The Average Monthly Payment Plan (AMP Plan) is available to the following applicable tariffs; R.S.; R.S.-L.M-T.O.D.; ~~Experimental~~ R.S.-T.O.D 2.; S.G.S., and S.G.S.-T.O.D. When mutually agreeable the AMP Plan may be offered by the Company to Customers serviced under other tariffs. T

The AMP Plan is designed to allow the Customer to pay an average amount each month based upon the actual billed amounts during the past twelve (12) months. The average payment amount is based upon the current month's total bill plus the eleven (11) preceding months. That result is divided by the total billing days associated with the billings to determine a per day average. The daily average amount is multiplied by thirty (30) to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average. Again the daily average amount is multiplied by thirty (30) to find the new average payment amount. The average monthly payment amount is calculated each and every month in this manner.

The difference between the actual billings and the AMP Plan billings will be carried in a deferred balance. Both the debit and credit differences will accumulate in the deferred balance for the duration of the AMP Plan year, which is twelve consecutive billings months. At the end of the AMP Plan year (anniversary month), the current month's billing plus the eleven (11) preceding month's billing is summed and divided by the total billing days associated with the billings to determine a per day average. That result is multiplied by thirty (30) to calculate the AMP Plan's monthly payment amount. In addition, the net accumulated deferred balance is divided by 12. This result is added or subtracted to the calculated average payment amount starting with the next billing of the new AMP plan year and will be used in the average payment amount calculation for the remaining AMP plan year. Settlement occurs only when participation in the AMP Plan is terminated. This happens if any account is final billed, if the customer requests termination, or at the Company's discretion when the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the billing now due.

In such instances where sufficient billing history is not available, an AMP Plan may be established by using the actual billing history available throughout the first AMP Plan year.

C. All Payments.

All bills are payable at the business offices or authorized collection agencies of the Company within the time limits specified in the tariff. Failure to receive a bill will not entitle a Customer to any discount or to the remission of any charges for non-payment within the time specified. The word "month" as used herein and in the tariffs is hereby defined to be the elapsed time between 2 successive meter readings approximately 30 days apart.

In the event of the stoppage of or the failure of any meter to register the full amount of energy consumed, the Customer will be billed for the period based on an estimated consumption of energy in a similar period of like use.

The tariffs of the Company are met if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. To discourage delinquency and encourage prompt payment within the specified time limit, certain tariffs contain a delayed payment charge, which may be added in accordance with the tariff under which service is provided. Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding 6 months.

6. **UNDERGROUND SERVICE.**

When a real estate developer desires an underground distribution system within the property which he is developing or when a Customer desires an underground service, the real estate developer or the Customer, as the case may be, shall pay the Company the difference between the anticipated cost of the underground facilities so requested and the cost of the overhead facilities which would ordinarily be installed in accordance with 807 KAR 5:041, Section 21, and the Company's underground service plan as filed with the Public Service Commission. Upon receipt of payment, the Company will install the underground facilities and will own, operate and maintain the same.

(Cont'd on Sheet No. 2-5)

DATE OF ISSUE: December 23, 2014
DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III
TITLE: Director Regulatory Services
By Authority Of Order By The Public Service Commission
In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-5
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-5

TERMS AND CONDITIONS OF SERVICE (Cont'd)

7. **COMPANY'S LIABILITY**

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an event of Force Majeure. Force Majeure consists of an event or circumstance which prevents Company from providing service, which event or circumstance was not anticipated, which is not in the reasonable control of, or the result of negligence of, the Company, and which, by the exercise of due diligence, Company is unable to overcome or avoid or causes to be avoided. Force Majeure events includes act of God, the public enemy, accidents, labor disputes, orders or acts of civil or military authority, breakdowns or injury to the machinery, transmission lines, distribution lines or other facilities of the Company, or extraordinary repairs.

Unless otherwise provided in a contract between the Company and Customer, the point at which service is delivered by Company to Customer, to be known as "delivery point," shall be the point at which the Customer's facilities are connected to the Company's facilities. The metering device is the property of the Company. The meter base, connection, grounds and all associated internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the Customer's use of their equipment or occasioned by the energy furnished by the Company beyond the delivery point.

Beginning September 1, 2014 and thereafter, any new installation, upgrade or other modification of an existing meter installation shall be made using only Company supplied or approved meter bases. A list of Company-approved meter bases and specifications can be found on the Company's website at: www.kentuckypower.com.

The Customer shall provide and maintain suitable protective devices on their equipment to prevent any loss, injury or damage that might result from single phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury or damage resulting from a single phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices. The Company shall not be liable for any damages, whether direct, incidental or consequential, including, without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations, or irregularity in the supply of energy.

The Company is not responsible for loss or damage caused by the disconnection or reconnection of its facilities. The Company is not responsible for loss or damages caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus, which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

8. **CUSTOMER'S LIABILITY.**

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the Customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the Customer.

Customers will be responsible for tampering with, interfering with, or breaking of seals of meters, or other equipment of the Company installed on the Customer's premises. The Customer hereby agrees that no one except the employees of the Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus, which shall be the property of the Company.

(Cont'd on Sheet 2-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-6
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-6

TERMS AND CONDITIONS OF SERVICE (Cont'd)

8. **CUSTOMER'S LIABILITY (Cont'd)**

The Company shall have the right at all reasonable hours to enter the premises of the Customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause.

9. **EXTENSION OF SERVICE.**

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customers other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

For service to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide such new facilities at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to serve the load and the estimated revenue for one year; (c) if the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed.

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer's requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to serve shall be the sum of the following components:

1. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer's requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.

2. The annual energy costs based on the latest available production costs related to the Customer's estimated annual energy use requirements.

3. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

(Cont'd on Sheet No. 2-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-7
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-7

TERMS AND CONDITIONS OF SERVICE (Cont'd)

9. **EXTENSION OF SERVICE (Cont'd)**

If the estimated revenue for one year is greater than the cost to serve as described herein, the Company may provide any new local facilities required at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in revenue.

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the company may require the Customer to execute an Advance and Refund Agreement where the Company reasonably questions the longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customers shall pay the company the estimated total installed cost of the required new facilities which advance could be refunded over a five year period under certain circumstances. Over the five year period the Customer' electric bill would be credited each month up to the amount of 1/60th of the total amount advanced.

10. **EXTENSION OF SERVICE TO MOBILE HOME.**

The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

11. **LOCATION AND MAINTENANCE OF COMPANY'S EQUIPMENT.**

The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

12. **BILLING FORM.**

Pursuant to 807 KAR 5:006, Section 7 (3) copies of the billing forms used by the Company are shown on Sheet Nos. *2-12 thru 2-17.* T

13. **RATE SCHEDULE SELECTION.**

The Company will explain to the Customer, at the beginning of service or upon request the Company's rates available to the Customer. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change their initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedule.

(Cont'd on Sheet No. 2-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-8
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-8

TERMS AND CONDITIONS OF SERVICE (Cont'd)

14. **MONITORING USAGE.**

At least once ~~annually~~ *quarterly* the Company will monitor the usage of each customer according to the following procedure: T

1. The Customer's monthly usage will be compared with the usage of the corresponding period of the previous year.
2. If the monthly usage for the two periods is substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.
3. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the Customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.
4. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, the Company will contact the Customer to determine whether there have been changes that explain the increased or decreased usage.
5. Where the deviation is not otherwise explained, the Company will test the Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.
6. The Company will notify the customers of the investigation, its findings, and any refunds or back billing in accordance with 807 KAR 5:006, Section *11*(4) and (5). T

In addition to the ~~annually~~ *quarterly* monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading, billing processes, or customer inquiry. T

15. **USE OF ENERGY BY CUSTOMER.**

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

Upon the expiration of an electric service contract, if required by the terms of the tariff, the Customer may elect to renew the contract upon the same or another tariff published by the Company available to the Customer and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer.

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric energy must not be used in such a manner as to cause unprovided for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

(Cont'd on Sheet No. 2-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

15. **USE OF ENERGY BY CUSTOMER. (Cont'd)**

No attachment of any kind whatsoever may be made to the Company's lines, poles, cross arms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devices, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load.

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs, which specifically provide for same.

The Customer shall not be permitted to operate generating equipment in parallel with the Company's service except with express written consent of the Company.

Resale of energy will be permitted only with express written consent by the Company.

16. **RESIDENTIAL SERVICE.**

~~Individual~~ *Except as otherwise provided in these tariffs, individual* residences shall be served individually with single-phase service under the applicable residential service tariff. Customer may not take service for 2 or more separate residences through a single point of delivery under any tariff. Exclusions may be allowed pursuant to 807 KAR 5:046 (Prohibition of master metering). T

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional or gainful purposes, which requires three phase service or which requires service to motors in excess of 10 HP each. Under these circumstances, Customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential service tariff and the other uses as enumerated above are served through a separate meter or meters under the applicable general service tariff; or (2) taking the entire service under the applicable general service tariff.

Detached building or buildings, actually appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the Customer's residence wiring through the residence meter and under the applicable residential service tariff.

17. **DENIAL OR DISCONTINUANCE OF SERVICE.**

The Company reserves the right to refuse ~~to~~ *or discontinue service to any* ~~applicant or~~ customer ~~for service or to discontinue~~ T
~~to serve any Customer~~ if the ~~applicant or~~ customer is indebted to the Company for any service theretofore rendered at any T
location; provided however, ~~the applicant or~~ customer shall be notified in writing in accordance with 807 KAR 5:006, T
Section *15*, before disconnection of service.

Any discontinuance of service shall not terminate the contract for electric service between the Company and the applicant or customer nor shall it abrogate any minimum charge, which may be effective.

(Cont'd on Sheet No. 2-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2-10
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 2-10

TERMS AND CONDITIONS OF SERVICE (Cont'd)

18. **EMPLOYEE'S DISCOUNT.**

Regular employees who have been in the Company's employ for 6 months or more may, at the discretion of the Company, receive a reduction in their residence electric bills for the premises occupied by the employee.

19. **SPECIAL CHARGES.**

A. Reconnection and Disconnect Charges
In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 9 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 16 shall be exempt from the reconnect charges.

1. Reconnect for nonpayment during regular hours..........................$ ~~12.94~~ *$ 21.00* I
2 Reconnect at the end of the day (No "Call Out" required)............ $ ~~17.26~~ *$ 30.00* I
3. Reconnect for nonpayment when a "Call Out" is required *prior to 10:00 PM* N
(A "Call Out" is when an employee must be called in to work on an overtime basis to make the reconnect trip. *Reconnection for nonpayment will not be made* N
when a "Call Out" after 10:00 p.m. is required)........................ $ ~~35.95~~ *$ 95.00* I
4. Reconnect for nonpayment when double time is required
(Sunday and Holiday)... $ ~~44.58~~ *$124.00* I
5. Termination or field trip.. $ ~~8.63~~ *$ 13.00* I

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

B. *Meter Reading Check* N

Pursuant to 807 KAR 5:006, Section 9 (3) (d) in cases where a customer requests a meter be reread, and the second reading shows the original reading was correct, the Customer will be charged a fee of $21.00 to cover the handling cost. N

C. Returned Check Charge

In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of ~~$7.00~~ *$ 18.00* to cover the handling costs. I

D. Meter Test Charge

Where test of a meter is made upon written request of the Customer pursuant to 807 KAR 5:006, Section *19*, the Customer will be charged ~~$14.38~~ *$ 48.00* if such test shows that the meter was not more than two percent (2%) fast. T I

(Cont'd on Sheet No. 2-11)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2 –12
CANCELLING P.S.C. KY. NO. 10 __________ SHEET NO. 2 –12

TERMS AND CONDITIONS OF SERVICE (Cont'd)
Residential Bill Form Page 1

KENTUCKY POWER
A unit of American Electric Power

Send Inquires To:
PO BOX 24401
CANTON, OH 44701-4401
R-00-999999999

Account Number
030-999-999-9-9
CY XX
XXXXXXX

$XXX.XX	$__________
Total Amount Due	Amount Enclosed
Due MM/DD, Add $XX.XX After This Date	

KPCo RESIDENTIAL CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Make Check Payable and Send To:
KENTUCKY POWER COMPANY
PO BOX 24410
CANTON OH 44701-4410

99999999900000000000000000999999999999999999900000999999999999999999999999999999999990000000000000

Please tear on dotted line Return top portion with your payment

Service Address:
KPCo RESIDENTIAL CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Rate Tariff: Residential Service -015

Account Number	Total Amount Due	Due Date
030-999-999-9-9	$XXX.XX	MM/DD/YY
Meter Number	**Cycle-Route**	**Bill Date**
999999999	XX-XX	MM/DD/YY

Questions about Bill or Service, Call:
Call: 1-800-572-1113
Pay By Phone: 1-800-611-0964

KPCo Messages

Got a new dog in your yard? Let us know about it. Call the number on your bill so we can note it on your account.

You can now reach our customer service representatives 24 hours a day, 7 days a week. Please help us by having your account number when you call.

Flip the Switch and turn off your paper bill! You will gain the benefit of receiving an email when your bill is ready to be viewed and the security of viewing it safely anytime, anywhere.

Stealing copper is illegal and can have deadly consequences. Reporting copper theft could save a life. If you have any information, please call 1-866-747-5845.

Having a phone number for this address can help us serve you better, especially when storms cause service interruptions.

Previous Charges:			
Total Amount Due At Last Billing	$	XXX.XX	
Payment MM/DD/YY - Thank You		XXX.XX	
Previous Balance Due	$	XXX.XX	
Current KPCo Charges:			
Tariff 015 - Residential Service MM/DD/YY			
Rate Billing	$	XXX.XX	
Fuel Adj @ 0.XXXXXXX Per KWH		XX.XX	
DSM Adj @0.XXXXXX Per KWH		X.XX	
Residential HEAP @ $0.15		0.15	
Kentucky Economic Development Surcharge @ $0.15		0.15	N
Capacity Charge @ 0.XXXXXX Per KWH		X.XX	
Big Sandy 1 Operations Rider @ 0.XXXXX Per KWH		XX.XX	N
Asset Transfer Rider @ X.XXXXXX%		XX.XX	
PJM Rider @ 0.XXXX Per KWH		XX.XX	N
NERC Cybersecurity Rider @ 0.XXXX Per KWH		XX.XX	N
Environmental Adj X.XXXXXX%		XX.XX	
Big Sandy Retirement Rider @ X.XXXXXX%		XX.XX	N
Purchased Power Adjustment @ 0.XXXXXX Per KWH		XX.XX	
Green Pricing XXX Blocks		XX.XX	
School Tax		XX.XX	
Franchise Tax		XX.XX	
State Sales Tax		XX.XX	
Current Electric Charges Due	$	XXX.XX	
Homeserve Warranty Service (855-769-6267)	$	XX.XX	
Total Amount Due	$	XXX.XX	
Due MM/DD, Add $XX.XX After This Date			

(Cont'd on Sheet No. 2-13)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Residential Bill Form _ Page 2

Homeserve USA is optional. Homeserve USA is not the sames as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated service from KPCO.

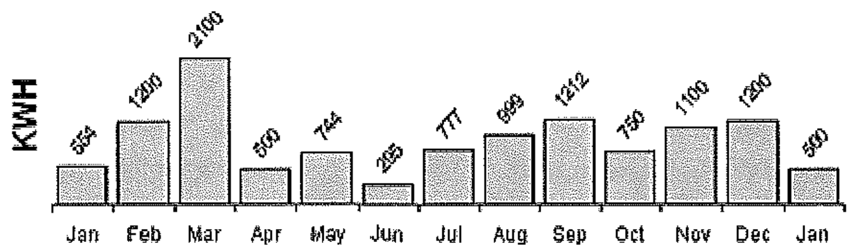
w w w .kyelectricalprotectionplan.com

Visit us at w w w .KentuckyPow er.com
Rates available on request
See other side for Important Information

AEP KENTUCKY POWER®
A unit of American Electric Power

Meter	Service Period		Meter Reading Detail			
Number	From	To	Previous	Code	Current	Code
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier X.XXXX			Metered Usage X,XXX KWH			
Next scheduled read date should be between MM/DD and MM/DD						

13 Month Usage History **Total KWH for Past 12 Months is XX,XXX**



Month	Total KWH	Days	KWH Per Day	Cost Per Day	Average Temperature
Current	XXX	XX	X,XXX	$XXX.XX	66° F
Previous	XXX	XX	X,XXX	$XXX.XX	66° F
One Year Ago	XXX	XX	X,XXX	$XXX.XX	48° F
Your Average Monthly Usage: X,XXX KWH					

(Cont'd on Sheet No. 2-14)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Small Commercial Bill Form Page 1

AEP KENTUCKY POWER
A unit of American Electric Power

Send Inquires To:
PO BOX 24401
CANTON, OH 44701-4401
R-00-999999999

Account Number
030-999-999-9-9
CY XX
XXXXXXX

$XXX.XX	$________
Total Amount Due	Amount Enclosed
Due MM/DD, Add $XX.XX After This Date	

KPCo SMALL GEN SERV CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Make Check Payable and Send To:
KENTUCKY POWER COMPANY
PO BOX 24410
CANTON OH 44701-4410

99999999900000000000000000099999999999999999999000009999999999999999999999999999999999000000000000

Please tear on dotted line -- Return top portion with your payment

Service Address:
KPCo SMALL GEN SERV CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Rate Tariff:Small General Service - 211

Account Number	Total Amount Due	Due Date
030-999-999-9-9	$XXX.XX	MM/DD/YY
Meter Number	**Cycle-Route**	**Bill Date**
999999999	XX-XX	MM/DD/YY

Questions about Bill or Service, Call:
Call: 1-800-572-1113
Pay By Phone: 1-800-611-0964

KPCo Messages
Got a new dog in your yard? Let us know about it. Call the number on your bill so we can note it on your account.

You can now reach our customer service representatives 24 hours a day, 7 days a week. Please help us by having your account number when you call.

Flip the Switch and turn off your paper bill! You will gain the benefit of receiving an email when your bill is ready to be viewed and the security of viewing it safely anytime, anywhere.

Stealing copper is illegal and can have deadly consequences. Reporting copper theft could save a life. If you have any information, please call 1-866-747-5845.

Previous Charges:			
Total Amount Due At Last Billing	$	XXX.XX	
Payment MM/DD/YY - Thank You		XXX.XX	
Previous Balance Due	$	XXX.XX	
Current KPCo Charges:			
Tariff 211 - Small General Service MM/DD/YY			
Rate Billing	$	XXX.XX	
Fuel Adj @ 0.XXXXXXX Per KWH		XX.XX	
DSM Adj @0.XXXXXX Per KWH		X.XX	
Capacity Charge @ 0.XXXXXX Per KWH		X.XX	
Kentucky Economic Development Surcharge @ $0.15		0.15	N
Big Sandy 1 Operations Rider @ 0.XXXXX Per KWH		XX.XX	N
Asset Transfer Rider @ X.XXXXXX%		XX.XX	
PJM Rider @ 0.XXXX Per KWH		XX.XX	N
NERC Cybersecurity Rider @ 0.XXXX Per KWH		XX.XX	N
Environmental Adj X.XXXXXX%		XX.XX	
Big Sandy Retirement Rider @ X.XXXXXX%		XX.XX	N
Purchased Power Adjustment @ 0.XXXXXX Per KWH		XX.XX	
Green Pricing XXX Blocks		XX.XX	
School Tax		XX.XX	
Franchise Tax		XX.XX	
State Sales Tax		XX.XX	
Current Electric Charges Due	$	XXX.XX	
Total Amount Due	$	**XXX.XX**	
Due MM/DD, Add $XX.XX After This Date			

(Cont'd on Sheet No. 2-15)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Small Commercial Bill Form – Page 2

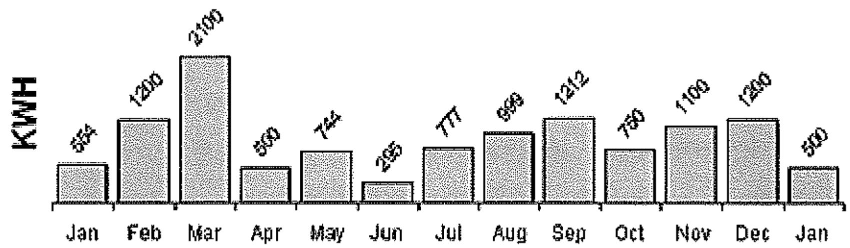
Having a phone number for this address can help us serve you better, especially when storms cause service interruptions.

Visit us at www.KentuckyPower.com
Rates available on request
See other side for Important Information

KENTUCKY POWER
A unit of American Electric Power

Meter	Service Period		Meter Reading Detail			
Number	From	To	Previous	Code	Current	Code
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier X.XXXX			Metered Usage X,XXX KWH			
Next scheduled read date should be between MM/DD and MM/DD						

13 Month Usage History **Total KWH for Past 12 Months is XX,XXX**



Month	Total KWH	Days	KWH Per Day	Cost Per Day	Average Temperature
Current	XXX	XX	X,XXX	$XXX.XX	66° F
Previous	XXX	XX	X,XXX	$XXX.XX	66° F
One Year Ago	XXX	XX	X,XXX	$XXX.XX	48° F
Your Average Monthly Usage: X,XXX KWH					

(Cont'd on Sheet No. 2-16)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 2 –16
CANCELLING P.S.C. KY. NO. 10 __________ SHEET NO. 2 –16

TERMS AND CONDITIONS OF SERVICE (Cont'd)

Large Commercial and Industrial Bill Form – Page 1

AEP KENTUCKY POWER
A unit of American Electric Power

Send Inquires To:
PO BOX 24401
CANTON, OH 44701-4401
R-00-999999999

Account Number
030-999-999-9-9
CY XX
XXXXXXX

$X,XXX.XX	$__________
Total Amount Due	Amount Enclosed
Due MM/DD, Add $XX.XX After This Date	

KPCo LARGE POWER CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Make Check Payable and Send To:
KENTUCKY POWER COMPANY
PO BOX 24410
CANTON OH 44701-4410

999999999000000000000000000999999999999999999900000999999999999999999999999999999999000000000000

Please tear on dotted line Return top portion with your payment

Service Address:
KPCo LARGE POWER CUSTOMER
123 ANY STREET
AEP CITY, KY 99999-9999

Rate Tariff: Large General Service -244 Page 1 of 2

Account Number	Total Amount Due	Due Date
030-999-999-9-9	$X,XXX.XX	MM/DD/YY
Meter Number	Cycle-Route	Bill Date
999999999	XX-XX	MM/DD/YY

Questions about Bill or Service, Call:
Call: 1-800-572-1113
Pay By Phone: 1-800-611-0964

KPCo Messages

Got a new dog in your yard? Let us know about it. Call the number on your bill so w e can note it on your account.

You can now reach our customer service representatives 24 hours a day, 7 days a w eek. Please help us by having your account number w hen you call.

Flip the Sw itch and turn off your paper bill! You w ill gain the benefit of receiving an email w hen your bill is ready to be view ed and the security of view ing it safely anytime, anyw here.

Stealing copper is illegal and can have deadly consequences. Reporting copper theft could save a life. If you have any information, please call 1-866-747-5845.

Previous Charges:			
Total Amount Due At Last Billing	$	X,XXX.XX	
Payment MM/DD/YY - Thank You		X,XXX.XX	
Previous Balance Due	$	X,XXX.XX	
Current KPCo Charges:			
Tariff 244 - Large General Service MM/DD/YY			
Rate Billing	$	X,XXX.XX	
Fuel Adj @ 0.XXXXXXX Per KWH		XXX.XX	
DSM Adj @0.XXXXXX Per KWH		XXX.XX	
Capacity Charge @ 0.XXXXXX Per KWH		XX.XX	
Kentucky Economic Development Surcharge @ $0.15		0.15	N
Big Sandy 1 Operations Rider @ 0.XXXXX Per KWH		XX.XX	N
Asset Transfer Rider @ X.XXXXXX%		XX.XX	
PJM Rider @ 0.XXXX Per KWH		XX.XX	N
NERC Cybersecurity Rider @ 0.XXXX Per KWH		XX.XX	N
Environmental Adj X.XXXXXX%		XX.XX	
Big Sandy Retirement Rider @ X.XXXXXX%		XX.XX	N
Purchased Power Adjustment @ 0.XXXXXX Per KWH		XX.XX	
Green Pricing XXX Blocks		XX.XX	
School Tax		XX.XX	
Franchise Tax		XX.XX	
State Sales Tax		XX.XX	
Current Electric Charges Due	$	X,XXX.XX	
Total Amount Due	$	**X,XXX.XX**	
Due MM/DD, Add $XX.XX After This Date			

(Cont'd on Sheet No. 2-17)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TERMS AND CONDITIONS OF SERVICE (Cont'd)

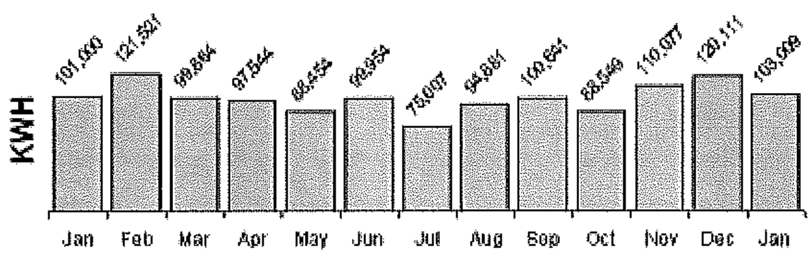
Large Commercial and Industrial Bill Form – Page 2

Send Inquires To:
PO BOX 24401
CANTON, OH 44701-4401
R-00-999999999

Service Address:
KPCo LARGE POWER CUSTOMER
123 ANY STREET
ANY CITY, KY 99999-9999

Meter	Service Period		Meter Reading Detail			
Number	From	To	Previous	Code	Current	Code
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier XXX.XXXX			Metered Usage XXX,XXX KWH			
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier XXX.XXXX			Metered Usage XXX,XXX KW			
999999999	MM/DD	MM/DD	XXXXX	Actual	XXXXX	Actual
Multiplier XXX.XXXX			Metered Usage XXX,XXX KVARH			
Next Scheduled read date should be between MM/DD and MM/DD						

13 Month Usage History Total KWH for Past 12 Months is X,XXX,XXX



Stealing copper is illegal and can have deadly consequences. Reporting copper theft could save a life. If you have any information, please call 1-866-747-5845.

Having a phone number for this address can help us serve you better, especially when storms cause service interruptions.

Meter Number	Cycle-Route	Bill Date
999999999	99-99	MM/DD/YY

Month	Total KWH	Days	KWH Per Day	Cost Per Day	Average Temperature
Current	XXX,XXX	XX	X,XXX	$XXX.XX	66° F
Previous	XXX,XXX	XX	X,XXX	$XXX.XX	68° F
One Year Ago	XXX,XXX	XX	X,XXX	$XXX.XX	49° F
Your Average Monthly Usage: XXX,XXX KWH					

Visit us at www.KentuckyPower.com
Rates available on request
See other side for Important Information

Adjusted Usage MM/YY				
	Power	Power Factor	Comp. Meter	
	Factor	Constant	Multiplier	
Metered Usage	(XX.X)	(XXX.XXXX)		Billing Usage
XXX,XXX				XXX,XXX KWH
XXX,XXX				XXX,XXX KW
XXX,XXX				XXX,XXX KVARH
Contract Capacity = X,XXXX.X		High Prev Demand = X,XXX.X On-Pk		
		High Prev Demand = X,XXX.X Off-Pk		

AEP KENTUCKY POWER
A unit of American Electric Power

Additional Messages

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM

The Company's Capacity and Energy Control Program consists of:

I. Procedures During Abnormal System Frequency

II. Capacity Deficiency Program

III. Energy Emergency Control Program

A copy of the Company's Emergency Operating Plan was filed with the Kentucky Public Service Commission on May 1, ~~2008~~ *2014* in Administrative Case No. ~~353~~ *345* in compliance with the Commission's Order dated ~~January 20, 1995~~ *May 18, 1993.* T

I. PROCEDURES DURING ABNORMAL SYSTEM FREQUENCY

A. INTRODUCTION

Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP program, which is in accordance with ECAR Document 3, is noted below.

B. PROCEDURES AEP/PJM

1. From 59.8 – 60.2 Hz to the extent practicable utilize all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the System during the emergency. For rapid frequency decline, only that capacity on-line and automatically responsive to frequency (spinning reserve), and such items as interconnection assistance and load reductions by automatic means are of assistance in arresting the decline in frequency.

   If the frequency decline is gradual, the Generation/Production Optimization Group, particularly in the deficient area, should invoke non-automatic procedures involving operating and emergency reserves. These efforts should continue until the frequency decline is arrested or until automatic load-shedding devices operate at subnormal frequencies.

2. At 59.75 Hz
   a. Suspend Automatic Generation Control (AGC)
   b. Notify Interruptible Customers to drop load

3. At 59.5 Hz automatically shed 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

4. At 59.4 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

5. At 59.3 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

6. At 59.1 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

7. At 59.0 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

8. At 58.9 Hz automatically shed an additional 5% of System internal load, excluding interruptibles, by relay action. (25 cycle, .42 sec. delay)

(Cont'd on Sheet 3-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

PROCEDURES DURING ABNORMAL SYSTEM FREQUENCY (cont'd)

9. At 58.2 Hz automatically trip the D.C. Cook Nuclear Units 1 and 2.

10. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

If at any time in the above procedure the decline in area frequency is arrested below 59.0 Hz, that part of the System in the low frequency area should shed an additional 10% of its initial load. If, after five minutes, this action has not returned the area frequency to 59.0 Hz or above, that part of the System shall shed an additional 10% of its remaining load and continue to repeat in five-minute intervals until 59.0 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units.

II. CAPACITY DEFICIENCY PROGRAM

A. PURPOSE

To provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power (AEP)East/PJM Eastern System in the event of a capacity deficiency.

B. CRITERIA

The goals of AEP areis to safely and reliably operate the interconnected network in order to avoid widespread system outages as a consequence of a major disturbance. Precautionary procedures including maintaining Daily Operating Reserves, as specified in ECAR document 2, and PJM Manual M13, will assist in avoiding serious emergency conditions such as system separation and operation at abnormal frequency. However, adequate Daily Operating Reserves cannot always be maintained, so the use of additional emergency measures may be required. A Capacity Deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements.

C. AEP EAST/PJM PROCEDURES
(note: the following section contains excerpts from PJM Manual – M13)

OVERVIEW

PJM is responsible for determining and declaring that an Emergency is expected to exist, exists, or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM Members as necessary to manage, allocate, or alleviate an emergency.

- ~~*PJM RTO*~~ PJM RTO Reserve Deficiencies — If PJM determines that PJM-scheduled resources available for an Operating Day in combination with Capacity Resources operating on a self-scheduled basis are not sufficient to maintain appropriate reserve levels for the PJM RTO, PJM performs the following actions: T
- Recalls energy from Capacity Resources that otherwise deliver to loads outside the Control Area and dispatches that energy to serve load in the Control Area.
- Purchases capacity or energy from resources outside the Control Area. PJM uses its best efforts to purchase capacity or energy at the lowest prices available at the time such capacity or energy is needed. The price of any such capacity or energy is not considered in determining Locational Marginal Prices in the PJM Energy Market. The cost of capacity or energy is allocated among the Market Buyers as described in the PJM Manual for Operating Agreement Accounting (M-28)

The AEP System Control Center will be referred to as SCC and the AEP Production Optimization Group will be referred to as POG.

(Cont'd on Sheet No. 3-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP EAST/PJM PROCEDURES (cont'd)

CAPACITY SHORTAGES

PJM is responsible for monitoring the operation of the PJM RTO, for declaring the existence of an Emergency, and for directing the operations of the PJM Member as necessary to manage, alleviate, or end an Emergency. PJM also is responsible for transferring energy on the PJM Members behalf to meet an Emergency. PJM is also responsible for agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an Emergency.
Exhibit 1 illustrates that there are three general levels of emergency actions for capacity shortages:

- alerts
- warnings
- actions

ALERTS

The intent of the alerts is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO. All alerts and cancellation thereof are broadcast on the "ALL-CALL" system and posted to selected PJM web sites to assure that all members receive the same information.
Alerts are issued in advance of a scheduled load period to allow sufficient time for members to prepare for anticipated initial capacity shortages.

Maximum Emergency Generation Alert
The purpose of the Maximum Emergency Generation Alert is to provide an early alert that system conditions may require the use of the PJM emergency procedures. It is implemented when Maximum Emergency Generation is called into the operating capacity.

Primary Reserve Alert
The purpose of the Primary Reserve Alert is to alert members of the anticipated shortage of operating reserve capacity for a future critical period. It is implemented when estimated operating reserve capacity is less than the forecast primary reserve requirement.

Voltage Reduction Alert
The purpose of the Voltage Reduction Alert is to alert members that a voltage reduction may be required during a future critical period. It is implemented when the estimated operating reserve capacity is less than the forecast spinning reserve requirement.

Voluntary Customer Load Curtailment Alert
The purpose of the Voluntary Customer Load Curtailment Alert is to alert members of the probable future need to implement a voluntary customer load curtailment. It is implemented whenever the estimated operating reserve capacity indicates a probable future need for voluntary customer load curtailment.

Warnings

Warnings are issued during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO. All warnings and cancellations are broadcasted on the "ALL-CALL" system and posted to selected PJM web sites to assure that all members receive the same information.

Primary Reserve Warning
The purpose of the Primary Reserve Warning is to warn members that the available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve capacity is less than the primary reserve requirement, but greater than the spinning reserve requirement, after all available secondary reserve capacity (except restricted maximum emergency capacity) is brought to a primary reserve status and emergency operating capacity is scheduled from adjacent systems.

(Cont'd on Sheet 3-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

AEP EAST/PJM PROCEDURES (cont'd)

Voltage Reduction Warning & Reduction of Non-Critical Plant Load
The purpose of the Voltage Reduction Warning & Reduction of Non-Critical Plant Load is to warn members that the available spinning reserve is less than the Spinning Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required. It is implemented when the available spinning reserve capacity is less than the spinning reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a spinning reserve status and emergency operating capacity is scheduled from adjacent systems.

Manual Load Dump Warning
The purpose of the Manual Load Dump Warning is to warn members of the increasingly critical condition of present operations that may require manually dumping load. It is issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve. The amount of load and the location of areas(s) are specified.

Actions

The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- Loading generation that is restricted for reasons other than cost
- Recalling non-capacity backed off-system sales
- Purchasing emergency energy from participants / surrounding pools
- Load relief measures

The procedures to be used under these circumstances are described in the general order in which they are applied. Due to system conditions and the time required to obtain results, PJM dispatcher may find it necessary to vary the order of application to achieve the best overall system reliability. Issuance and cancellation of emergency procedures are broadcast over the "ALL-CALL" and posted to selected PJM web sites. Only affected systems take action. PJM dispatcher broadcasts the current and projected PJM RTO status periodically using the "ALL-CALL" during the extent of the implementation of the emergency procedures.

Maximum Emergency Generation
The purpose of the Maximum Emergency Generation is to increase the PJM RTO generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the highest incremental cost level.

Load Management Curtailments (ALM)

Steps 1 and 2 (PJM Control)
The purpose of the Load Management Curtailments, Steps 1 and 2, is to provide additional load relief by using PJM controllable load management programs. Steps 1 and 2 are differentiated only by the expected time to implement. Load relief is required after initiating Maximum Emergency Generation.

Step 1: Short Time Frame to Implement (1 Hour or Less)

- PJM dispatcher requests members to implement Load Management Curtailment, Step 1.

Step 2: Long Time Frame To Implement (Greater Than 1 Hour)

- PJM dispatcher requests members to implement Load Management Curtailment, Step 2.

Steps 3 and 4 (SCC Control)
The purpose of the Local Control Center Programs of Load Management Curtailments, Steps 3 and 4, is to provide additional load relief by requesting use of Local Control Center load management programs.

(Cont'd on Sheet No. 3-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Actions (cont'd)

Load Reduction Program
The purpose of the Load Reduction Action is to request end-use customers to reduce load during emergency conditions.

Voltage Reduction
The purpose of Voltage Reduction during capacity deficient conditions is to reduce load to provide a sufficient amount of reserve to maintain tie flow schedules and preserve limited energy sources. A curtailment of non-essential building load is implemented prior to or at this same time as a Voltage Reduction Action. It is implemented when load relief is still needed to maintain tie schedules.

Note: Voltage reductions can also be implemented to increase transmission system voltage.

Note: Curtailment of non-essential building load may be implemented prior to, but not later than, the same time as a voltage reduction.

Curtailment of Non-Essential Building Load
The purpose of the Curtailment of Non-Essential Building Load is to provide additional load relief, to be expedited prior to, but no later than the same time as a voltage reduction.

Voluntary Customer Load Curtailment
The purpose of the Voluntary Customer Load Curtailment (VCLC) is to provide further load relief. It is implemented when the estimated peak load minus the relief expected from curtailment of non-essential building load and a 2.5% - 5% voltage reduction is greater than operating capacity.

PJM/SCC – Public Appeal to conserve electricity usage

Manual Load Dump
The purpose of the Manual Load Dump is to provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions. It is implemented when the PJM RTO cannot provide adequate capacity to meet the PJM RTO's load or critically overloaded transmission lines or equipment cannot be relieved in any other way and/or low frequency operation occurs in the PJM RTO, parts of the PJM RTO, or PJM RTO and adjacent Control Areas that may be separated as an island.

Addendum to Manual Load Dump Procedures

AEP understands that PJM intends to implement these curtailment protocols consistent with the agreements that PJM entered into in Kentucky and Virginia, in Stipulations approved by the Kentucky Public Service Commission and Virginia State Corporation Commission (with modifications) in Case No. 2002-00475 and Case No. PUE-2000-00550, respectively.

Capacity Deficiency Summary

A summary of the emergency alerts, warning and actions, together with the typical sequence and the method of communication, are presented in the following Table III-2 on Tariff Sheet No. 3-6.

(Cont'd on Sheet No. 3-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

		Communications	Description	
Alert	Maximum Emergency Generation	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC/POG review scheduled or actual maintenance affecting capacity or critical transmission to determine if it can be deferred or cancelled	**EEA 1**
	Primary Reserve	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	(Same as above)	
	Voltage Reduction	PJM-SCC via All-Call SCC-TDC	SCC/TDC to identify stations for Voltage Reduction	
	Voluntary Customer Load Curtailment	PJM-POG via All-Call PJM-SCC via All-Call	Not Applicable	
Warning	Primary Reserve	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC/POG ensure that all deferrable maintenance or testing affecting capacity or critical transmission is halted.	
	Voltage Reduction & Reduction of Non-Critical Plant Load	PJM-POG via All-Call PJM-SCC via All-Call SCC-TDC	SCC to inform TDC to man Voltage Reduction Stations & prepare for Voltage Reduction	POG to reduce plant load. (See Table III-4)
	Manual Load Dump	PJM-SCC via All-Call SCC– POG-Environmental Services SCC-TDC-DDC	Lifting of Environmental Restrictions (See Table III-5)	Manual & Automatic Load Shedding
		Make preparations for a Public Appeal if one becomes necessary.	Obtain permission to exceed opacity limits Obtain permission to exceed heat input limits Obtain permission to exceed river temperature limits	SCC/TDC will review local computer procedures and man manual load shedding stations
Action	Maximum Emergency Generation	PJM-POG via All-Call PJM-SCC via All-Call	Supplemental Oil & Gas Firing; Operate Generator Peakers; Emergency Hydro; Extra Load Capability	See Table III-3
	Load Management Curtailment (ALM)	PJM-SCC via All-Call SCC - POG	Step 3 – 1267 Mws – 1 hr, 249 Mws – 2 hr	**EEA 2** **(DOE Report)**
	Load Reduction Program	PJM-SCC via All-Call	Not Applicable	
	Voltage Reduction	PJM-SCC via All-Call SCC –TDC & SCC - POG	Initiate Voltage Reduction - AEP/PJM – 64 Mws	
	Curtailment of Non-Essential Building Load	PJM-POG via All-Call PJM-SCC via All-Call SCC- Building Services	Initiate curtailment of AEP building load – 4.4 Mws	Issued approx. same time as Voltage Reduction
	Voluntary Customer Load Curtailment	PJM-POG via All-Call PJM-SCC via All-Call	Not Applicable	**EEA 3** **(DOE Report)**
	Public Appeal (may be issued at any stage of the Action items)	SCC – Corporate Communications	Radio and TV alert to general public	2% of AEP Internal Load
		SCC – Customer Services SCC - POG	Call to Industrial and Commercial Customers	1276 Mws - 1 hr + 320 Mws - 2 hr
		SCC - TDC	Municipal and REMC Customers	7% of Cust. Load
	Manual Load Dump	PJM-SCC via All-Call SCC-POG-Environmental Services SCC-TDC-DDC	PJM Allocation based on deficient zones	
			Lift Environmental Restrictions on units	(regains curtailed generation)
			Selected distribution customers (manual load curtailment)	Execute MLD

(Cont'd on Sheet No.3-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Energy Emergency Alert Levels (reference NERC Appendix 5C)

1. Alert 1 - All available resources in use.

   Circumstances:
   - Control Area, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 - Load management procedures in effect.

   Circumstances:
   - Control Area, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
   - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
     - Voltage reduction
     - Emergency Curtailable Service
     - Public appeals to reduce demand
     - Interruption of non-firm end use loads in accordance with applicable contracts, for emergency, not economic reasons
     - Demand-side management
     - Utility load conservation measures
   - During Alert 2, The Reliability Coordinators, Control Areas, and Energy Deficient Entities and AEP have the following responsibilities:

     2.1 Notifying other Control Areas and Market Participants.

     2.2 Declaration Period. The Energy Deficient Entity shall update the Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated.

     2.3 Share information on resource availability.

     2.4 Evaluating and mitigating transmission limitations.
     2.4.1 Notification of ATC adjustments.
     2.4.2 Availability of generation redispatch options.
     2.4.3 Evaluating impact of current Transmission Loading Relief events.
     2.4.4 Initiating inquiries on reevaluating Operating Security Limits.

     2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

     2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of available resources. This includes but is not limited to:

     2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

(Cont'd on Sheet 3-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM (Cont'd)

Energy Emergency Alert Levels (reference NERC Appendix 5C) (Cont'd)

2.6.2 Purchases made regardless of cost. All firm and non=firm purchases have been made regardless of cost.

2.6.2 Non-firm sales recalled and contractually interruptible loads and DSM curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and Demand-side Management activated within provisions of the agreements.

2.6.3 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity AEP is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 - Firm load interruption imminent or in progress.

Circumstances:

- Control Area or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2.

3.2 Declaration Period. The Energy Deficient Entity shall update the Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated.

3.3 Use of Transmission short-time limits.

3.4 Reevaluating and revising Operating Security Limits.
3.4.1 AEP Energy Deficient Entity obligations. The deficient Control Area or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.
3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use his best efforts to ensure that revising Operating Security Limits would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency Operating Security Limits, the Control Area Coordinator Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the Alert.
3.5.1 Notification of other parties. Notifications will be made via Oasis and the RCIS.

3.6 Reporting. Any time an Alert 3 is declared, the Control Area Coordinator Energy Deficient Entity shall complete the report listed in NERC Appendix 9B, Section C and submit this report to its respective Reliability Coordinator within two business days of downgrading or termination of the Alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC web site. The Reliability Coordinator shall present this report to the appropriate NERC Sub-committee Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of his Reliability Coordinator that the EEA be terminated.

4.1 Notification.

(Cont'd on Sheet No. 3-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM

III. ENERGY EMERGENCY CONTROL PROGRAM

A. INTRODUCTION

The purpose of this plan is to provide for the reduction of the consumption of electric energy on the American Electric Power Company System in the event of a severe coal fuel shortage, such as might result from a general strike, or severe weather.

B. PROCEDURES

In the event of a potential severe coal shortage, such as one resulting from a general coal strike, the following steps will be implemented. These steps will be carried out to the extent permitted by contractual commitments or by order of the regulatory authorities having jurisdiction.

A. To be initiated when system fuel supplies are decreased to 70% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Optimize the use of non-coal-fired generation to the extent possible.

2. For individual plants significantly under 750% of normal minimum target days' supply, review the prudence of modifying economic dispatching procedures to conserve coal.

3. If necessary discontinue all economy sales to neighboring utilities.

4. Curtail the use of energy in company offices, plants, etc., over and above the reductions already achieved by current in-house conservation measures.

B. To be initiated when system fuel supplies are decreased to 60% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Substitute the use of oil for coal, as permitted by plant design, oil storage facilities, and oil availability.

2. Discontinue all economy and short-term sales to neighboring utilities.

3. Limit emergency deliveries to neighboring utilities to situations where regular customers of such utilities would otherwise be dropped or where the receiving utility agrees to return like quantities of energy within 14 days.

4. Curtail electric energy consumption by customers on Interruptible contracts to a maximum of 132 hours of use at contract demand per week.

5. Purchase energy from neighboring systems to the extent practicable.

6. Purchase energy from industrial customers with generation facilities to the extent practicable.

7. Through the use of news media and direct consumer contact, appeal to all customers (retail as well as wholesale) to reduce their nonessential use of electric energy as much as possible, in any case by at least 25%.

8. Reduce voltage around the clock to the extent feasible.

9. The Company will advise customers of the nature of the mandatory program to be introduced in C below, through direct contact and mass media, and establish an effective means of answering specific customer inquiries concerning the impact of the mandatory program on electricity availability.

(Cont'd on Sheet 3-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

CAPACITY AND ENERGY CONTROL PROGRAM(Cont'd)

III. **ENERGY EMERGENCY CONTROL PROGRAM(Cont'd)**

B. PROCEDURES (Cont'd)

C. To be initiated -- in the order indicated below -- when system fuel supplies are decreased to 50% of normal target days' operation of coal-fired generation plants and a continued downward trend in coal stocks is anticipated:

1. Discontinue emergency deliveries to neighboring utilities unless the receiving utility agrees to return like quantities of energy within seven days.

2. Request all customers, retail as well as wholesale, to reduce their nonessential use of electric energy by 100%.

3 Request, through mass communication media, curtailment by all other customers a minimum of 15% of their electric use. These uses include lighting, air-conditioning, heating, manufacturing processes, cooking, refrigeration, clothes washing and drying and any other loads that can be curtailed.

4. All customers will be advised of the mandatory program specified below in D.

D. To be initiated when system fuel supplies are decreased to 40% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

1. Implement procedures for curtailment of service to all customers to a minimum service level that is not greater than that required for protection of human life and safety, protection of physical plant facilities and employees' security. This step asks for curtailment of the maximum load possible without endangering life, safety and physical facilities.

2. All customers will be advised of the mandatory program specified below in E.

E. To be initiated when system fuel supplies are decreased to 30% of normal target days' operation of coal-fired generation and a continued downward trend in coal stocks is anticipated:

Implement procedures for interruption of selected distribution circuits on a rotational basis, while minimizing – to the extent practicable – interruption to facilities that are essential to the public health and safety. (See Section II, Step 14.)

F. The Energy Emergency Control Program will be terminated when:

1. The AEP System's remaining days of operation of coal-fired generation is at least 40% of normal target days' operation, and
2. Coal deliveries have been resumed, and
3. There is reasonable assurance that the AEP System's coal stocks are being restored to adequate levels.

With regard to mandatory curtailments identified in Items C, D, and E above, the Company proposes to monitor compliance after the fact. A customer exceeding his electric allotment would be warned to curtail his usage or face, upon continuing noncompliance and upon one day's actual written notice, disconnection of electric service for the duration of the energy emergency.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

STANDARD NOMINAL VOLTAGES

The voltage available to any individual customer shall depend upon the voltage of the Company's lines serving the area in which customer is provided service.

Electric service provided under the Company's rate schedules will be 60 hertz alternating current delivered from various load centers at nominal voltages and phases as available in a given location as follows:

SECONDARY DISTRIBUTION VOLTAGES.

Residential Service

Single phase 120/240 volts three wire or 120/208 volts three wire on network system.

General Service - All Except Residential

Single-phase 120/240 volts three wire or 120/208 volts three wire on network system. Three-phase 120/208 volts four wire on network system, 120/240 volts four wire, 240 volts three wire, 480 volts three wire and 277/480 volts four wire.

PRIMARY DISTRIBUTION VOLTAGES.

The Company's primary distribution voltage levels at load centers are 2,400; 4,160Y; 7,200; 12,470Y, 19,900 and 34,500Y.

SUBTRANSMISSION LINE VOLTAGES.

The Company's sub transmission voltage levels are 19,900; 34,500; 46,000; and 69,000.

TRANSMISSION LINE VOLTAGES.

The Company's transmission voltage levels are 138,000; 161,000; 345,000; and 765,000.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF F.A.C.
(Fuel Adjustment Clause)

APPLICABLE.

To Tariffs R.S.,Experimental R.S.T.O.D. 2, R.S.-L.M.-T.O.D. R.S.-T.O.D., S.G.S., ~~Experimental~~ S.G.S.-T.O.D.,M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S. T.O.D., ~~Q.P., C.I.P.-T.O.D.~~ *I.G.S.*, C.S.-I.R.P., M.W., O.L., and S.L. T

RATE.

1. The fuel clause shall provide for periodic adjustment per kwh of sales equal to the difference between the fuel costs per kwh of sales in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F\,(m)}{S\,(m)} - \frac{F\,(b)}{S\,(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below:

2. F(b)/S(b) shall be so determined that on the effective date of the Commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero (0).

3. Fuel costs (F) shall be the most recent actual monthly cost of:

   a. Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of the fuel related substitute generation, plus

   b. The actual identifiable fossil and nuclear fuel costs [if not known--the month used to calculate fuel (F), shall be deemed to be the same as the actual unit cost of the Company generation in the month said calculations are made. When actual costs become known, the difference, if any, between fuel costs (F) as calculated using such actual unit costs and the fuel costs (F) used in that month shall be accounted for in the current month's calculation of fuel costs (F)] associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

   c. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

   d. The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

   e. All fuel costs shall be based on weighted average inventory costing.

4. Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacturer, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel costs of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel costs (F) in subsection (3)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(Cont'd on Sheet No. 5-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF F.A.C. (Cont'd)
(Fuel Adjustment Clause)

5. Sales (S) shall be all kwh's sold, excluding intersystem sales. Where, for any reason billed system sales cannot be coordinated with the fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) intersystem sales referred to in subsection (3)(d) above, less (vi) total system loss. Utility used energy shall not be excluded in the determination of sales (S).

6. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts or Public Utilities and Licensees.

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options or similar such documents, and all amendments and modifications thereof related to the procurement of fuel supply and purchased power. Incorporation by reference is permissible. Any changes in the documents, including price escalations, or any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. Where fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges, which are unreasonable, shall be disallowed and may result in the suspension of the fuel adjustment clause. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by this regulation.

8. Any tariff filing which contains a fuel clause shall conform that clause with this regulation within three (3) months of the effective date of this regulation. The tariff filing shall contain a description of the fuel clause with detailed cost support.

9 The monthly fuel adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

10. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884.

11. At six (6) month intervals, the Commission will conduct public hearings on a utility's past fuel adjustments. The Commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustment it finds unjustified due to improper calculation or application of the charges or improper fuel procurement practice.

12. Every two (2) years following the initial effective date of each utility fuel clause, the Commission in a public hearing will review and evaluate past operations of the clause, disallow improper expenses, and to the extent appropriate, reestablish the fuel clause charge in accordance with Subsection 2.

13. Resulting cost per kilowatt-hour in June 2008 to be used as the base cost in Standard Fuel Adjustment Clause is :

Fuel -	June 2008 =	$16,138,627 = $ 0.02840/kwh
Sales	June 2008	568,162,000

This, as used in the Fuel Adjustment Clause, is 2.840¢ per kilowatt-hour.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.
(Residential Service)

AVAILABILITY OF SERVICE.

Available for full domestic electric service through 1 (one) meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

RATE. (Tariff Codes 015, 017, 022)

Service Charge........	$ ~~8.00~~ *$16.00* per month	I
Energy Charge:	~~8.590¢~~ *9.035¢* per KWH	I

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased *or decreased* by ~~an Experimental~~ *a* Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule. T T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule N

(Cont'd on Sheet No. 6-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S. (Cont'd)
(Residential Service)

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

VOLUNTEER FIRE DEPARTMENTS *(Tariff Code 024)* N

Volunteer Fire Departments may qualify pursuant to KRS 278.172 for this tariff but will be required to provide a completed Form 990 and update it annually. N

(Cont'd on Sheet No. 6-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.(Cont'd)
(Residential Service)

STORAGE WATER HEATING PROVISION.

This provision is withdrawn except for the present installations of current customers receiving service hereunder at premises served prior to April 1, 1997.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

Tariff Code

012 (a) For Minimum Capacity of 80 gallons, the last 300 KWH of use in any month shall be billed at 4.940¢ per KWH.

013 (b) For Minimum Capacity of 100 gallons, the last 400 KWH of use in any month shall be billed at 4.940¢ per KWH.

014 (c) For Minimum Capacity of 120 gallons or greater, the last 500 KWH of use in any month shall be billed at 4.940¢ per KWH.

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00PM to 7:00AM for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, the Fuel Adjustment Clause, the System Sales Clause, the Demand-Side Management Clause, the Asset Transfer Rider, *Big Sandy Retirement Rider, Big Sandy 1 Operation Rider*, the Purchase T
Power Adjustment, the Environmental Surcharge, the Capacity Charge, *the P.J.M. Rider, the Kentucky Economic* T
Development Rider, the Residential HEAP Charge, *NERC Compliance and Cybersecurity Rider* factors as stated in the T
above monthly rate.

(Cont'd. on Sheet No. 6-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.
(Residential Service)

LOAD MANAGEMENT WATER-HEATING PROVISION. (Tariff Code 011)

For residential customers who install a ~~Company approved~~ load management water-heating system which consumes electrical energy ~~primarily~~ during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at ~~4.940¢~~ *5.216¢* per KWH. T I

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

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

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

This provision is subject to the Service Charge, the Fuel Adjustment Clause, the System Sales Clause, the Demand-Side Management Clause, the Asset Transfer Rider, the Purchase Power Adjustment, the Environmental Surcharge, the Capacity Charge and the Residential HEAP Charge factors as stated in the above monthly rate.

SPECIAL TERMS AND CONDITIONS.

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

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

~~This tariff is available for single-phase service only. Where 3-phase power service is required and/or where motors or heating equipment are used for commercial or industrial purposes, another applicable tariff will apply to such service.~~ D

The Company shall have the option of reading meters monthly or bimonthly and rendering bills accordingly. When bills are rendered bimonthly, the minimum charge and the quantity of KWH in each block of the rates shall be multiplied by two.

Pursuant to 807 KAR 5:041, Section 11, paragraph (1), of Public Service Commission Regulations, the Company will make an extension of 1,000 feet or less to its existing distribution line without charge for a prospective permanent residential customer served under this R.S. Tariff. *Pursuant to 807 KAR 5:041 Section 12 extensions of up to 150 feet for a mobile home are provided without charge.* N

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement.

(Cont'd on Sheet No. 6-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-L.M.-T.O.D.
(Residential Service Load Management Time-of-Day)

AVAILABILITY OF SERVICE.

Available to customers eligible for Tariff R.S. (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this tariff shall be metered through ~~one single-phase~~ *a* multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods. T

RATE. (Tariff Codes 028, 030, 032, 034)

Service Charge	$ ~~10.55~~ *18.70* per month	I
Energy Charge:		
All KWH used during on-peak billing period	~~13.227¢~~ *13.879¢* per KWH	I
All KWH used during off-peak billing period	~~4.940¢~~ *5.216¢* per KWH	I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

CONSERVATION AND LOAD MANAGEMENT CREDIT.

For the combination of an approved electric thermal storage space heating system and water heater, both of which are designed to consume electrical energy only between the hours of 9:00P.M. and 7:00A.M. for all days of the week, each residence will be credited 0.745¢ per KWH for all energy used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule. T

(Cont'd. on Sheet 6-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-L.M.-T.O.D. (Cont'd)
(Residential Service Load Management Time-of-Day)

ASSET TRANSFER RIDER

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet Nos. 38-1 thru 38-2 of this Tariff Schedule. N

BIG SANDY 1 OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet No. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1thru 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 and 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider factor per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 thru 24-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 6-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-L.M.-T.O.D. (Cont'd)
(Residential Service Load Management Time-of-Day)

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers' bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 thru 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

SEPARATE METERING PROVISION.

Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be ~~$3.00~~ *$3.85* per month. I

SPECIAL TERMS AND CONDITIONS.

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

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

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

(Cont'd on Sheet 6-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

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

AVAILABILITY OF SERVICE.

Available for residential electric service through *a* ~~one single-phase~~ multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits. Availability is limited to the first 1,000 customers applying for service under this tariff. T

RATE. (Tariff Code 036)

Service Charge	$ ~~10.55~~ *$18.70* per month	I
Energy Charge:		
All KWH used during on-peak billing period	~~13.227¢~~ *13.879¢* per KWH	I
All KWH used during off-peak billing period	~~4.940 ¢~~ *5.216¢* per KWH	I

For the purpose of this tariff, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00P.M. to 7:00A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bill computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment actor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet Nos. 38-1 thru 38-2 of this Tariff Schedule. N

(Cont'd on Sheet No. 6-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

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

BIG SANDY 1 OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 thru 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers' bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 6-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S. - T.O.D. (Cont'd)
(Residential Service Time-of-Day)

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

SPECIAL TERMS AND CONDITIONS.

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

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

(Cont'd on Sheet No. 6-11)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S. – T.O.D.2
(Experimental Residential Service Time-of-Day 2)

AVAILABILITY OF SERVICE.

Available on a voluntary, experimental basis to individual residential customers for residential electric service through a ~~one single-phase~~, multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff. T

RATE. (Tariff Code 027)

Service Charge	$ ~~11.45~~ *18.70* per month	I
Energy Charge:		
All KWH used during Summer on-peak billing period	~~11.406¢~~ *10.885¢* per KWH	R
All KWH used during Winter on-peak billing period	~~13.829¢~~ *12.132¢* per KWH	R
All KWH used during off-peak billing period	~~7.390¢~~ *8.309¢* per KWH	I

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months	On-Peak	Off-Peak
Approximate Percent (%) Of Annual Hours	16%	84%
Winter Period:		
November 1 to March 31	7:00 A.M. to 11:00 A.M. 6:00 P.M. to 10:00 P.M.	11:00 AM. to 6:00 P.M. 10:00 P.M. to 7:00 A.M.
Summer Period:		
May 15 to September 15	Noon to 6:00 P.M.	6:00 P.M. to Noon
All Other Calendar Periods	None	Midnight to Midnight

NOTE: All KWH consumed during Saturday and Sunday are billed at the off-peak level.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

(Cont'd on Sheet No. 6-12)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-T.O.D.2 (Cont'd)
(Experimental Residential Service Time-of-Day 2)

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment actor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-1of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

(Cont'd on Sheet No. 6-13)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF R.S.-T.O.D.2 (Cont'd)
(Experimental Residential Service Time-of-Day 2)

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

SPECIAL TERMS AND CONDITIONS.

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

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

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

AVAILABILITY OF SERVICE.

Available for general service to customers with average monthly demands less than 10 KW and maximum monthly demands of less than 15 KW (excluding the demand served by the Load Management Time-of-Day provisions). *Service will be provided at Secondary voltage metering only.* N

Customers not meeting the requirements for availability under this tariff will only be permitted to continue service under this tariff at the premise occupied for continuous service beginning no later than January 22, 2015. N

RATE. (Tariff Codes 211, 212)

Service Charge............	~~$11.50~~ $ *19.50* per month	I
Energy Charge:		
First 500 KWH per month............	~~13.160¢~~ *11.500¢* per KWH	R
All Over 500 KWH per month............	~~7.116¢~~ *7.057¢* per KWH	R

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rate set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N–N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1through 38-2 of this Tariff Schedule. N

(Cont'd on Sheet No. 7-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.G.S. (Cont'd.)
(Small General Service)

BIG SANDY I OPERATION RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

(Cont'd. on Sheet 7-3)

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.G.S. (Cont'd.)
(Small General Service)

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE. (Tariff Code 225)

Service Charge..	~~$15.10~~ *$19.50* per month	I
Energy Charge:		
All KWH used during on-peak billing period..................	~~15.326 ¢~~ *13.755¢* per KWH	R
All KWH used during off-peak billing period	~~4.940 ¢~~ *5.216¢* per KWH	I

OPTIONAL UNMETERED SERVICE PROVISION.

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

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

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

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at the following rates:

RATE. (Tariff Codes 204 (Metered), 213 (Unmetered))

Customer Charge..	~~$7.50~~ $*15.50* per month	I
Energy Charge:		
First 500 KWH per month..................................	~~13.160¢~~ *11.500¢* per KWH	R
All Over 500 KWH per month................................	~~7.116¢~~ *7.057¢* per KWH	R

TERM OF CONTRACT.

The Company shall have the right to require contacts for a period of one (1) year or longer.

SPECIAL TERMS AND CONDITIONS.

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

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

(Cont'd on Sheet No. 7-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission
In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 7- 4**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 7- 4

TARIFF S.G.S. – T.O.D.
(~~Experimental~~ Small General Service Time-of-Day Service)

AVAILABILITY OF SERVICE.

Available on a voluntary~~, experimental~~ basis for general service to customers being served at secondary distribution voltage with ~~12-month average demands less than 10 kW through~~ one single-phase, multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff. T

Customers not meeting the requirements for availability under this tariff will only be permitted to continue service under this tariff at the premise occupied for continuous service beginning no later than January 22, 2015. N

RATE. (Tariff Code 227)

Service Charge .... ~~$14.95~~ *$19.50* per month I
Energy Charge:
All KWH used during Summer on-peak billing period .... ~~13.538¢~~ *11.126¢* per KWH R
All KWH used during Winter on-peak billing period .... ~~15.553¢~~ *12.020¢* per KWH R
All KWH used during off-peak billing period .... ~~8.700¢~~ *8.476¢* per KWH R

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months	On-Peak	Off-Peak
Approximate Percent (%) Of Annual Hours	16%	84%
Winter Period: November 1 to March 31	7:00 A.M. to 11:00 A.M. 6:00 P.M. to 10:00 P.M.	11:00 A.M. to 6:00 P.M. 10:00 P.M. to 7:00 A.M.
Summer Period: May 15 to September 15	Noon to 6:00 P.M.	6:00 P.M. to Noon
All Other Calendar Periods	None	Midnight to Midnight

NOTE: All KWH consumed during weekends are billed at the off-peak level.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

(Cont'd on Sheet No. 7-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.G.S.-T.O.D. (Cont'd)
(~~Experimental~~ Small General Service Time-of-Day)

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 and 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 7-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

(~~Experimental~~ Small General Service Time-of-Day) T

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule N

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission
In Case No. 2014-00396 Dated XXXXXXXX

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

AVAILABILITY OF SERVICE.

Available for general service to customers with average monthly demands greater than 10 KW or maximum monthly demands greater than 15 KW, but not more than 100 KW (excluding the demand served by the Load Management Time-of-Day provision). *Except as provided below, customers receiving service on or before January 22, 2015 at a secondary voltage and with average monthly demand below 10 KW will be served under the S.G.S. tariff.* N

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	
Tariff Code	215, 216, 218	217, 220	236	
Service Charge per Month	$ ~~13.50~~ *19.50*	$ ~~25.00~~ *50.00*	$ ~~182.00~~ *364.00*	III
Demand Charge per KW	$ ~~1.64~~ *2.05*	$ ~~1.59~~ *1.99*	$ ~~1.55~~ *1.96*	III
Energy Charge:				
KWH equal to 200 times KW of monthly billing demand	~~9.862¢~~ *10.072¢*	~~9.054¢~~ *9.245¢*	~~8.361¢~~ *8.538¢*	III
KWH in excess of 200 times KW of monthly billing demand	~~8.460¢~~ *8.639¢*	~~8.098¢~~ *8.270¢*	~~7.851¢~~ *8.018¢*	III

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by 6 KW. The minimum monthly charge for industrial and coal mining customers contracting for 3-phase service after October 1, 1959 shall be ~~$6.84~~ $ *8.55* per KW of monthly billing demand. I

RECREATIONAL LIGHTING SERVICE PROVISION.

Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff M.G.S. customers will also apply to recreational lighting customers except for the Availability of Service.

RATE. (Tariff Code 214)

Service Charge .... ~~$ 13.50~~ $ *19.50* per month I
Energy Charge .... ~~9.004¢~~ *10.000¢* per KWH I

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased *or decreased* by ~~an Experimental~~ *a* Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule. T T

(Cont'd on Sheet No. 8-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Of Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-Xxxx Dated Xxxxxxxx

TARIFF M.G.S. (Cont'd.)
(Medium General Service)

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rate set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

(Cont'd on Sheet No. 8-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S (Cont'd)
(Medium General Service)

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Energy supplied hereunder will be delivered through not more than one single phase and/or polyphase meter. Customer's demand will be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The minimum monthly billing demand shall not be less than (a) the minimum billing demand of 6 KW, or (b) 60% of the greater of (1) the customer's contract capacity in excess of 100 KW or (2) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

(Cont'd on Sheet No. 8-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S (Cont'd)
(Medium General Service)

LOAD MANAGEMENT TIME-OF-DAY PROVISION. (Tariff Code 223)

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE.

Service Charge	$ ~~3.00~~	*$ 3.85*	per month	I
Energy Charge:				
All KWH used during on-peak billing period	~~14.801¢~~	*15.757¢*	per KWH	I
All KWH used during off-peak billing period	~~5.130¢~~	*5.491¢*	per KWH	I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

TERM OF CONTRACT.

Contracts under this tariff ~~will~~ *may* be required of customers ~~with normal maximum demands of 500 KW or greater.~~ T
Contracts under this tariff will be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for periods of longer than 1 (one) year. ~~and to require contracts for Customers with normal maximum demands of less than 500 KW.~~ T

SPECIAL TERMS AND CONDITIONS.

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

This tariff is also available to Customers having other source of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum demand in KW which the Company might be required to furnish, but no less than 10 KW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point of both their power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

(Cont'd on Sheet No. 8-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S.-T.O.D.
(Medium General Service Time-of-Day)

AVAILABILITY OF SERVICE.

Available for general service to customers with normal maximum demands greater than 10 KW but not more than 100 KW. Availability is limited to the first 500 customers applying for service under this tariff.

RATE. (Tariff Code 229)

Service Charge	$ ~~14.30~~	$ *19.50* per month	I
Energy Charge: All KWH used during on-peak billing period	~~14.801¢~~	*15.757¢* per KWH	I
All KWH used during off-peak billing period	~~5.130¢~~	*5.491¢* per KWH	I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday.
The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the Service Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

(Cont'd on Sheet No. 8-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S.-T.O.D. (Cont'd)
(Medium General Service Time-of-Day)

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 8-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.G.S.-T.O.D. (Cont'd)
(Medium General Service Time-of-Day)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

SPECIAL TERMS AND CONDITIONS.

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

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 9- 1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 9- 1

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

AVAILABILITY OF SERVICE.

Available for general service to customers with normal maximum demands greater than 100 KW but not more than 1,000 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

RATE.

	Service Voltage				
	Secondary	Primary	Subtransmission	Transmission	
Tariff Code	240, 242	244, 246	248	250	
Service Charge per Month	$ 85.00	$ 127.50	$ ~~535.50~~ *661.65*	$ ~~535.50~~ *661.65*	I I
Demand Charge per KW	$ ~~4.02~~ *5.03*	$ ~~3.89~~ *4.89*	$ ~~3.80~~ *4.83*	$ ~~3.76~~ *4.75*	I I I I
Excess Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46	
Energy Charge per KWH	~~7.795¢~~ *8.056¢*	~~6.514¢~~ *6.851¢*	~~4.942¢~~ *4.670¢*	~~4.644¢~~ *4.579¢*	I I R R

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

(Cont'd. On Sheet No. 9-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. (Cont'd.)
(Large General Service)

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of
revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 9-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. (Cont'd)
(Large General Service)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

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

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

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

RATE. (Tariff Code 251)

Service Charge	~~$ 81.80~~ *$ 85.00*	per month	I
Energy Charge:			
All KWH used during on-peak billing period	~~12.971¢~~ *13.164¢*	per KWH	I
All KWH used during off-peak billing period	~~5.116¢~~ *5.471¢*	per KWH	I

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

(Cont'd on Sheet No. 9-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. (Cont'd)
(Large General Service)

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 *(one)* year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 *(one)* year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required. T T

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

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

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

(Cont'd on Sheet No. 9-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 9-5**
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 9-5

TARIFF L.G.S. – T.O.D.
(Large General Service – Time of Day)

AVAILABILITY OF SERVICE.

Available for general service customers with normal maximum demands of 100 KW or greater. Customers may continue to qualify for service under this tariff until their 12-month average demand exceeds 1,000 KW. Availability is limited to the first 500 customers applying for service under this tariff.

RATE.

	Service Voltage				
	Secondary	Primary	Subtransmission	Transmission	
Tariff Code	256	257	258	259	
Service Charge per Month	$ 85.00	$ 127.50	$ ~~535.50~~ *661.65*	$ ~~535.50~~ *661.65*	II
Demand Charge per KW	$ ~~7.64~~ *10.20*	$ ~~4.58~~ *7.35*	$ ~~0.24~~ *1.08*	$ ~~0.15~~ *1.07*	IIII
Excessive Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46	
On-Peak Energy Charge per KWH	~~9.778¢~~ *8.481¢*	~~7.959¢~~ *8.187¢*	~~7.729¢~~ *8.098¢*	~~7.655¢~~ *8.002¢*	IIII
Off-Peak Energy Charge per KWH	~~4.116¢~~ *4.533¢*	~~3.965¢~~ *4.411¢*	~~3.891¢~~ *4.374¢*	~~3.854¢~~ *4.334¢*	IIII

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., for all weekdays Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

(Cont'd on Sheet No. 9-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. – T.O.D. (Cont'd.)
(Large General Service – Time of Day)

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

(Cont'd on Sheet 9-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. – T.O.D. (Cont'd)
(Large General Service – Time of Day)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional Charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

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

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

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

(Cont'd on Sheet No. 9-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF L.G.S. – T.O.D. (Cont'd)
(Large General Service – Time of Day)

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

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

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 10- 1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 10- 1

TARIFF I.G.S.
(Industrial General Service) N

AVAILABILITY OF SERVICE.

Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet normal maximum requirements.

RATE.

			Service Voltage	
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	356	358/370	359/371	360/372
Service Charge per month	$ 276.00	$ 276.00	$ 794.00	$ 1,353.00
Demand Charge per KW				
Of monthly on-peak billing demand	$ 20.69	$ 17.46	$ 10.74	$ 10.45
Of monthly off-peak billing demand	$ 1.13	$ 1.10	$ 1.08	$ 1.07
Energy Charge per KWH	3.398¢	3.279¢	3.242¢	3.204¢

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand .... $0.69/ KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

MINIMUM DEMAND CHARGE.

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	Primary	Subtransmission	Transmission
$22.06/KW	$18.80 /KW	$12.07/KW	$11.76/KW

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule. N

(Cont'd on Sheet No. 10-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF I.G.S.
(Industrial General Service) N

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.

BIG SANDY RETIREMENT RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule.

BIG SANDY I OPERATION RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule.

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M.RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

(Cont'd on Sheet No. 10-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF I.G.S.
(Industrial General Service)

N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

N

(Cont'd on Sheet No. 10-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF I.G.S.
(Industrial General Service) N

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY

The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiples of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

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

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 11-1
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 11-1

RESERVED FOR FUTURE USE

~~TARIFF C.I.P. - T.O.D.~~
~~(Commercial and Industrial Power – Time-of-Day)~~ D

~~AVAILABILITY OF SERVICE.~~

~~Available for commercial and industrial customers with normal maximum demands of 7,500 KW and above. Customers shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements, but in no case shall the capacity contracted for be less than 7,500 KW.~~

~~RATE.~~

	~~Primary~~	~~Subtransmission~~	~~Transmission~~
~~Tariff Code~~	~~370~~	~~371~~	~~372~~
~~Service Charge per Month~~	~~$ 276.00~~	~~$ 794.00~~	~~$1,353.00~~
~~Demand Charge per KW~~			
~~On-peak~~	~~$ 16.77~~	~~$ 12.06~~	~~$ 10.98~~
~~Off-peak~~	~~$ 5.56~~	~~$ 1.20~~	~~$ 1.10~~
~~Energy Charge per KWH~~	~~2.962¢~~	~~2.906¢~~	~~2.880¢~~

~~Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand~~ $0.69/KVAR

~~For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.~~

~~MINIMUM DEMAND CHARGE.~~

~~The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:~~

~~Primary~~	~~Subtransmission~~	~~Transmission~~
~~$16.88 /KW~~	~~$12.17/KW~~	~~$11.09/KW~~

~~The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.~~

~~MINIMUM CHARGE.~~

~~This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.~~

~~FUEL ADJUSTMENT CLAUSE.~~

~~Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.~~

~~SYSTEM SALES CLAUSE.~~

~~Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.~~

~~DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.~~

~~Bills computed according to the rates set forth herein will be increased or by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 of this Tariff Schedule, unless the KWH is an industrial who has elected to opt-out in accordance with the terms~~ D

DATE OF ISSUE: December 22, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

Issued By: JOHN A. ROGNESS III

Title: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 11-2
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 11-2

RESERVED FOR FUTURE USE

~~TARIFF C.I.P. - T.O.D. (Cont'd.)~~
~~(Commercial and Industrial Power - Time-of-Day)~~ D

~~ASSET TRANSFER RIDER.~~

~~Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 of this Tariff Schedule.~~

~~PURCHASE POWER ADJUSTMENT.~~

~~Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.~~

~~ENVIRONMENTAL SURCHARGE.~~

~~Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.~~

~~CAPACITY CHARGE.~~

~~Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.~~

~~DELAYED PAYMENT CHARGE.~~

~~This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.~~

~~METERED VOLTAGE.~~

~~The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:~~

~~(1) Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.~~
~~(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.~~

~~MONTHLY BILLING DEMAND.~~

~~The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.~~

~~The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVAR's as registered during the month by the demand meter or indicator, or, at the Company's option, as the highest registration of a thermal type demand meter or indicator.~~ D

~~(Cont'd on Sheet No. 11-3)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE

~~TARIFF C.I.P. – T.O.D. (Cont'd)~~
~~(Commercial and Industrial Power – Time-of-Day)~~ D

~~TERM OF CONTRACT.~~

~~Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.~~

~~A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.~~

~~CONTRACT CAPACITY.~~

~~The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount equal to or greater than 7,500 KW, in multiples of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.~~

~~SPECIAL TERMS AND CONDITIONS.~~

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

~~This tariff is also available to customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 7,500 KW. The Company shall not be obligated to supply demands in excess of the contract for capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.~~

~~A customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by customer. When the size of the customer's load necessitates the delivery of energy to the customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the customer's system irrespective of contrary provisions in Terms and Conditions of Service.~~

~~This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.~~

~~Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.~~ D

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power)

AVAILABILITY OF SERVICE.

Available for service to customers who contract for service under one of the Company's interruptible service options. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to ~~60,000~~ *75,000 kW.* T

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

CONDITIONS OF SERVICE.

The Company will offer eligible customers the option to receive service from a menu of interruptible power options pursuant to a contract agreed to by the Company and the Customer.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written offer containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet normal maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than 1,000 KW at any delivery point.

RATE. (Tariff Code 321)

Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's rules as capacity for the purpose of the Company's FRR obligation. N

Charges for the service under this tariff will be set forth in the written agreement between the Company and the Customer and will reflect a difference from the firm service rates otherwise available to the Customer.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to he rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

(Cont'd on Sheet No. 12-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule, unless the Customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rate set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 and 28-2 of this Tariff Schedule.

(Cont'd on Sheet No. 12-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated Xxxxxxxx

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

TERM OF CONTRACT

The length of the agreement and the terms and conditions of service will be stated in the agreement between the Company and the Customer.

CONFIDENTIALITY

All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807 KAR5:001, Section 7 and the request is granted.

(Cont'd on Sheet No. 12-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

SPECIAL TERMS AND CONDITIONS

Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of Service.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist, the Customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 1,000 KW.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company

TARIFF M.W.
(Municipal Waterworks)

AVAILABILITY OF SERVICE.

Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the Customer on this date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load, which the Company may be required to furnish.

RATE. (Tariff Code 540)

Service Charge .... $ 22.90 per month
Energy Charge:
All KWH Used Per Month .... ~~8.300¢~~ *8.601¢* per KWH I

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus ~~$4.10~~ *$ 8.20 per* KVA as determined from customer's total connected load. I

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 *through 22-13* of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N | N

(Cont'd on Sheet No. 13-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.W. (Cont'd)
(Municipal Waterworks)

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 and 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission

(Cont'd on Sheet No. 13-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF M.W. (Cont'd)
(Municipal Waterworks)

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

PAYMENT.

Bills will be rendered monthly and will be due and payable on or before the due date stated on the bill.

TERM OF CONTRACT.

Contracts under this tariff will be made for not less than (1) one year with self-renewal provisions for successive periods of (1) one year each until either party shall give at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than (1) one year.

SPECIAL TERMS AND CONDITIONS.

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

This tariff is not available to customers having other sources of energy supply.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 14-1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 14-1

TARIFF O.L.
(Outdoor Lighting)

AVAILABILITY OF SERVICE.

Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable.

RATE.

A. OVERHEAD LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
094		100 watts (9,500 Lumens)	$ ~~8.75~~ *9.65* per lamp	I
113		150 watts (16,000 Lumens)	$ ~~9.90~~ *10.95* per lamp	I
097		200 watts (22,000 Lumens)	$ ~~12.20~~ *13.45* per lamp	I
103		250 watts (28,000 Lumens)	$ ~~13.35~~ *18.10* per lamp	I
098		400 watts (50,000 Lumens)	$ ~~19.15~~ *21.05* per lamp	I
	2.	Mercury Vapor		
093*		175 watts (7,000 Lumens)	$ ~~9.75~~ *10.75* per lamp	I
095*		400 watts (20,000 Lumens)	$ ~~16.85~~ *18.60* per lamp	I

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. POST-TOP LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
111		100 watts (9,500 Lumens)	$ ~~13.10~~ *14.45* per lamp	I
122		150 watts (16,000 Lumens)	$ ~~21.45~~ *23.70* per lamp	I
121		100 watts Shoe Box (9,500 Lumens)	$ ~~20.00~~ *33.50* per lamp	I
120		250 watts Shoe Box (28,000 Lumens)	$ ~~24.00~~ *50.05* per lamp	I
126		400 watts Shoe Box (50,000 Lumens)	$ ~~27.90~~ *44.10* per lamp	I
	2.	Mercury Vapor		
099*		175 watts (7,000 Lumens)	$ ~~11.20~~ *12.30* per lamp	I

*Effective June 29, 2010 and thereafter these lamps are not available for new installations

Company will provide lamp photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits.

(Cont'd on Sheet 14-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

RATE. (Cont'd.)

C. FLOOD LIGHTING SERVICE

Tariff Code				
	1.	High Pressure Sodium		
107		200 watts (22,000 Lumens)...............................	$ ~~13.60~~ *15.00* per lamp	I
109		400 watts (50,000 Lumens)................................	$ ~~18.85~~ *20.80* per lamp	I
	2.	Metal Halide		
110		250 watts (20,500 Lumens)...............................	$~~18.20~~ *20.10* per lamp	I
116		400 watts (36,000 Lumens)................................	$ ~~24.10~~ *26.60* per lamp	I
131		1000 watts (110,000 Lumens)	$ ~~52.20~~ *67.35* per lamp	I
130		250 watts Mongoose (19,000 Lumens)	$ ~~21.80~~ *25.30* per lamp	I
136		400 watts Mongoose (40,000 Lumens)	$ ~~25.50~~ *30.30* per lamp	I

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

Wood pole..	$ ~~2.85~~ *3.15* per month	I
Overhead wire span not over 150 feet	$ ~~1.60~~ *1.75* per month	I
Underground wire lateral not over 50 feet..	$ ~~6.25~~ *6.90* per month	I
(Price includes pole riser and connections)		

(Cont'd on Sheet No. 14-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 14-3
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 14-3

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule. The monthly kilowatt-hours for Fuel Adjustment Clause, System Sales Clause and the Capacity Charge computations are as follows:

	METAL HALIDE			MERCURY VAPOR		HIGH PRESSURE SODIUM				
	250 WATTS	400 WATTS	1000 WATTS	175 WATTS	400 WATTS	100 WATTS	150 WATTS	200 WATTS	250 WATTS	400 WATTS
JAN	127	199	477	91	199	51	74	106	130	210
FEB	106	167	400	76	167	43	62	89	109	176
MAR	106	167	400	76	167	43	62	89	109	176
APR	90	142	340	65	142	36	53	76	93	150
MAY	81	127	304	58	127	32	47	68	83	134
JUNE	72	114	272	52	114	29	42	61	74	120
JULY	77	121	291	55	121	31	45	65	79	128
AUG	88	138	331	63	138	35	51	74	90	146
SEPT	96	152	363	69	152	39	57	81	99	160
OCT	113	178	427	81	178	45	66	95	116	188
NOV	119	188	449	86	188	48	70	100	122	198
DEC	129	203	486	92	203	52	75	108	132	214
TOTAL	1204	1896	4540	864	1896	484	704	1012	1236	2000

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.*

BIG SANDY RETIREMENT RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule.

BIG SANDY I OPERATION RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule.

(Cont'd. on Sheet No. 14-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF O.L. (Cont'd.)
(Outdoor Lighting)

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule. N

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

OWNERSHIP OF FACILITIES.

All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company.

The Company shall be allowed 3 working days after notification by the customer to replace all burned-out lamps.

TERM OF INITIAL SERVICE.

Term of initial service shall be required for a period of one year. *If early termination is requested, the customer will be billed for the remainder of the 12 month period.* N

SPECIAL TERMS AND CONDITIONS.

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

The Company shall have the option of rendering monthly or bimonthly bills.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.L.
(Street Lighting)

AVAILABILITY OF SERVICE.

Available for lighting service for all the lighting of public streets, public highways and other public outdoor areas in municipalities, counties, and other governmental subdivisions where such service can be supplied from the existing general distribution systems.

RATE. (Tariff Code 528)

A. Overhead Service on Existing Distribution Poles

1. High Pressure Sodium

100 watts (9,500 lumens)	$	~~7.25~~ *8.05* per lamp	I
150 watts (16,000 lumens)	$	~~8.30~~ *9.25* per lamp	I
200 watts (22,000 lumens)	$	~~10.30~~ *11.45* per lamp	I
400 watts (50,000 lumens)	$	~~16.05~~ *17.80* per lamp	I

B. Service on New Wood Distribution Poles

1. High Pressure Sodium

100 watts (9,500 lumens)	$	~~10.25~~ *11.35* per lamp	I
150 watts (16,000 lumens)	$	~~11.40~~ *12.60* per lamp	I
200 watts (22,000 lumens)	$	~~13.15~~ *14.60* per lamp	I
400 watts (50,000 lumens)	$	~~18.45~~ *20.45* per lamp	I

C. Service on New Metal or Concrete Poles*

1. High Pressure Sodium

100 watts (9,500 lumens)	$	~~18.90~~ *20.95* per lamp	I
150 watts (16,000 lumens)	$	~~19.85~~ *22.00* per lamp	I
200 watts (22,000 lumens)	$	~~25.25~~ *28.00* per lamp	I
400 watts (50,000 lumens)	$	~~27.45~~ *30.45* per lamp	I

*Effective June 29, 2010 and thereafter these lamps are not available for new installations

Lumen rating is based on manufacturer's rated lumen output for new lamps.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule. The monthly kilowatt-hours for Fuel Adjustment Clause, System Sales Clause and the Capacity Charge computations are as follows:

(Cont'd on Sheet No. 15-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.L. (Cont'd.)
(Street Lighting)

FUEL ADJUSTMENT CLAUSE. (Cont'd.)

	HIGH PRESSURE SODIUM			
MONTH	100 WATTS	150 WATTS	200 WATTS	400 WATTS
JAN	51	74	106	210
FEB	43	62	89	176
MAR	43	62	89	176
APR	36	53	76	150
MAY	32	47	68	134
JUNE	29	42	61	120
JULY	31	45	65	128
AUG	35	51	74	146
SEPT	39	57	81	160
OCT	45	66	95	188
NOV	48	70	100	198
DEC	52	75	108	214
TOTAL	484	704	1012	2000

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. *The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.* N N

BIG SANDY RETIREMENT RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule. N

BIG SANDY I OPERATION RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule. N

(Cont'd On Sheet No. 15-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S.L. (Cont'd.)
(Street Lighting)

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1through 28-2 of this Tariff Schedule.

P.J.M.RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule N

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE. N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission. N

NERC COMPLIANCE AND CYBERSECURITY RIDER. N

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cybersecurity Rider Adjustment Factor per kWh calculated in compliance with the NERC Compliance and Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule. N

SPECIAL FACILITIES.

When a customer requests street lighting service which requires special poles or fixtures, underground street lighting, or a line extension of more than one span of approximately 150 feet, the customer will be required to pay, in advance, an aid-to-construction in the amount of the installed cost of such special facilities

PAYMENT.

Bills are due and payable within ten (10) days of the mailing date.

HOURS OF LIGHTING.

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

TERM OF CONTRACT.

Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company may have the right to require contracts for periods of longer than one year if new or additional facilities are required.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 16-1
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 16-1

TARIFF C. A. T. V.
(Cable Television Pole Attachment)

AVAILABILITY OF SERVICE.

Available to operators of cable television systems (Operators) furnishing cable television service in the operating area of Kentucky Power Company (Company) for attachments of aerial cables, wires and associated appliances (attachments) to certain distribution poles of Kentucky Power Company.

As used in this Tariff, an "attachment" shall mean the physical connection of (a) a messenger strand supporting the wires, cables or stand-mounted associated facilities and equipment of a cable system or (b) service drops affixed to the pole and located more than one vertical foot away from the point at which the messenger strand is attached to the pole (but not a strand originating or mid-span service drop) or (c) service drops located on a dedicated service, drop or lift pole. An attachment shall consume no more than one foot (1') of vertical space on any distribution pole owned by the Company. N

RATE.

Charge for attachments on a two-user pole .... $ 7.21 per ~~pole/year~~ *attachment per year* T
Charge for attachments on a three-user pole .... $ 4.47 per ~~pole/year~~ *attachment per year* T

The above rate was calculated in accordance with the following formula:

Weighted Average Bare Pole Cost	x	Usage Factor	x	Carrying Charge		= Rate Per Pole

A two-user pole is a pole being used, by actual occupation or reservation, by the Operator and the Company. A three-user pole is a pole being used by actual occupation or reservation, by the Operator, the Company, and a third party. N

DELAYED PAYMENT CHARGE.

This Tariff is net if account is paid in full within ~~15~~ *30* days of date of bill. On all accounts not so paid an additional charge of 5% of the unpaid balance will be made. T

POLE SUBJECT TO ATTACHMENT.

When an Operator proposes to furnish cable television service within the Company's operating area and desires to make attachments on certain distribution poles of Company, Operator shall make written application, on a form furnished by Company, to install attachments specifying the location of each pole in question, the character of its proposed attachments and the amount and location of space desired, and any other information necessary to calculate the transverse and vertical load placed upon the pole as a result of the proposed attachment and any other facilities attached to the pole. Within ~~twenty- one (21)~~ *forty-five (45)* days after receipt of the application, Company shall notify Operator whether and to what extent any special conditions will be required to permit the use by Operator of each such pole. Operator shall reimburse Company for any expenses incurred in reviewing such written applications for attachment. Operator shall have a non-exclusive right to use such poles of Company as may be used or reserved for use by Operator and any other poles of Company when brought hereunder in accordance with the procedure hereinafter provided. Company shall have the right to grant, by contract or otherwise to others rights or privileges to use any poles of the Company and Company shall have the right to continue and extend any such rights or privileges heretofore granted. All poles shall be and remain the property of Company regardless of any payment by Operator toward their cost and Operator shall, except for the rights provided hereunder, acquire no right, title or interest in or to any such pole. T

(Cont'd on Sheet No. 16-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

STANDARDS FOR INSTALLATION.

All attachments and associated equipment of Operator (including without limitation, power supplies) shall be installed in a manner satisfactory to Company and so as not to interfere with the present or any future use which Company may desire to make of the poles covered by this Tariff. All such attachments and equipment shall be installed and at all times maintained by Operator so as to comply at least with the minimum requirements of the National Electrical Safety Code and any other applicable regulations or codes promulgated by state, local or other governmental authority having jurisdiction there over. Power supply apparatus having as its largest dimension more than sixteen inches must be placed on a separate pole to be installed by Operator. Operator shall take necessary precautions by the installation of protective equipment or other means, to protect all persons and property of all kinds against injury or damage occurring by reason of Operator's attachments.

POLE INSTALLATION OR REPLACEMENT; REARRANGEMENTS; GUYING.

In any case Operator proposes to install attachments on a pole to be erected by Company in a new location, and to provide adequate space or strength to accommodate such attachments (either at the request of Operator to comply with the aforesaid codes and regulations) such pole must, in Company's judgment, be taller and/or stronger than would be necessary to accommodate the facilities of Company and of other persons who have previously indicated that they desire to make attachments on such pole or with whom Company has an agreement providing for joint or share ownership of poles, the cost of such extra height and/or strength shall be paid to Company by Operator. Such cost shall be the difference between the cost in place of the new pole and the current cost in place of a pole considered by Company to be adequate for the facilities of Company and the attachments of such other persons.

Where in Company's judgment a new pole must be erected to replace an existing pole solely to adequately provide for Operator's proposed attachments, Operator agrees to pay Company for the entire cost of the new pole necessary to accommodate the existing facilities on the pole and Operator's proposed attachments, plus the cost of removal of the in-place pole, minus the salvage value, if any, of the removed pole. Title to the new pole shall remain with the Company. Operator shall also pay to Company and to any other owner of existing attachments on the pole the cost of removing each of their respective facilities or attachments from the existing pole and reestablishing the same or like facilities or attachments on the newly-installed pole.

If Operator's desired attachments can be accommodated on existing poles of Company by rearranging facilities of Company thereon of any other person, or if because of Operator's proposed attachments it is necessary for Company to rearrange its facilities on any pole not owned by it, then in any such case, Operator shall reimburse Company and any such other person for the respective expense incurred in making such rearrangement.

If because of the requirements of its business, Company proposed to replace an existing pole on which Operator has any attachment, or Company proposed to change the arrangements of its facilities on any such pole in such manner as to necessitate a rearrangement of Operator's attachment, or if as a result of any inspection of Operator's attachments Company determines that any such attachments are not in accordance with applicable codes or the provisions of this Tariff or are otherwise hazards Company shall give Operator not less than 48 hours notice of such proposed replacement or change, or any such violation or hazard, unless an emergency requires a shorter period. In such event, Operator shall at its expense relocate, rearrange or modify its attachments at the time specified by Company. If Operator fails to do so, or if any such emergency makes notice impractical, Company shall perform such relocation or rearrangement and Operator shall reimburse Company for the reasonable cost thereof.

Any additional guying or anchors required by reason of the attachments of Operator shall be provided at the expense of Operator and shall meet the requirements of all applicable codes or regulations and Company's generally applicable guying standards.

(Cont'd on Sheet No. 16-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

POLE INSPECTION.

Company may make periodic inspections, as conditions may warrant, for the purpose of determining compliance with the provisions of this Tariff. Company reserves the right to inspect each new or proposed installation of Operator on Company's poles. In addition, Company's right to make any inspections and any inspection made pursuant to such right shall not relieve Operator of any responsibility, obligation or liability assumed under this Tariff.

UNAUTHORIZED ATTACHMENTS.

Operator shall make no attachment to or other use of any pole of Company or any facilities of Company thereon, except as authorized. *The company reserves the right to make periodic inspections.* Should such unauthorized attachment or use be made, Operator shall pay N to the Company on demand two times the charges and fees, including but not limited to, any payable under the headings "RATES" and "POLE INSTALLATION OR REPLACEMENT; REARRANGEMENTS; GUYING" that would have been payable had such attachment been made on the date following the date of the last previous inspection required to be made by Company under applicable regulations of the Kentucky Public Service Commission.

ABANDONMENT BY OPERATOR.

Operator may at any time abandon the use of a pole hereunder by removing therefrom all of its attachments and by giving written notice thereof, on a form provided by the Company, and no pole shall be considered abandoned until such notice is received.

INDEMNITY.

Operator hereby agrees to indemnify, hold harmless, and defend Company from and against any and all loss, damage, cost or expense which Company may suffer or for which Company may be held liable because of interruption of Operator's service to its subscribers or because of interference with television reception of said subscribers or others, or by reason of bodily injury, including death, to any person, or damage to or destruction of any property, including loss of use thereof, arising out of or in any manner connected with the attachment, operation, and maintenance of the facilities of Operator on the poles of Company under this Tariff, when due to any act, omission or negligence of Operator, or to any such act, omission or negligence of Operator's respective representatives, employees, agents or contractors.

INSURANCE.

Operator agrees to obtain and maintain at all times policies of insurance as follows:

(a) Comprehensive bodily injury liability insurance in an amount not less than $1,000,000 for any one occurrence
(b) Comprehensive property damage liability insurance in an amount not less than $500,000 for any one occurrence.
(c) Contractual liability insurance in an amount not less than the foregoing minimums to cover the liability assumed by the Operator under the agreement or indemnity set forth above.

Prior to making attachments at Company's poles, Operator shall furnish to Company two copies of a certificate, from an insurance carrier licensed to do business in Kentucky, stating that policies of insurance have been issued by it to Operator providing for the insurance listed above and that such policies are in force. Such certificate shall state that the insurance carrier will give Company *thirty* T *(30)* ~~fifteen (15)~~ days' prior written notice of any cancellation of or material change in such policies.

(Cont'd on Sheet 16-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C.A.T.V. (Cont'd.)
(Cable Television Pole Attachment)

EASEMENTS.

Operator shall secure any right, license or permit from any governmental body, authority or other person or persons which may be required for the construction or maintenance of attachments of Operator. Company does not convey nor guarantee any easements, rights-of-way or franchises for the construction and maintenance of said attachments. Operator hereby agrees to indemnify and save harmless Company from any and all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Operator to secure such right, license, permit or easement for the construction or maintenance of said attachments on Company's poles.

CHARGES AND FEES.

Operator agrees to pay Company *an annual charge per attachments set forth on Tariff Sheet No. 16-1* in advance, ~~semi-annually~~, ~~charges to be computed as set forth in Tariff~~, and such other charges as may be provided for herein, for the use of each of Company's poles, any portion of which is occupied by, or reserved at Operator's request for the attachments of Operator. N

Operator agrees to reimburse Company for all reasonable non-recurring expenses caused by or attributable to Operator's initial attachments including without limitation the amounts set forth herein before and the expenses of Company in examining poles used but not owned by Company to which Operator proposes to make attachments.

FEES FOR ADDITIONAL ATTACHMENTS OR REMOVALS.

For attachments made or removed which are reported to the Company between billing dates, Operator shall be billed or credited a prorated amount of the annual charge effective with the date of attachment or removal on the Operator's next bill.

ADVANCE BILLING

Payment of amounts due hereunder is due on the dates or at the times indicated with respect to each such payment. In the event the time for any payment is not specified, such payment shall be due ~~fifteen (15)~~ *thirty (30)* days from the date of the invoice therefore. In all amounts not so paid an addition charge of five percent (5%) will be assessed. Where the provisions of the Tariff require any payment by Operator to the Company other than for attachment charges, Company may, at its option, require that the estimated amount thereof be paid in advance of permission to use any pole or the performance by company of any work. In such a case, Company shall invoice any deficiency or refund any excess to Operator after the current amount of such payment has been determined. T

DEFAULT OR NON-COMPLIANCE.

If Operator fails to comply with any of the provisions of this Tariff or defaults in the performance of any of its obligations under this Tariff and fails within thirty (30) days, after written notice from Company to correct such default or non-compliance, Company may, *in addition to all other remedies under this tariff* ~~as its option~~ forthwith take any one or more of the following actions: terminate the specific permit or permits covering the poles to which such default or non-compliance is applicable; remove, relocate or rearrange attachments of Operator to which such default or non-compliance relates, all at Operator's expense; decline to permit additional attachments hereunder until such default is cured; or in the event of any failure to pay any of the charges, fees or amounts provided in this Tariff or any other substantial default, or of repeated defaults terminate Operator's right of attachment. No liability shall be incurred by Company because of any or all such actions except for negligent destruction by the Company of CATV equipment in any relocation or removal of such equipment. The remedies provided herein are cumulative and in addition to any other remedies available to Company. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF C. A. T. V. (Cont'd)
(Cable Television Pole Attachment)

PRIOR AGREEMENTS.

This Tariff terminates and supersedes any previous agreement, license or joint use affecting Company's poles and Operator's attachments covered herein.

ASSIGNMENT.

This Tariff shall be binding upon and inure to the benefits of the parties hereto, their respective successors and/or assigns, but Operator shall not assign, transfer or sublet any of the rights hereby granted without the prior written consent of the Company, which shall not be unreasonably withheld, and any such purported assignment, transfer or subletting without such consent shall be void.

PERFORMANCE WAIVER.

Neither party shall be considered in default in the performance of its obligations herein, or any of them, to the extent that performance is delayed or prevented due to causes beyond the control of said party, including but not limited to, Acts of God or the public enemy, war, revolution, civil commotion, blockade or embargo, acts of government, any law, order, proclamation, regulation, ordinance, demand, or requirement of any government, fires, explosions, cyclones, floods, unavoidable casualties, quarantine, restrictions, strikes, labor disputes, lock-outs, and other causes beyond the reasonable control of either of the parties.

PRESERVATION OF REMEDIES.

No delay or omission in the exercise of any power or remedy herein provided or otherwise available to the Company shall impair or affect its right thereafter to exercise the same.

~~HEADINGS.~~ D

~~Headings used in this Tariff are inserted only for the convenience of the parties and shall not affect the interpretation or construction of this Tariff.~~ D

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP I
(Cogeneration and/or Small Power Production--100 KW or Less)

AVAILABILITY OF SERVICE.

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a total design capacity of 100 KW or less. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1- The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

MONTHLY CHARGES FOR DELIVERY FROM THE COMPANY TO THE CUSTOMER.

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - *Not Applicable.* N
~~Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.~~ D
|
D

(Cont'd on Sheet No. 17-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP I (Cont'd.)
(Cogeneration and/or Small Power Production--100 KW or Less)

ADDITIONAL CHARGES. (Cont'd.)

Monthly Metering Charge (Cont'd.)

Options 2 & 3 - Where meters are used to measure the excess or total energy and average on-peak capacity purchased by the Company:

	Single Phase	Polyphase	
Standard Measurement	~~$ 6.75~~ *$ 8.50*	~~$7.75~~ *$ 11.10*	I I
T.O.D. Measurement	~~$ 7.15~~ *$ 9.05*	~~$8.10~~ *$ 11.40*	I I

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each use.

Local Facilities Charge

Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH	~~2.90¢~~ *3.79¢* KWH	I
T.O.D. Meter		
On-Peak KWH	~~3.06¢~~ *4.64¢* KWH	I
Off-Peak KWH	~~2.78¢~~ *3.18¢* KWH	I

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

(Cont'd on Sheet No. 17-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP I (Cont'd.)
(Cogeneration and/or Small Power Production--100 KW or Less)

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES. (Cont'd.)

Capacity Credit (Cont'd.)

If standard energy meters are used,

A. $ ~~2.84~~ *3.70* KW/month, times the lowest of: I

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used,

B. ~~$6.82~~ *8.87* KW/month, times the lowest of: I

(1) on-peak contract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by ~~327~~,*305* or T

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

ON-PEAK AND OFF-PEAK PERIODS.

The on-peak period shall be defined as starting at 7:00A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00A.M. local time, Monday through Friday, and all hours of Saturday and Sunday.

CHARGES FOR CANCELLATION OR NON PERFORMANCE CONTRACT.

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP I or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

TERM OF CONTRACT.

Contracts under this tariff shall be made for a period not less than one year.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP II
(Cogeneration and/or Small Power Production--Over 100 KW)

AVAILABILITY OF SERVICE.

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a total design capacity of over 100 KW but less than 20,000 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

MONTHLY CHARGES FOR DELIVERY FROM THE COMPANY TO THE CUSTOMER.

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - *Not Applicable.* N
~~Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.~~ D | D

(Cont'd on Sheet No. 18-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP II (Cont'd.)
(Cogeneration and/or Small Power Production--Over 100 KW)

ADDITIONAL CHARGES. (Cont'd.)

Monthly Metering Charge (Cont'd)

Options 2 & 3- Where meters are used to measure the excess or total energy and average on peak capacity purchased by the Company:

	Single Phase	Polyphase	
Standard Measurement	$ ~~6.75~~ *8.50*	$ ~~7.75~~ *11.10*	I I
T.O.D. Measurement	$ ~~7.15~~ *9.05*	$ ~~8.10~~ *11.40*	I I

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

Local Facilities Charge

Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH .... ~~2.90¢~~ *3.79¢ KWH* I

T.O.D. Meter
On-Peak KWH .... ~~3.06¢~~ *4.64¢* KWH I
Off-Peak KWH .... ~~2.78¢~~ *3.18¢* KWH I

(Cont'd on Sheet No. 18-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF COGEN/SPP II (Cont'd.)
(Cogeneration and/or Small Power Production--Over 100 KW)

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES. (Cont'd.)

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. $~~2.84~~ *3.70*/KW/ month, times the lowest of: I

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730,or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used,

B. $~~6.82~~ *8.87*/KW/month, times the lowest of: I

(1) on-peak contract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by ~~730~~ *305*, or T

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

ON-PEAK AND OFF-PEAK PERIODS.

The on-peak period shall be defined as starting at 7:00 A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00 A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

CHARGES FOR CANCELLATION OR NON PERFORMANCE CONTRACT.

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP II or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

TERM OF CONTRACT.

Contracts under this tariff shall be made for a period not less than one year.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S. S. C.
(System Sales Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., ~~Experimental~~ S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ~~Q.P., C.I.P.-T.O.D.~~, *I.G.S.*, C.S.- I.R.P., M.W., O.L. and S.L. T T

RATE.

~~In accordance with the Stipulation and Settlement Agreement approved as modified by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the System Sales Adjustment Factor will be fixed and maintained at 0.0000 mills/kWh until new base rates are first established by Commission after the effective date of this tariff without regard to the calculation of the Monthly System Sales Adjustment Factor under paragraphs 1 through 6 below.~~ D D

1. When the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as provided in paragraph 2 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   System Sales Adjustment Factor (A) = (.6 [Tm - Tb])/Sm

   In the above formulas "T" is Kentucky Power Company's (KPCo) monthly net revenues from system sales in the current (m) and base (b) periods, and "S" is the KWH sales in the current (m) period, all defined below.

2. *The net revenue from KPCo's sales to non-associated companies as reported in the FERC Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:* N

   a. *KPCo's total revenues from system sales as recorded in Account 447, less b. and c. below.*

   b. *KPCo's total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.*

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

   c. *KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.* N

(Cont'd on Sheet No. 19-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF S. S. C. (Cont'd.)
(System Sales Clause)

3. The base monthly net revenues from system sales are as follows:

Billing Month	System Sales (Total Company Basis)		
January	$ ~~528.886~~	*1,560,360*	I
February	~~335,167~~	*1,335,811*	I
March	~~1,530,489~~	*1,296,845*	R
April	~~1,371,521~~	*1,152,503*	R
May	~~1,307,472~~	*1,170,480*	R
June	~~767,124~~	*1,106,499*	I
July	~~616,234~~	*1,322,384*	I
August	~~2,136,652~~	*1,031,319*	R
September	~~1,850,577~~	*1,038,816*	R
October	~~1,739,665~~	*1,088,125*	R
November	~~1,538,455~~	*1,123,099*	R
December	~~1,568,121~~	*1,073,722*	R
	$~~15,290,363~~	*$14,299,964*	R

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon estimated monthly revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

6. The monthly System Sales Clause shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF F.T.
(Franchise Tariff)

AVAILABILITY OF SERVICE.

Where a city or town within Kentucky Power's service territory requires the Company to pay a percentage of revenues from certain customer classifications collected within such city or town of the right to erect the Company's poles, conductors, or other apparatus along, over, under, or across such city's or town's streets, alleys, or public grounds, the Company shall increase the rates and charges to such customer classifications within such city or town by a like percentage. The aforesaid charge shall be separately stated and identified on each affected customer's bill.

TARIFF T. S.
(Temporary Service)

AVAILABILITY OF SERVICE.

Where capacity is available, *Company will install service* for temporary lighting and power service. *Residential customers will be supplied with 100 amp service. All other customer classes will be supplied at voltage levels applicable to the class of business.* N

RATE. *(Tariff Code 019)* T

Temporary service will be supplied under any published tariff applicable to the class of business of the Customer, when the Company has available unsold capacity of lines, transforming and generating equipment, with an additional charge of the total cost of connection and disconnection.

MINIMUM CHARGE.

The same minimum charge as provided for in any applicable tariff shall be applicable to such temporary service and for not less than one full monthly minimum.

TERM.

Variable. *Initial period of 180 days. The Company may extend for an additional 90 day period.* N

SPECIAL TERMS AND CONDITIONS.

A deposit equal to the full estimated amount of the bill and/or construction costs under this tariff may be required.

This tariff is not available to customers permanently located, whose energy requirements are of a seasonal nature.

See Terms and Conditions of Service.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(Demand-Side Management Adjustment Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., Experimental S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ~~Q.P., C.I.P.-T.O.D.~~,*I.G.S.*, C.S.-I.R.P., and M.W. T

RATE.

1. The Demand-Side Management (DSM) clause shall provide for periodic adjustment per KWH of sales equal to the DSM costs per KWH by customer sector according to the following formula:

$$\text{Adjustment Factor} = \frac{DSM\ (c)}{S(c)}$$

Where DSM is the cost by customer sector of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances; (c) is customer sector; and S is the adjusted KWH sales by customer sector.

2. Demand-Side Management (DSM) costs shall be the most recent forecasted cost plus any over/under recovery balances recorded at the end of the previous period.

   a. Program costs are any costs the Company incurred associated with demand-side management which were approved by the Kentucky Power Company DSM Collaborative. Examples of costs to be included are contract services, allowances, promotion, expenses, evaluation, lease expense, etc. by customer sector.

   b. Net lost revenues are the calculated net lost revenues by customer sector resulting from the implementation of the DSM programs.

   c. Incentives are a shared-savings incentive plan consisting of one of the following elements: The efficiency incentive, which is defined as 15 percent of the estimated net savings associated with the programs. Estimated net savings are calculated based on the California Standard Practice Manual's definition of the Total Resources Cost (TRC) test, or the maximizing incentive which is defined as 5 percent of actual program expenditures if program savings cannot be measured.

   d. Over/ Under recovery balances are the total of the differences between the following:

      (i) the actual program costs incurred versus the program costs recovered through DSM adjustment clause, and

      (ii) the calculated net lost revenues realized versus the net lost revenues recovered through the DSM adjustment clause, and

      (iii) the calculated incentive to be recovered versus the incentive recovered through the DSM adjustment clause.

3. Sales (S) shall be the total ultimate KWH sales by customer sector less non-metered, opt-out and lost revenue impact KWHs by customer sector.

4. The provisions of the Demand-Side Management Adjustment Clause will be effective for the period ending December 31, 2011.

(Cont'd on Sheet No. 22-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 22-2
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 22-2

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

RATE. (Cont'd.)

5. The DSM adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

7. The resulting range for each customer sector per KWH during the three-year Experimental Demand-Side Management Plan is as follows:

		CUSTOMER SECTOR		
		RESIDENTIAL ($ Per KWH)	COMMERCIAL ($ Per KWH)	INDUSTRIAL*
Floor Factor	=	0.000614	0.000326	- 0 -
Ceiling Factor	=	0.002279	0.001645	- 0 -

8. The DSM Adjustment Clause factor ($ Per KWH) for each customer sector which fall within the range defined in Item 7 above is as follows:

	CUSTOMER SECTOR		
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL*
DSM (c)	1,681,109	651,981	- 0 -
S (c)	1,161,789,200	661,238,700	- 0 –
Adjustment Factor	$ 0.001447	$ 0.000986	- 0 –

* The Industrial Sector has been discontinued pursuant to the Commission's Order dated September 28, 1999.

PROGRAM DESCRIPTIONS.

The D.S.M.C. program availability, program, rate, and equipment descriptions follow:

(Cont'd on Sheet 22-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: TEE – Targeted Energy Efficiency

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers receiving retail electric service from the Company, who have primary electric heat and use an average of 700 kWh per month. Residential customers without primary electric heating may also be eligible for limited efficiency measures if they have electric water heating and use an average of 700 kWh from November through March. To qualify, the household's income cannot exceed the designated poverty guidelines as administered by your community action agency. The household must also qualify according to the guidelines for the Weatherization Assistance Programs administered by the communication community action agencies.

PROGRAM DESCRIPTION

The Kentucky Power Targeted Energy Efficiency Program (TEE) provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies. The program funding and service is supplemental to the Weatherization Assistance Programs offered by your community action agency. This program provides energy saving improvements to your existing home. Program services can include these items, as applicable and per program guidelines:

- Energy audit
- Air infiltration diagnostic test to find air leaks
- Air leakage sealing
- Attic, floor, side-wall insulation
- Duct sealing and insulation
- High efficiency compact fluorescent light bulbs (CFLs)
- Domestic hot water heating insulation (electric)
- Customer education on home energy efficiency
- Partial funding High efficiency heat pump (restrictions apply)

RATE

No rate applies for this program.

EQUIPMENT

The Kentucky Community Action network of not-for-profit community action agencies will furnish and install, in the customer's presence, the equipment as provided by this program.

(Cont'd on Sheet No. 22-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: MEF – Modified Energy Fitness

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers living in a single-family residence, who receive retail all-electric service from the Company and use an average of 1,000 kWh per month over the last twelve months. Customers living in site built homes and mobile homes are eligible.

PROGRAM DESCRIPTION

The Kentucky Power Modified Energy Fitness Program (MEF) provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. This program provides energy saving improvements to a customer's existing home. Program services may include these items, as applicable and per program guidelines:

- Complete energy audit with customized report
- Air infiltration diagnostic test to find air leaks
- Energy savings booklet
- Energy conservation measures installed (per program guidelines)

RATE

No rate applies for this program.

EQUIPMENT

The Company, or its authorized agents, will furnish and install, in the customer's presence, the energy conservation measures as provided by this program.

(Cont'd on Sheet No. 22-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: <u>EEFS – Energy Education for Students</u>

AVAILABILITY OF SERVICE

All schools within Kentucky Power's service territory are eligible to participate. The program targets 7th grade students.

PROGRAM DESCRIPTION

The Kentucky Power Student Energy Education Program (EEFS) targets 7th grade students at participating schools within the Kentucky Power Company service territory. The program introduces them to various aspects of responsible energy use and conservation. With this program, students use math and science skills to learn how energy is produced and used, and methods to conserve energy that can easily be applied in their own homes.

The Company partners with the National Energy Education Development Project (NEED) to implement this program. NEED is an established and respected energy education organization that has been presenting programs for teachers and students in Eastern Kentucky for many years. The program, provided at no cost to participating school systems, includes:

- Professional development for teachers where they will receive classroom curriculum and educational materials on energy, electricity, economics and the environment
- Each Student receives compact fluorescent lights (CFLs) to help students apply their classroom learning at home
- An opportunity for participating students and their families to make the ENERGY STAR® Pledge

RATE

No rate applies for this program.

EQUIPMENT

The CFLs furnished by the Company are delivered to the schools for delivery to students. The CFLs will not be installed by the Company, or its authorized agents.

(Cont'd on Sheet No. 22-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: COCFL – Community Outreach CFL

AVAILABILITY OF SERVICE

All residential retail customers of Kentucky Power are eligible for the program.

PROGRAM DESCRIPTION

Through the CFL Outreach Program, Kentucky Power distributes compact fluorescent lights (CFLs) to customers at company-sponsored community events. The program aims to educate and encourage customers to save money by using energy efficient lighting. The company sponsors community distribution events throughout the year where a package of CFLs is distributed to each qualifying residential customer. Customer energy education is also provided at these events.

RATE

No rate applies for this program.

EQUIPMENT

The CFLs furnished by the Company are delivered to the community events and provided to customers having an active electric account. The CFLs will not be installed by the Company, or its authorized agents.

(Cont'd on Sheet No. 22-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 22-7
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 22-7

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: REP - Residential Efficient Products

AVAILABILITY OF SERVICE

All Kentucky Power residential customers are eligible to participate.

PROGRAM DESCRIPTION

The Kentucky Power Residential Efficient Products Program (REP) offers residential customers instant rebates on ENERGY STAR lighting products at participating retail stores across our service territory. The program targets the purchase of lighting products through in-store promotion as well as special sales events. Customer incentives facilitate the increased purchase of high efficiency products while in-store signage, sales associate training and support makes provider participation easier.

A convenient online store where customers can shop for energy efficient lighting and get immediate discounts is also available, including specialty and hard-to-find CFLs. LED holiday lights, LED nightlights, and ENERGY STAR® ceiling fans.

RATE

Vendor controlled and adjusted in-store rebates can range from $1.00 per single pack up to $3.00 per multi pack, for up to a12-bulb limit per purchase are available while funds last.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase and install the required equipment.

(Cont'd on Sheet No. 22-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: HEHP – High Efficiency Heat Pump

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers who live in site built homes with a central electric resistance heating system or an existing less efficient heat pump system and have received retail electric service from the Company for the past twelve months at that residence.

PROGRAM DESCRIPTION

The Kentucky Power High Efficiency Heat Pump (HEHP) offers an incentive to residential customers who upgrade their central electric resistance heating system or existing less efficient heat pump system to a new, high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance Factor) for resistance heat upgrade, or 14 SEER and 8.2 HSPF for upgrading from a less efficient existing heat pump to a high efficiency heat pump unit.

RATE

A $400 incentive is offered to residential customers that qualify.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase and install the required equipment by an approved HVAC dealer participating in the program.

(Cont'd on Sheet No. 22-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: MHHP – Mobile Home High Efficiency Heat Pump

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers who live in a mobile home with a central electric resistance heating system and have received retail electric service from the Company for the past twelve months at that residence.

PROGRAM DESCRIPTION

The Kentucky Power Mobile Home High Efficiency Heat Pump (MHHP) offers an incentive to residential customers who live in a mobile home and upgrade their central electric resistance heating system with a new, high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance Factor).

RATE

A $400 incentive is offered to residential customers that qualify.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase and install the required equipment by an approved HVAC dealer participating in the program.

(Cont'd on Sheet No. 22-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: MHNC – Mobile Home New Construction

AVAILABILITY OF SERVICE

Available on a voluntary basis to individual residential customers who purchase a new mobile home built with Zone 3 insulation and a high efficiency heat pump.

PROGRAM DESCRIPTION

The Kentucky Power Mobile Home New Construction (MHNC) offers an incentive to residential customers who purchase a new mobile home having an insulation upgrade and a high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance Factor).

RATE

A $500 incentive is offered to residential customers that qualify.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase the new mobile home from a manufactured housing dealer participating in the program and who can administer an upgrade for required equipment.

(Cont'd on Sheet No. 22-11)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 22-11
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 22-11

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: Residential & Commercial HVAC Diagnostic and Tune-up

AVAILABILITY OF SERVICE

Available to Kentucky Power residential customers and small commercial customers using less than 100 kW peak demand having unitary central heat pump systems. The Kentucky Power Small Commercial HVAC Program encourages small commercial customers to keep their heating, ventilation and air conditioning (HVAC) equipment operating at peak efficiency, by way of a simple tune-up.. The program is not applicable for customers seeking repair of non-operational units.

PROGRAM DESCRIPTION – HVAC Diagnostic and Tune-up Program

The residential and commercial customer will be offered an incentive when receiving this Diagnostic and Tune-up service from a participating, state licensed contractor. It will help extend the life of the system, reduce energy costs and improve the interior comfort of your business. The diagnostic and tune-up service includes testing for inefficiencies in air conditioning and heat pump systems due to air-restricted indoor or outdoor coils and over or under refrigerant charge.

RATE

A $50 incentive is offered to residential customers and commercial customers that qualify.

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to contact a participating state licensed program dealer who can administer the diagnostic service.

(Cont'd on Sheet No. 22-12)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: Small Commercial HVAC Programs

AVAILABILITY OF SERVICE

Available to Kentucky Power commercial customers using less than 100 kW peak demand whose primary heat source is electricity. The Kentucky Power Small Commercial HVAC Program encourages small commercial customers to keep their heating, ventilation, and air conditioning (HVAC) equipment operating at peak efficiency by an equipment upgrade.

PROGRAM DESCRIPTION – High Efficiency Heat Pump/Air Conditioner Program

The commercial customer will receive financial incentives for upgrading to a new qualifying central air conditioning or heat pump system (up to a five-ton unit with a Consortium for Energy Efficiency (CEE) Tier 1 rating). The incentive helps offset the cost of the investment, and the improved efficiency can give long-term savings.

RATE

The following incentives are offered for qualifying purchases:

Air Conditioner - 36,000 Btu/h or lower	Incentive = $250
Air Conditioner - 36,000 – 65,000 Btu/h	Incentive = $400
Heat Pump - 36,000 Btu/h or lower	Incentive = $300
Heat Pump - 36,000 – 65,000 Btu/h	Incentive = $450

EQUIPMENT

No equipment required to participate in this program will be furnished or installed by the Company, or its authorized agents. It is the customer's responsibility to purchase the high efficiency heat pump or air conditioner from a participating program dealer who can administer an upgrade for required equipment.

(Cont'd on Sheet No. 22-13)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF D.S.M.C.
(DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE) (Cont'd.)

PROGRAM: CIP – Commercial Incentive Program

AVAILABILITY OF SERVICE

All commercial (non-industrial) customers in Kentucky Power's service territory are eligible to participate.

PROGRAM DESCRIPTION

The Kentucky Power Commercial Incentive Program (CIP) offers a convenient way to receive funding for common energy efficiency projects. The Commercial Incentive Program provides financial incentives to business customers who implement qualified energy-efficient improvements and technologies.

Incentives are available for a variety of energy-saving technologies in existing buildings and new construction projects. Choose from a menu of prescriptive measures with standardized incentives. The program menu includes, but is not limited to, incentives for:

- Lighting
- Heating, ventilation, and air conditioning (HVAC)
- Food Service and Refrigeration

A complete list of the eligible equipment and incentive amounts can be found in the Program Application located at KentuckyPower.com/save/programs.

RATE

The maximum payout is 50% of incremental equipment costs, up to $20,000 annually per customer account is offered to qualifying commercial customers that qualify.

The Company, or its authorized agents, will administer the evaluation of customer installed energy measures. The Company, or its authorized agents, may provide support for the installation services through approved program contractors.

AGREEMENT

A customer program application agreement is required to participate in this program.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF B.E.R.
(Biomass Energy Rider)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., ~~Experimental~~ S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S.,L.G.S.O.D., ~~O.P., C.I.P.-T.O.D.~~ *I.G.S.,* C.S.-I.R.P., M.W., O.L. and S.L. T

RATE.

1. When energy is generated and sold to the Company from the ecopower biomass facility, an additional charge equal to the product of the kWh of sales and a biomass adjustment factor (A) shall be made, where, "A", calculated to the nearest 0.0001 mil per kilowatt=hour, is defined as set forth below.

   Biomass Adjustment Factor (A)=(R*Pm)/Sm

   In the above formulas "R" is the rate for the current calendar year approved by this commission in the REPA between ecopower and Kentucky Power Company, "P" is the about of Kwh purchased by Kentucky Power in the current (m) period, and "S" is the kWh sales in the current (m) period, all defined below.

2. Rate (R) shall be the dollar per MWh as defined in the REPA between ecopower and Kentucky Power Company, including any applicable escalation factor as defined in the REPA.

3. Produced energy (P) shall be the MWh produced and sold to Kentucky Power Company.

4. Sales (S) shall be all KWh sold, excluding intersystem sales. Utility used energy shall not be excluded in the determination of sales (S).

5. Any over/under recovery will be reflected in the monthly filing for the second billing moth following the month the cost is incurred.

6. The monthly bio mass energy rider shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 23- 2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 23- 2

RESERVED FOR FUTURE USE

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 24-1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 24-1

TARIFF P.J.M.R.
(PJM RIDER)

N

APPLICABLE:

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES: *(Tariff Code 390)*

Tariff Class	*¢/kWh*	*\$/kW*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	*0.0000*	--
S.G.S. and S.G.S.-T.O.D.	*0.0000*	--
M.G.S.	*0.0000*	*0.00*
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	*0.0000*	--
L.G.S. and L.G.S.-T.O.D.	*0.0000*	*0.00*
L.G.S.-L.M.-T.O.D.	*0.0000*	*0.00*
I.G.S. and C.S.-I.R.P	*0.0000*	*0.00*
M.W.	*0.0000*	--
O.L.	*0.0000*	--
S.L.	*0.0000*	--

The kWh adjustment factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW adjustment factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS and IGS tariff classes.

The PJM Rider adjustment factor shall be modified annually to reflect the difference between the approved base level of PJM charges and credits and the PJM charges and credits actually experienced.

The PJM Rider adjustment factor shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Adjustment Factor} = \frac{PJME \times (BE_{Class} / BE_{Total}) + PJMD \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Adjustment Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Adjustment Factor} = \frac{PJME \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Adjustment Factor} = \frac{PJMD \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

N

(Cont'd on Sheet 24-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission
In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 24-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 24-2

N

PJM RIDER (Cont'd)
(P.J.M.R.)

RATES: (Cont'd)

Where:

1. *"PJMD" is the actual (over)/under recovery of annual retail PJM demand-related net costs; calculated by comparing the amount of PJM demand-related net costs in base rates to those retail PJM demand-related net costs actually incurred during the review period.*

2. *"PJME" is the actual (over)/under recovery of annual retail PJM energy-related net costs; calculated by comparing the amount of PJM energy-related net costs in base rates to those retail PJM energy-related net costs actually incurred during the review period.*

3. *"BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.*

4. *"BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.*

5. *"CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:*

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
(1)	(2)	(3)	(4)=(2)x(3)
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2		0.0236060%	
S.G.S. and S.G.S.-T.O.D.		0.0163937%	
M.G.S.		0.0177002%	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		0.0177002%	
L.G.S.and L.G.S.-T.O.D.		0.0169381%	
L.G.S.-L.M.-T.O.D.		0.0169381%	
I.G.S.and C.S.-I.R.P		0.0130626%	
M.W.		0.0134057%	
O.L.		0.0009431%	
S.L.		0.0009890%	
	BE_{Total}		CP_{Total}

6. *"BE_{Total}" is the sum of the BE_{Class} for all tariff classes.*

7. *"CP_{Total}" is the sum of the CP_{Class} for all tariff classes.*

The adjustment factor as computed above shall be further modified to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the PJM Rider adjustment revenues.

(Cont'd on Sheet 24-3)

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

P.J.M. RIDER (Cont'd)
P.J.M.R. N

The annual PJM Rider shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVE FOR FUTURE USE

~~RIDER E.C.S. - C. & E.~~ D

~~(Emergency Curtailable Service—Capacity & Energy Rider)~~

~~AVAILABILITY OF SERVICE.~~

~~This rider shall be available through May 31, 2012 for Emergency Curtailable Service (ECS) to Kentucky Power Company (KPCo or the Company) retail customers taking firm service from the Company under Tariffs MGS, MGS-TOD, LGS, LGS-TOD, QP,CIP-TOD or MW. The Company reserves the right to limit the amount of ECS capacity contracted under this Rider. The Company will take ECS requests in the order received. If ECS requests exceed the Company's needs to meet its FRR requirements, the Company will bid the remaining capacity into the PJM RPM auction if the PJM rules permit it, providing those customers the compensation available under this rider. The PJM Demand Response Program shall not be available to customers eligible for this service.~~

~~CONDITIONS OF SERVICE.~~

1. ~~The provisions of this Rider qualify under the PJM Emergency Demand Response Program as of the effective date. If the PJM Tariff is subsequently revised, the Company reserves the right to make comparable changes to this Rider in order to continue to qualify under the PJM Emergency Demand Response Program.~~

2. ~~The Company reserves the right to call for (request) customers to curtail use of the customer's ECS load when, in the sole judgment of the Company, an emergency condition exists on the American Electric Power (AEP) System or the PJM Interconnection, L.L.C. (PJM) RTO. The Company shall determine that an emergency condition exists if curtailment of load served under this Rider is necessary in order to maintain service to the Company's other firm service customers according to the AEP System Emergency Operating Plan or if PJM issues an Emergency Curtailable Service Notice.~~

3. ~~The Company will endeavor to provide as much advance notice as possible of curtailments under this Rider including an estimate of the duration of such curtailments. However, the customer's ECS load shall be curtailed within 2 hours if so requested.~~

4. ~~In no event shall the customer be subject to ECS load curtailment under the provisions of this Rider for more than 60 hours during any year or for more than 10 interruptions per year. However, a customer must agree to be subject to ECS Curtailments of up to 6-hour duration for each curtailment event, on weekdays between 12 noon to 8 pm for the months May through September and between 6 am to 10 pm for the months October through April.~~

5. ~~The Company will inform the Customer regarding the communication process of notices to curtail. The customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.~~

6. ~~No responsibility or liability of any kind shall attach to or be incurred by the company or the AEP system for, or on account of, any loss, cost, expense, or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this rider.~~

7. ~~If no Emergency events are called during the summer of the delivery year, the Company will conduct a test and verify the customer's ability to curtail as required by the PJM RTO. The Company reserves the right to re-test the customer if the Company does not achieve the minimum 80% compliance testing standards for all of the Company's ECS customers as required by PJM. These tests must be conducted for one hour during the on-peak hours from June 1 through September 30 during the delivery year.~~ D

~~(Cont'd on Sheet No. 24-2)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVE FOR FUTURE USE

~~RIDER E.C.S. - C. & E. (Cont'd)~~

~~(Emergency Curtailable Service—Capacity & Energy Rider)~~ D

~~CONDITIONS OF SERVICE (Cont.)~~

8. ~~The Company reserves the right to discontinue service to the customer under this Rider if the customer fails to curtail under any circumstances as requested by the Company.~~

~~CURTAILED DEMAND.~~

~~The customer's Curtailed Demand is determined based upon which method of measurement the customer chooses. The customer may choose one of two methods to measure the curtailed demand: 1) Guaranteed Load Drop (GLD) or 2) Firm Service Level (FSL). The method chosen shall remain in effect for an entire delivery year, June 1 through May 31 of the following year as defined by PJM.~~

~~Guaranteed Load Drop (GLD) Method~~

~~GUARANTEED LOAD DROP (GLD).~~

~~Each customer must designate a Guaranteed Load Drop, which amount shall be the minimum demand reduction that the customer will provide for each hour during a curtailment event or during a curtailment test.~~

~~CUSTOMER BASELINE LOAD CALCULATION.~~

~~A Customer Baseline Load (CBL) will be calculated for each hour corresponding to each event hour. Normally, the CBL will be calculated for each hour as the average corresponding hourly demands from the highest 4 out of the 5 most recent similar non-event days in the period preceding the relevant load reduction event. The highest load days are defined as the similar days (Weekday, Saturday, Sunday/Holiday) with the highest energy consumption spanning the event period hours. In cases where the normal calculation does not provide a reasonable representation of normal load conditions, the company and customer may develop an alternative CBL calculation that more accurately reflects the customer's normal consumption pattern.~~

~~CURTAILED ENERGY.~~

~~The Curtailed Energy shall be determined for each event hour, defined as the difference between the customer's CBL for that hour and the customer's metered load for that hour.~~

~~CURTAILMENT CREDITS.~~

~~The **Curtailment Energy Credit** shall be 80 percent of the AEP East Load Zone hourly Real-Time Locational Marginal Price (LMP) established by PJM (including congestion and marginal losses) for each event hour.~~

~~The **Curtailment Demand Credit** shall be 80 percent of the Reliability Pricing Model (RPM) auction price established by PJM in its Base Residual capacity auction for the current delivery year, expressed in $/MW-day multiplied by the GLD MWs.~~ D

~~(Cont'd on Sheet No. 24-3)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

~~RIDER E.C.S. – C. & E. (Cont'd)~~
~~(Emergency Curtailable Service – Capacity & Energy Rider)~~ D

~~MONTHLY DEMAND CREDIT.~~

~~The Monthly Demand Credit shall be equal to one-twelfth of the product of the Guaranteed Load Drop and the Curtailment Demand Credit times 365. The Monthly Demand Credit shall be applicable to each month the customer is served under this Rider, regardless of whether or not there are any curtailment events during the month.~~

~~MONTHLY EVENT CREDIT.~~

~~An Event Credit shall be calculated for each event hour equal to the product of the Curtailed Energy for that hour and the Curtailment Energy Credit for that hour. The Monthly Event Credit shall be the sum of the hourly event credits for all events occurring in the calendar month, but shall not exceed the customer's monthly energy charge under the applicable tariff. The customer shall not receive event credit for any curtailment periods to the extent that the customer's curtailable load is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions, or any event other than the customer's normal operating conditions.~~

~~NONCOMPLIANCE CHARGE.~~

~~If the customer fails to fully comply with a request for curtailment under the provisions of this Rider, then the Noncompliance Charge shall apply. If a customer does not reduce load by the full GLD, a noncompliance charge shall apply. For this purpose, Actual Load Drop (ALD) is defined as the difference between the customer's CBL (Customer Baseline Load) and their actual hourly load. If the ALD is less than the GLD, the customer will be in non-compliance.~~

~~The Noncompliance Demand Charge will be calculated based on the number of events missed because the customer did not curtail and the total number of events called by AEP to date. A penalty will be determined as the non-compliance load times the RPM auction price ($/MW-day) times 365, (e.g. curtailment of only 80 MW of a 100 MW ECS load is non-compliance and counts as a missed event, but the customer's annual payment will be reduced only for the 20 MW non-compliance load times the appropriate percentage from the table below). The penalty will then be multiplied by the percentage of reduction based upon the number of non-compliance events for the customer compared to the number of events called. Below is a table of annual payment reduction percentages.~~

~~Annual Payment Reduction Percentages for Non-compliance~~					
	~~Number of Events Called Annually~~				
~~Missed Events~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5 or more~~
~~1~~	~~100%~~	~~50%~~	~~33%~~	~~25%~~	~~20%~~
~~2~~		~~100%~~	~~67%~~	~~50%~~	~~40%~~
~~3~~			~~100%~~	~~75%~~	~~60%~~
4				~~100%~~	~~100%~~

~~If the customer misses four events, the customer will be charged 100% of the total annual payment amount. The Company and the customer will discuss methods to comply during future events, but ultimately the customer can be dismissed from the program if either party is not satisfied that the problem has been resolved. Further, the customer's service under this Rider may be discontinued pursuant to the Conditions of Service.~~ D

~~(Cont'd on Sheet No. 24-4)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

~~RIDER E.C.S. - C. & E. (Cont'd)~~
~~(Emergency Curtailable Service – Capacity & Energy Rider)~~ D

~~Firm Service Level (FSL) Method~~

~~PEAK LOAD CONTRIBUTION.~~

~~A Customer's Peak Load Contribution (PLC) will be calculated each year as the average of its load during PJM's five highest peak loads during the twelve month period ended October 31 of the previous year.~~

~~AVAILABLE CURTAILBLE DEMAND (ACD).~~

~~Each customer must designate an Available Curtailable Demand, defined as the difference between the PLC and the Firm Service Level (FSL). The FSL demand is the level to which the customer agrees to reduce load to or below for each hour during a curtailment event.~~

~~CUSTOMER BASELINE LOAD CALCULATION.~~

~~A Customer Baseline Load (CBL) will be calculated for each hour corresponding to each event hour. Normally, the CBL will be calculated for each hour as the average corresponding hourly demands from the highest 4 out of the 5 most recent similar non-event days in the period preceding the relevant load reduction event. The highest load days are defined as the similar days (Weekday, Saturday, Sunday/Holiday) with the highest energy consumption spanning the event period hours. In cases where the normal calculation does not provide a reasonable representation of normal load conditions, the company and customer may develop an alternative CBL calculation that more accurately reflects the customer's normal consumption pattern.~~

~~CURTAILED ENERGY.~~

~~The Curtailed Energy shall be determined for each event hour, defined as the difference between the customer's CBL for that hour and the customer's metered load for that hour.~~

~~CURTAILMENT CREDITS.~~

~~The Curtailment Demand Credit shall be 80 percent of the Reliability Pricing Model (RPM) auction price established by PJM in its Base Residual capacity auction for the current delivery year, expressed in $/MW-day multiplied by the Available Curtailable Demand.~~

~~MONTHLY DEMAND CREDIT.~~

~~The Monthly Demand Credit shall be equal to one-twelfth of the product of the Available Curtailable Demand and the Curtailment Demand Credit ($/MW-day) times 365. The Monthly Demand Credit shall be applicable to each month the customer is served under this Rider, regardless of whether or not there are any curtailment events during the month.~~

~~MONTHLY EVENT CREDIT.~~

~~An Event Credit shall be calculated for each event hour equal to the product of the Curtailed Energy for that hour and the Curtailment Energy Credit for that hour. The Monthly Event Credit shall be the sum of the hourly event credits for all events occurring in the calendar month, but shall not exceed the customer's monthly energy charge under the applicable tariff. The customer shall not receive event credit for any curtailment periods to the extent that the customer's curtailable load is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions, or any event other than the customer's normal operating conditions.~~ D

~~(Cont'd on Sheet No. 24-5)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 24-5
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 24- 5

~~RIDER E.C.S. - C. & E. (Cont'd)~~
~~(Emergency Curtailable Service—Capacity & Energy Rider)~~ D

~~**NONCOMPLIANCE CHARGE.**~~

~~If the customer fails to fully comply with a request for curtailment under the provisions of this Rider, then the Noncompliance Charge shall apply. If a customer is operating at or below their designated Firm Service Level during an event, it will be understood that they have no capacity available with which to comply and will not be charged a noncompliance penalty. If the metered demand during the curtailment event is above the designated FSL, the customer will be considered non-compliant. The amount of non-compliance demand is equal to the difference between the customer's metered demand and the designated FSL.~~

~~The Noncompliance Demand Charge will be calculated based on the number of events during which the customer was noncompliant and the total number of events called by AEP to date. A penalty will be determined as the amount of non-compliance load times the RPM auction price ($/MW-day) times 365, (e.g. curtailment of only 80 MW of a 100 MW ECS load is non-compliance and counts as a missed event, but the customer's annual payment will be reduced only for the 20 MW non-compliance load times the appropriate percentage from the table below). The penalty will then be multiplied by the percentage of reduction based upon the number of non-compliance events for the customer compared to the number of events called. Below is a table of annual payment reduction percentages.~~

~~**Annual Payment Reduction Percentages for Non-compliance**~~					
	~~**Number of Events Called Annually**~~				
~~**Missed Events**~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5 or more~~
~~1~~	~~**100%**~~	~~**50%**~~	~~**33%**~~	~~**25%**~~	~~**20%**~~
~~2~~		~~**100%**~~	~~**67%**~~	~~**50%**~~	~~**40%**~~
~~3~~			~~**100%**~~	~~**75%**~~	~~**60%**~~
~~4~~				~~**100%**~~	~~**100%**~~

~~If the customer misses four events, the customer will be charged 100% of their total annual payment amount, will be dismissed from the program, and may not be eligible to participate in the program until both parties are satisfied that the problem has been resolved. Further, the customer's service under this Rider may be discontinued pursuant to the Conditions of Service.~~

~~**Additional Provisions**~~

~~**CUSTOMER CREDIT.**~~

~~The monthly credit(s) will be provided to the customer by check within 60 days after the end of the month. A customer may request aggregation of individual customer accounts into a single credit.~~

~~**CUSTOMER CHARGE.**~~

~~Customers taking service under this Rider shall pay a monthly customer charge of $10.00 per account to offset the cost of the customer-related expenses for additional load determination and billing expenses. If a change in metering equipment or functionality is required, customers taking service under this Rider shall pay the additional cost of installation. The Company will make available to the customer the real time pulse metering data, if requested by the customer, for an additional fee.~~ D

~~(Cont'd on Sheet No. 24-6)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

~~RIDER E.C.S. - C. & E. (Cont'd)~~
~~(Emergency Curtailable Service – Capacity & Energy Rider)~~ D

~~TERM.~~

~~Contracts under this Rider shall be made for an initial period of one year, corresponding with the PJM planning year, and shall remain in effect until either party provides to the other at least 30 days' written notice prior to the start of the registration period as provided for in the PJM Tariff for the next planning year of its intention to discontinue service under the terms of this Rider (registration period ends March 31, 2010 for the 2010/11 delivery year). However, this rider shall only be available through May 31, 2012.~~

~~SPECIAL TERMS AND CONDITIONS.~~

~~Individual customer information, including, but not limited to, ECS Contract Capacity and Curtailment Option, shall remain confidential.~~

~~If a new peak demand is set by the customer in the hour following the curtailment, due to the customer resuming the level of activity prior to the curtailment, the customer's previous high demand will be adjusted to disregard that new peak.~~ D

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE

~~**RIDER E.P.C.S.**~~ D
~~**(Energy Price Curtailable Service Rider)**~~

~~**AVAILABILITY OF SERVICE.**~~

~~Available for Energy Price Curtailable Service (EPCS) to customers normally taking firm service under Tariffs M.G.S.,M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D.,Q.P. and C.I.P.- T.O.D. *I.G.S.* for their total capacity requirements from the Company. The Customer must have an on-peak curtailable demand not less than 100 KW and will be compensated for 100 KW curtailed under the provisions of this Rider.~~

~~**CONDITIONS OF SERVICE.**~~

1. ~~The Company reserves the right to curtail service to the Customer's EPCS load at the Company's sole discretion.~~

2. ~~The Company will endeavor to provide as much advance notice as possible of curtailments under this Rider including an estimate of the duration of such curtailments. However, the Customer's EPCS load shall be curtailed within 1 (one) hour if so requested.~~

3. ~~For purposes of this Rider, seasons are defined as follows:~~

~~Winter~~	~~December, January and February~~
~~Spring~~	~~March, April and May~~
~~Summer~~	~~June, July and August~~
~~Fall~~	~~September, October and November~~

4. ~~The Company and the Customer shall mutually agree upon the method which the Company shall use to notify the Customer of a curtailment under the provisions of this Rider. The method shall specify the means of communicating such curtailment (e.g., the Company's customer communication system, telephone, and pager) and shall designate the Customer's representatives to receive said notification. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.~~

5. ~~No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this Rider.~~

6. ~~The Company reserves the right to test and verify the Customer's ability to curtail. Such test will be limited to one curtailment per contract term. Any failure of the customer to comply with a request to curtail load will entitle the Company to call for one additional test. The Company agrees to notify the Customer as to the month in which the test will take place, and will consider avoiding tests on days, which may cause a unique hardship to the Customer's overall operation. There shall be no credits for test curtailments nor charge for failure to curtail during a test.~~

7. ~~Upon receiving a curtailment notice from the Company, the customer must respond within 45 minutes when the request is made on a day-ahead basis and within 15 minutes when a request is made for the current day if the customer intends to participate in the curtailment event. Customers who fail to respond, or respond that they will not participate in the curtailment event, will receive no payments, nor be subject to any monetary charges described elsewhere under this Rider. However, a customer's failure to respond or a response that the customer will not participate will be considered as a failure to curtail for purposes of Paragraph 8 below.~~

8. ~~The Company reserves the right to discontinue service to the Customer under this Rider if the Customer fails to curtail under any circumstances three or more times during a season as requested by the Company.~~ D

~~(Cont'd on Sheet No. 25-2)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE

~~RIDER E.P.C.S. (Cont'd)~~
~~(Energy Price Curtailable Service Rider)~~ D

~~CONDITIONS OF SERVICE, (Cont'd)~~

~~9. The Customer shall not receive credit for any curtailment periods in which the Customer's curtailable load is already down for an extended period due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, or any event other than the customer's normal operating conditions.~~

~~CURTAILMENT OPTION.~~

~~At the time the customer contracts for service under this Rider, the customer shall select one or both of the following Curtailment Notice Types:~~

~~Notice Type 1~~	~~Day-ahead Notification~~
~~Notice Type 2~~	~~Current Day Notification~~

~~At the time the customer selects one or both types of Notice Types above, the Customer shall also select one of the following Curtailment Limits for each Notice Type selected:~~

	~~Maximum Duration~~
~~Option A~~	~~2 hours~~
~~Option B~~	~~4 hours~~
~~Option C~~	~~8 hours~~

~~The Curtailment Limit is the maximum number of hours per curtailment event for which load may be curtailed under the provisions of this Rider. The Customer shall receive credit for a minimum of 2 (two) hours per curtailment event, even if the event is shorter than two hours.~~

~~The Customer shall specify the Maximum Number of Days during the season that the Customer may be requested to curtail under each Notice Type chosen. The Customer shall also specify the Minimum Price at which the customer would be willing to curtail under each Notice Type chosen. The Company, at its discretion will determine whether the Customer shall be curtailed give the Customer's specified Curtailment Options.~~

~~EPCS CONTRACT CAPACITY.~~

~~Each Customer shall have an EPCS Contract Capacity to be considered as price curtailable capacity under this Rider. The Customer shall specify the Non-EPCS Demand, which shall be the demand at or below which the Customer will remain during curtailment periods. The EPCS Contract Capacity shall be the difference between the Customer's typical on-peak demand and the Customer's specified Non-EPCS Demand. The Company shall determine the Customer's typical on-peak demand, as agreed upon by the Company and the Customer. For the purpose of this Rider, the on-peak billing period is defined as 7:00 a.m. to 11:00 p.m., local time, for all weekdays, Monday through Friday.~~

~~The Customer may modify the amount of EPCS Contract Capacity and/or the Curtailment Options no more than once prior to each season. Modifications must be received by the Company in writing no later than 30 days prior to the beginning of the season.~~

~~(Cont'd on Sheet No. 25-3)~~ D

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 25-3
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 25-3

RESERVED FOR FUTURE USE

~~**RIDER E.P.C.S. (Cont'd)**~~
~~**(Energy Price Curtailable Service Rider)**~~ D

~~**CURTAILED DEMAND.**~~

~~For each curtailment period, Curtailed Demand shall be defined as the difference between the Customer's typical on-peak demand and the maximum 15-minute integrated demand during each interval of the curtailment period.~~

~~**CURTAILMENT CREDIT.**~~

~~Hourly PCS Energy shall be defined as the sum of the Curtailed Demand for each 15-minute interval of the hour divided by four (4). The Curtailment credit shall be equal to the product of the Hourly EPCS Energy and the greater of the following: (a) 80% of the AEP East Load Zone Real-Time Locational Marginal Price (LMP) established by PJM (including congestion and marginal losses) (b) the Minimum Price as specified by the Customer or (c) 3.5 cents/kWh.~~

~~**MONTHLY CREDIT.**~~

~~The Monthly Credit shall be equal to the product of the PCS Energy and the applicable Curtailment Option Credit less any Noncompliance Charges. The Monthly Credit will be provided to the Customer by check within 30 days after the end of the month in which the curtailment occurred. This amount will be recorded in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a subaccount so that the separate identify of this cost is preserved.~~

~~**NONCOMPLIANCE CHARGES**~~

~~If the Customer responds affirmatively that it will participate in a curtailment event, and subsequently fails to fully comply with a request for curtailment under the provisions of this Rider, then the Noncompliance Demand shall be the difference between the maximum 15-minute integrated demand during each hour of the curtailment period and the Non-EPCS Demand. Noncompliance Demand shall be billed at a rate equal to the applicable Curtailment Credit for the hours during which the Customer failed to fully comply.~~

~~**TERM.**~~

~~Contracts under this Rider may be made for an initial period of one (1) season and shall remain in effect thereafter until either party provides to the other at least 30 days' written notice prior to the start of the next season of its intention to discontinue service under the terms of this Rider.~~

~~**SPECIAL TERMS AND CONDITIONS.**~~

~~Individual Customer information, including, but not limited to, EPCS Contract Capacity and Curtailment Options, shall remain confidential.~~

~~If a change in metering equipment or functionality is required, customers taking service under this Rider shall pay the additional cost of installation. The Company will make available to the customer the real time pulse metering data, if requested by the customer, for an additional fee.~~ D

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.U.G.
(Non-Utility Generator)

AVAILABILITY OF SERVICE.

This tariff is applicable to customers with generation facilities which have a total design capacity of over 1,000 kW that intends to schedule, deliver and sell the net electric output of the facility at wholesale, and who require Commissioning Power, Startup Power and/or Station Power service from the Company.

Service to any load that is electrically isolated from the Customer's generator shall be separately metered and provided in accordance with the generally available demand-metered tariff appropriate for such service to the Customer.

This tariff is not available for standby, backup, maintenance, or supplemental service for wholesale or retail loads served by customer's generator.

DEFINITIONS.

1. **Commissioning Power -** The electrical energy and capacity supplied to the customer prior to the commercial operation of the customer's generator, including initial construction and testing phases.
2. **Station Power** - The electrical energy and capacity supplied to the customer to serve the auxiliary loads at the customer's generation facilities, usually when the customer's generator is not operating. Station Power does not include Startup Power.
3. **Startup Power** - The electrical energy and capacity supplied to the customer following a planned or forced outage of the customer's generator for the purpose of returning the customer's generator to synchronous operation.

COMMISSIONING POWER SERVICE.

Customers requiring Commissioning Power shall take service under Tariff T.S. or by special agreement with the Company.

The Customer shall coordinate its construction and testing with the Company to ensure that the customer's operations do not cause any undue interference with the Company's obligations to provide service to its other customers or impose a burden on the Company's system or any system interconnected with the Company.

STATION POWER SERVICE.

Customers requiring Station Power shall take service under the generally available demand-metered tariff appropriate for the customer's Station Power requirements.

Station Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Station Power requirements that the Company is expected to supply under the generally available demand-metered tariff appropriate for the customer.

STARTUP POWER SERVICE.

Customers requiring Startup Power have the option of contracting for such service under the terms of this tariff or under the generally available demand-metered tariff appropriate for the customer's Startup Power requirements.

Startup Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Startup Power requirements that the Company is expected to supply.

Startup Duration – The Customer shall contract for a definite number of hours sufficient to meet the maximum period of time for which the Company is expected to supply Startup Power.

(Cont'd on Sheet No. 26-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.U.G. (Cont'd)
(Non-Utility Generator)

STARTUP POWER SERVICE. (cont'd)

Startup Duration – The Customer shall contract for a definite number of hours sufficient to meet the maximum period of time for which the Company is expected to supply Startup Power.

Startup Frequency – The Customer shall contract for a definite number of startup events sufficient to meet the maximum number of times per year that the Company is expected to supply Startup Power.

Other Startup Characteristics – The customer shall provide to the Company other information regarding the customer's Startup Power requirements, including, but not limited to, anticipated time-of-use and seasonal characteristics.

Notification Requirement - Whenever Startup Power is needed, the Customer shall provide advance notice to the Company.

Upon receipt of a request from the Customer for Startup Power Service under the terms of this tariff, the Company will provide the Customer a written offer containing the Notification Requirement, generation, *transmission and distribution* rates (including demand and energy charges) and related terms and conditions of service under which service will be provided by the Company. T
Such offer shall be based upon the Startup Contract Capacity, Startup Duration, Startup Frequency, and Other Startup Characteristics as specified by the customer. In no event shall the ~~generation~~ rates be less than the sum of the Tariff ~~C.I.P.-T.O.D.~~ *I.G.S.* Energy Charge, the Fuel Adjustment Clause, the System Sales clause, the Demand-Side Management Adjustment Clause, *Asset Transfer Rider, Big Sandy Retirement Rider, Big Sandy 1 Operation Rider, Purchase Power Rider, P.J.M. Rider, KY Economic Development Surcharge*, Environmental Surcharge, the Capacity Charge and *NERC Compliance and Cybersecurity Rider.* T T T T T

If the parties reach an agreement based upon the offer provided to the customer by the Company, a contract shall be executed that provides full disclosure of all rates, terms and conditions of service under this tariff, and any and all agreements related thereto.

~~**Monthly Transmission and Distribution Rates**~~ D

	~~Service Voltage~~	
	~~Subtransmission~~	~~Transmission~~
~~Tariff Code~~	~~392~~	~~393~~
~~Reservation Charge per kW~~	~~$3.65~~	~~$2.30~~

~~Reactive Demand Charge for each kiloVAR of maximum leading or lagging reactive demand in excess of 50% of the KW of monthly metered demand… $0.69 per KVAR~~ D

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

(Cont'd on Sheet No. 26-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.U.G. (Cont'd)
(Non-Utility Generator)

MONTHLY BILLING DEMAND.

The monthly billing demand in kW shall be taken each month as the highest single 15-minute integrated peak in kW as registered by a demand meter or indicator, less the Station Contract Capacity. The monthly billing demand so established shall in no event be less than the greater of (a) the Startup Contract Capacity or b) the customer's highest previously established monthly billing demand during the past 11 months.

MONTHLY BILLING ENERGY.

Interval billing energy shall be measured each 15-minute interval of the month as the total KWH registered by an energy meter or meters less the quotient of the Station Contract Capacity and four (4). In no event shall the interval billing energy be less than zero (0). Monthly billing energy shall be the sum of the interval billing energy for all intervals of the billing month.

TRANSMISSION SERVICE.

Transmission Provider – The entity providing transmission service to customers in the Company's service territory. Such entity may be the Company or a regional transmission entity.

Prior to taking service under this tariff, the Customer must have a fully executed Interconnection and Operation Agreement with the Company and/or the Transmission Provider or an unexecuted agreement filed with the Federal Energy Regulatory Commission under applicable procedures.

Should the Transmission Provider implement charges for Transmission Congestion, the Company shall provide 30 days written notice to the customer. Upon the expiration of such notice period, should the customer's use of Startup Power result in any charges for Transmission Congestion from the Transmission Provider, such charges, including any applicable taxes or assessments, shall be paid by or passed through to the customer without markup. Transmission Congestion is the condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system.

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than one year.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 kW.

SPECIAL TERMS AND CONDITIONS.

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

This tariff shall not obligate the Company to purchase or pay for any capacity or energy produced by the Customer's generator.

Customers desiring to provide Startup and Station Power from commonly owned generation facilities that are not located on the site of the customer's generator (remote self-supply), shall take service under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

AVAILIBILITY OF SERVICE.

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer-generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than thirty (30) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

METERING.

Net energy metering shall be accomplished using a standard kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

BILLING/MONTHLY CHARGES.

Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non-energy charge portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the customer shall be credited in the next billing period for the kWh difference. If time-of-day metering is used, energy flows in both directions shall be netted and accounted for at the specific time-of-use in accordance with the provisions of the customer's standard tariff and this Net Metering Service Tariff. When the customer elects to no longer take service under this Net Metering Service Tariff, any unused credit shall revert to the Company. Excess electricity credits are not transferable between customers or locations.

(Cont'd on Sheet No. 27-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

APPLICATION AND APPROVAL PROCESS.

The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

LEVEL 1 AND LEVEL 2 DEFINITIONS.

LEVEL 1

A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.

(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.

(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.

(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.

(6) The interconnection will not be on an area or spot network.

(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."

(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

(Cont'd on Sheet No. 27-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

LEVEL 1, continued

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

LEVEL 2

A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

(Cont'd on Sheet No. 27-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

LEVEL 2, continued

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

APPLICATION, INSPECTION AND PROCESSING FEES.

No application fee or other review, study, or inspection or witness test fees will be charged by the company for Level I application.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $50. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

(Cont'd on Sheet No. 27-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S. (Cont'd)
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION.

To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(Cont'd on Sheet No. 27-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION, continued

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(Cont'd on Sheet No. 27-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR INTERCONNECTION, continued

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-8)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERM OF CONTRACT.

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

(Cont'd on Sheet No. 27-9)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 30 kW generation capacity and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

~~Terry Hemsworth~~ D.G. Coordinator **(Contact person listed is subject to change.** T
American Electric Power **Please visit our website for up-to-date**
1 Riverside Plaza **information http://www.kentuckypower.com)**
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
~~themsworth@aep.com~~ dgcoordinator@aep.com T

Applicant

Name: ______________________________

Mailing Address: ______________________________

City: ______________ State: __________ Zip: __________

Phone: (____) ______________ Phone: (____) ______________

E-mail address: ______________________________

Service Location

Street Address: ______________________________

City: ______________ State: __________ Zip: __________

Electric Service Account Number: ______________________________

Alternate Contacts

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Name	Company	Telephone/Email

(Cont'd on Sheet No. 27-10)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: ______________________ Model: ________________________________

Inverter Power Rating: ______________________ Voltage Rating: __________________________

Power Rating of Energy Source (i.e., solar panels, wind turbine): _____________________________

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating: ________________________________

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

(Cont'd on Sheet No. 27-11)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1:

1 Kentucky Power Company (Company) shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(Cont'd on Sheet No. 27-12)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

(Cont'd on Sheet No. 27-13)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-14)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: ________________________________ **Date:** ________________

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.

Call: ____________________ to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

____

Approved by: ________________________________ **Date:** ________________

Printed Name: ________________________________ **Title:** ________________

(Cont'd on Sheet No. 27-15)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 30kW generation).

Submit this Application (along with the application fee of $100) to:

~~Terry Hemsworth~~ DG Coordinator T
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
~~tlhemsworth@aep.com~~ dgcoordinator T

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com)

Applicant

Name: ______________________________

Mailing Address: ______________________________

City: ______________________ State: __________ Zip: __________

Project Contact Person: ______________________________

Phone: (___) ______________________ Phone: (___) ______________________

E-mail Address: ______________________________

Service Location

Street Address: ______________________________

City: ______________________ State: __________ Zip: __________

Electric Service Account Number: ______________________________

Alternate Contacts

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Name	Company	Telephone/Email

(Cont'd on Sheet No. 27-16)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

APPPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility: ____________________________

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

(Cont'd on Sheet No. 27-17)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this _____ day of ___________, 20___, by and between Kentucky Power Company (Company), and ________________________________ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: ____

Generator Size and Type: ____

Now, Therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

(Cont'd on Sheet No. 27-18)

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1 Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(Cont'd on Sheet No. 27-19)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6 Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(Cont'd on Sheet No. 27-20)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity is allowed without approval.

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 27-21)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF N.M.S.
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature: ______________________________ **Date:** ____________________

Printed Name: ______________________________ **Title:** ____________________

Company Signature: ______________________________ **Date:** ____________________

Printed Name: ______________________________ **Title:** ____________________

(Cont'd on Sheet No. 27-22)

TARIFF N.M.S.
(Net Metering Service)

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.
- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.
- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 28-1
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 28-1

TARIFF C.C.
(Capacity Charge)

AVAILABILITY OF SERVICE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., ~~Experimental~~ S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S.,L.G.S.-T.O.D., ~~Q.P., C.I.P.-T.O.D.~~ *I.G.S.* C.S.-I.R.P., M.W., O.L. and S.L. T T

RATE.

	Service Tariff	
	All Other	~~C.I.P.-T.O.D.~~ *I.G.S.*
Energy Charge per KWH per month	$ ~~0.000970~~ *0.001182*	$ ~~0.000667~~ *0.000659*

T
I R

RATE CALCULATION.

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2004-00420 and the Settlement and Stipulation Agreement dated October 20, 2004 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the supplemental annual payments tied to the 18-year extension of the Rockport Unit Power Service Agreement (UPSA). Kentucky Power will apply surcharges designed to enable recovery from each tariff class of customers, an annual supplemental payment of $5.1 million annually in Years 2005 through 2009, and then increases to $6.2 million annually in Years 2010 through 2021, and then decreases to $5,792,329 in Year 2022.

2. Kentucky Power will be entitled to receive these annual supplemental payments in addition to the base retail rates established by the Commission. The costs associated with the underlying Rockport Unit 1 and 2 UPSA will continue to be included in base rates.

3. The increased annual revenues will be generated by two different KWH rates, one for ~~CIP-TOD~~ *I.G.S.* tariff customers and one for All Other tariff customers. T

4. The allocation of the additional revenues to be collected from the ~~CIP-TOD~~ *I.G.S.* tariff customers and All Other tariff customers will be based upon the total annual revenue of each of the two-customer classes. Once the additional revenues have been allocated between the two customer classes based upon total annual Kentucky retail revenue, the additional revenue will be collected within the two customer classes (~~CIP-TOD~~ I.G.S. and All Other tariffs) on a KWH basis. The KWH rate to be applied to each of these two customer class groups shall be sufficient to generate that portion of the total increase in annual revenues equal to the percentage of total annual revenues produced by each of the two customer class groups (~~CIP-TOD~~ *I.G.S.* and All Other tariffs). T T T

5. The Stipulation and Settlement Agreement is made upon the express agreement by the Parties that the receipt by Kentucky Power of the additional revenues called for by Section III(1)(a) and III(1)(b) shall be accorded the ratemaking treatment set out in Section III. In any proceeding affecting the rates of Kentucky Power during the extension of the UPSA under this Stipulation and Settlement Agreement, the provisions of Section III are an express exception to Section VI(4) of the Stipulation and Settlement Agreement.

6. The Capacity Charge factors will be applied to bills monthly and will be shown on the Customer's bill as a separate line item.

(Cont'd on Sheet No. 28-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 28-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 28-2

TARIFF C.C.
(Capacity Charge) Cont'd

RATE CALCULATION. (Cont'd) N

7. *The capacity charge will be adjusted annually to recover amounts authorized by the Commission.*

The annual adjustment shall be determined as follows:

A. *Calculate the revenue over / under collection for the previous 12 month period, REVbilled – REVsettlement = REVdiff*

B. *Calculate the revenue requirement for the upcoming 12 month period, REVsettlement + REVdiff = REVauthorized*

C. *Calculate Capacity Charge Rates for the upcoming 12 month period,*

$$\text{IGS Capacity Charge} = \frac{\text{REVauthorized x (REVIGS / REVTotal)}}{\text{kWhIGS}}$$

$$\text{All Other Capacity Charge} = \frac{\text{REVauthorized x (REVAll Other / REVTotal)}}{\text{kWhAll Other}}$$

Where:

"REVTotal" is the total revenue billed during the most recently available 12 month period.

"REVIGS" is the total IGS customer class revenue billed during the most recently available 12 month period.

"REVAll Other" is the revenue billed from all other customer classes during the most recently available 12 month period.

"kWhIGS" is the IGS customer class total kWh billed during the most recently available 12 month period.

"kWhAll Other" is the total kWh billed to all customer classes other than IGS during the most recently available 12 month period.

"REVbilled" is the total capacity charge revenue billed during the most recently available 12 month period.

"REVsettlement" is the $6.2 million amount authorized to be billed during the 12 month period.

"REVdiff" is the difference between capacity charge revenues billed and what the Company is authorized to collect in a 12 month period.

"REVauthorized" is the capacity charge amount to be billed over the upcoming 12 month period.

8. *The annual Capacity Charge Adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.*

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-1
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 29-1

TARIFF E.S.
(Environmental Surcharge)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., ~~Experimental~~ S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ~~Q.P., C.I.P.-T.O.D.~~, *I.G.S.,* C.S.- I.R.P., M.W., O.L., and S.L. T T

RATE.

~~In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Monthly Environmental Surcharge Factor will be fixed and maintained at 0.00% until new base rates are first established by Commission after the effective date of this tariff without regard to the calculation of the Monthly Environmental Surcharge Factor under paragraphs 1 through 4 below. Also, t~~ D D

The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph ~~3~~ 2 below and in the current period as provided in Paragraph 3 below. N N

The retail share of the revenue requirement will ~~then~~ be allocated between residential and non-residential retail customers based upon their respective total revenues *during the previous calendar year.* The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers. ~~when new base rates are established.~~ N T

~~1. The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 3 below and in the current period according to the following formula:~~ D

~~Monthly Environmental Surcharge Factor = Net KY Retail E(m) / KY Retail R(m)~~

~~Where:~~

Net ~~KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.~~

~~(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)~~

~~KY Retail R(m) = Kentucky Retail Revenues for the Expense Month.~~ D

1. ~~2.~~ Monthly Environmental Surcharge Gross Revenue Requirement, E(m) T

Where:	E(m)	=	CRR - BRR
	CRR	=	Current Period Revenue Requirement for the Expense Month.
	BRR	=	Base Period Revenue Requirement.

(Continued on Sheet 29-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 2, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-2**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 29-2

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

2.~~3.~~ Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month	Base Net Environmental Costs		
JANUARY	$ ~~3,991,163~~	*$ 2,750,919*	R
FEBRUARY	~~3,590,810~~	*$ 2,738,884*	R
MARCH	~~3,651,374~~	*$ 2,851,531*	R
APRIL	~~3,647,040~~	*$ 2,909,965*	R
MAY	~~3,922,590~~	*$ 2,897,250*	R
JUNE	~~3,627,274~~	*$ 2,835,973*	R
JULY	~~3,805,325~~	*$ 3,567,407*	R
AUGUST	~~4,088,830~~	*$ 3,319,549*	R
SEPTEMBER	~~3,740,010~~	*$ 3,378,515*	R
OCTOBER	~~3,260,302~~	*$ 3,097,929*	R
NOVEMBER	~~2,786,040~~	*$ 2,994,579*	I
DECEMBER	~~4,074,321~~	*$ 2,996,160*	R
	~~$ 44,185,079~~	*$ 36,338,660*	R

In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Mitchell FGD and all related associated costs are not included in base rates or the Base Revenue Requirement but will be included in the Current Period Revenue Requirement. The Mitchell FGD will be excluded from Base Rates at least until June 30, 2020. N

3.~~4.~~ Current Period Revenue Requirement, CRR T

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} + [((RB_{IM(c)})\,(ROR_{IM(c)})/12) + OE_{IM(c)}]\,(.15) - AS]$$

Where:

$RB_{KP(C)}$ = Environmental Compliance Rate Base for ~~Big Sandy~~. *Mitchell.* T

$ROR_{KP(C)}$ = Annual Rate of Return on ~~Big Sandy~~ *Mitchell* Rate Base; T
Annual Rate divided by 12 to restate to a Monthly Rate of Return.

(Cont'd on Sheet 29-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

$OE_{KP(C)}$ = Monthly Pollution Control Operating Expenses for ~~Big Sandy~~. *Mitchell.* T

$RB_{IM(C)}$ = Environmental Compliance Rate Base for Rockport.

$ROR_{IM(C)}$ = Annual Rate of Return on Rockport Rate Base;
Annual Rate divided by 12 to restate to a Monthly Rate of Return.

$OE_{IM(C)}$ = Monthly Pollution Control Operating Expenses for Rockport.

AS = Net proceeds from the sale of *Title IV and CSAPR* SO_2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. ~~The SO_2 allowance sales can be from either EPA Auctions or the AEP Interim Allowance Agreement Allocations.~~ T T

"KP(C)" identifies components from ~~the Big Sandy~~ *Mitchell* Units – Current Period, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period. T

The Rate Base for both Kentucky Power and Rockport should reflect the current costs associated with the 1997 Plan, ~~and~~ *the* 2003 Plan, *the 2005 Plan, the 2007 Plan and the 2014 Plan.* The Rate Base for Kentucky Power should also include a cash working capital allowance based on the 1/8 formula approach, due to the inclusion of Kentucky Power's accounts receivable financing in the capital structure and weighted average cost of capital. The Operating Expenses for both Kentucky Power and Rockport should reflect the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan,~~-and~~ the 2007 Plan, *and the 2014 Plan.* T T

The Rate of Return for Kentucky Power is ~~10.50%~~ *10.62%* rate of return on equity as authorized by the Commission in its ~~June 29, 2010~~ Order *Dated XXXXXXXXX* in Case No. *2014-00396* ~~2009-00459 at page 6~~. T T

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

(Cont'd on Sheet No. 29-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

N

4. *Revenue Allocation*

$$\text{Residential Allocation } RA(m) = \frac{\text{KY Residential Retail Revenue } RR(b)}{\text{KY Retail Revenue } R(b)}$$

$$\text{All Other Allocation } OA(m) = \frac{\text{KY All Other Classes Retail Revenue } OR(b)}{\text{KY Retail Revenue } R(b)}$$

Where:
(m) = the expense month
(b) = most recent calendar year revenues

5. *Environmental Surcharge Factor*

$$\text{Residential Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail } E(m) \ * \ RA(m)}{\text{KY } RR(m)}$$

$$\text{All Other Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail } E(m) \ * \ AO(m)}{\text{KY } OR(m) - \text{KY } OF(m)}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non -Physical Revenues.)

RR(m) = Kentucky Residential Retail Revenues for the Expense Month.

OR(m) = Kentucky All Other Classes Retail Revenues for the Expense Month

OF(m) = Kentucky All Other Classes Fuel Revenues for the Expense Month N

(Cont'd on Sheet No. 29-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-5**
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 29-5

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

6.~~5.~~ Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows: T

Total Company:

~~(a) costs associated with Continuous Emission Monitors (CEMS)~~ D

~~(b) costs associated with the terms of the Rockport Unit Power Agreement~~ D

~~(c) the Company's share of the pool capacity costs associated with Gavin scrubber(s)~~ D

- return on *Title IV and CASPR* SO_2 allowance inventory T

~~(d) costs associated with air emission fees *at Rockport and Mitchell*~~ D

- ~~(b)~~ over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge T

- ~~(c)~~ costs associated with any Commission's consultant approved by the Commission T

~~(h) cost associated with Low Nitrogen Oxide (NOx) burners at the Big Sandy Generating Plant~~ D

- ~~(d)~~ costs associated with the consumption *Title IV and CSAPR* of SO_2 allowances T

- ~~costs associated with the Selective Catalytic Reduction (SCR) at the Big Sandy Generating Plant~~ D

~~(i) costs associated with the upgrade of the precipitator at the Big Sandy Generating Plant~~ D

~~(j) costs associated with the over-fire air with water injection at the Big Sandy Generating Plant~~ D

- ~~(e)~~ costs associated with the consumption of NO_x allowances T

- ~~(f)~~ return on NO_x allowance inventory T

~~(k) 25% of the costs associated with the Reverse Osmosis Water System (the amount is subject to adjustment at *subsequent 6 month surcharge reviews based on the documented utilization of* of the RO Water System by the SCR)~~ D

- ~~(g)~~ costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor) T

- Costs associated with consumables used in conjunction with approved environmental projets.

(Cont'd on Sheet No. 29-6)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2014

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 DATED XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 29-6**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 29-6

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

The Company's share of costs associated with the following environmental equipment at the Rockport Plant: N

- *Continuous Emissions Monitors*
- *Air Emission Fees*
- *Costs Associated with the Rockport Unit Power Agreement*
- *Activated Carbon Injection*
- *Mercury Monitoring*
- *Precipitator Modifications*
- *Dry Sorbent Injection*
- *Coal Combustion Waste Landfill*
- *Low NOx burners, over-fire air, Landfill*

The Company's share of costs associated with the following environmental equipment at the Mitchell Plant: N

~~(I) the Company's share of the pool capacity costs associated with the following:~~ D

- ~~Amos Unit No. 3 CEMS, Low~~ $\cancel{NO_x}$ ~~Burners, SCR, FGD, Landfill, Coal Blending Facilities and~~ $\cancel{SO_3}$ ~~Mitigation~~ D
- ~~Cardinal Unit No 1 CEMS, Low~~ $\cancel{NO_x}$ ~~Burners, SCR, Catalyst Replacement, FGD, Landfill and~~ $\cancel{SO_3}$ ~~Mitigation~~ D
- ~~Gavin Plant SCR and SCR Catalyst Replacement~~ D
- ~~Gavin Unit No 1 and 2 Low~~ $\cancel{NO_x}$ ~~Burners and~~ $\cancel{SO_3}$ ~~Mitigation~~ D
- ~~Kammer Unit Nos 1, 2 and 3 CEMS, Over Fire Air and Duct Modification~~ D
- Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners, Low NO_x burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities

- *Air Emission Fees* N
- *Precipitator Modifications and Upgrades*
- *Coal Combustion Waste Landfill*
- *Bottom Ash and Fly Ash Handling*
- *Mercury Monitoring (MATS)*
- *Dry Fly Ash Handling Conversion* N

(Cont'd on Sheet No. 29-7)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.S. (Cont'd)
(Environmental Surcharge)

RATE (Cont'd)

- ~~Muskingum River Unit No 1 Low NO_x Ductwork, Over Fire Air , Over Fire Air Modification, Water Injection and Water Injection Modification~~ D
- ~~Muskingum River Unit No 2 Low NO_x Ductwork, Over Fire Air, Over Fire Air Modification and Water Injection~~
- ~~Muskingum River Unit No 3 Over Fire Air, Over Fire Air Modification with NO_x Instrumentation~~
- ~~Muskingum River Unit No 4 Over Fire Air with Modification~~
- ~~Muskingum River Unit No 5 Low NO_x Burner with Modification and Weld Overlay, an SCR and SO3 Mitigation~~
- ~~Muskingum River Common CEMS~~
- ~~Phillip Sporn Unit No 2 Low NO_x Burners with Modifications~~
- ~~Phillip Sporn Unit No 4 and 5 Low NO_x Burners and Modulating Injection Air system with Modifications~~
- ~~Phillip Sporn Common CEMS, SO_3 Injection System and Landfill~~
- ~~Rockport Unit No 1 and 2 Low NO_x Burners and Landfill~~
- ~~Tanners Creek Unit No 1 Low NO_x Burners, with Modifications and Low NO_x Burners Leg Replacement~~
- ~~Tanners Creek Unit No 2 and 3 Low NO_x Burners with Modifications~~
- ~~Tanners Creek Unit No 4 Over Fire Air, Low NO_x Burners and ESP Controls Upgrade~~
- ~~Tanners Creek Common CEMS and Coal Blending Facilities~~
- ~~Title V Air Emission Fees at Amos, Cardinal, Gavin, Kammer, Mitchell, Muskingum River, Philip Sporn, Rockport and Tanners Creek plants.~~ D

7. ~~6.~~ The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission. T

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RESERVED FOR FUTURE USE

~~**TARIFF R.T.P.**~~
~~**(Experimental Real-Time Pricing Tariff)**~~

D

~~**AVAILABILITY OF SERVICE.**~~ ~~**TARIFF CODES**~~

~~Q.P. Tariff~~	~~CIP-TOD Tariff~~
~~366 Secondary~~	~~377 Primary~~
~~367 Primary~~	~~378 Sub-transmission~~
~~368 Sub transmission~~	~~379 Transmission~~
~~369 Transmissions~~	

~~Available for Real-Time Pricing (RTP) service, on an experimental basis, to customers normally taking firm service under Tariffs Q.P. or C.I.P.-T.O.D. for their total capacity requirements from the Company. The customer will pay real-time prices for load in excess of an amount designated by the customer. This experimental tariff will be limited to a maximum of 10 customers. The incremental cost of any special metering or communications equipment required for service under this experimental tariff beyond that normally provided under the applicable standard Q.P. or C.I.P.-T.O.D. tariff shall be borne by the customer. The Company reserves the right to terminate this Tariff at any time after the end of the experiment.~~

~~**PROGRAM DESCRIPTION.**~~

~~The Experimental Real-Time Pricing Tariff is voluntary and will be offered on a pilot basis for a three-year period. The RTP Tariff will offer customers the opportunity to manage their electric costs by shifting load from higher cost to lower cost pricing periods or by adding new load during lower price periods. The experimental pilot will also offer the customer the ability to experiment in the wholesale electricity market by designating a portion of the customer's load subject to standard tariff rates with the remainder of the load subject to real-time prices. The designated portion of the customer's load is billed under the Company's standard Q.P. or C.I.P.-T.O.D. tariff. The remainder of the customer's capacity and energy load is billed at prices established in the PJM Interconnection, L.L.C. (PJM) RTO market.~~

~~**CONDITIONS OF SERVICE.**~~

~~The customer must have a demand of not less than 1 MW and specify at least 100 kW as being subject to this Tariff. The customer designates the maximum amount of load to be supplied by Kentucky Power Company under the applicable Tariff Q.P. or Tariff C.I.P. - T.O.D. All usage equal to or less than the customer-designated level of load will be billed under the appropriate Tariff Q.P. or Tariff C.I.P. - T.O.D. All usage in excess of the customer-designated level will be billed under Tariff RTP. All reactive demand shall be billed in accordance with the appropriate Tariff Q.P. or Tariff C.I.P. - T.O.D.~~

~~**RATE.**~~

~~1. Capacity Charge.~~

~~The Capacity Charge, stated in $/kW, will be determined from the auction price set in the Reliability Pricing Model (RPM) auction held by PJM for each PJM planning year. The auction price will be adjusted by the class average diversity factor (DF) derived from billing demands for the preceding year and the 5 highest coincident peaks established for the class at the time of the 5 highest PJM hourly values. The price will be further adjusted for demand losses (DL) and a factor to reflect the PJM-required reserve margin (RM).~~

~~Capacity Charge = RPM x DF x DL x RM~~

~~Where:~~
~~RPM =Results of the annual RPM auction price applicable to the AEP load zone = $5.301/kW-month~~
~~DF = Diversity Factor~~
~~C.I.P. – T.O.D. = $0.83~~
~~Q.P. = $0.64~~
~~DL = Demand Loss Factor~~
~~RM = Reserve Margin = RPM clearing price reserve margin = 1.209~~

D

~~(Cont'd on Sheet No. 30-2)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 30-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 30-2

RESERVED FOR FUTURE USE

~~TARIFF R.T.P.~~ D
~~(Experimental Real-Time Pricing Tariff)~~

~~RATE (continued).~~

~~2. Energy Charge.~~

~~The Energy Charge, stated in $/KWH, will be determined hourly using the AEP East Load Zone Real-Time Locational Marginal Price (LMP) established by PJM (including marginal losses), adjusted for energy losses (EL). The charge will be applied to the usage in excess of the customer designated level for each billing period.~~

~~Energy Charge = LMP x EL~~

~~Where:~~
~~LMP = AEP East Load Zone Real-Time Locational Marginal Price~~
~~EL = Energy Loss Factor excluding marginal losses for transmission and subtransmission~~

~~3. Transmission Charge.~~

~~The Transmission Charge, stated in $/kW, will be determined from the Network Integration Transmission Service (NITS) rate for the AEP East Zone. The NITS rate will be adjusted by the class average diversity factor (DF) derived from billing demands for the preceding year and the coincident peak established for the class at the time of the highest AEP East Zone hourly value. The price will be further adjusted for demand losses (DL).~~

~~Transmission Charge = NITS x DF x DL~~

~~Where:~~
~~NITS = NITS Rate for the AEP East Zone = $ 2.2859/kW~~
~~DF = Diversity Factor~~
~~C.I.P. - T.O.D. = 0.83~~
~~Q.P. = 0.57~~
~~DL = Demand Loss Factor~~

~~4. Other Market Services Charge.~~

~~The Other Market Services Charge, stated in $/KWH is developed using all other PJM related market costs allocated to Kentucky Power Company from PJM not captured elsewhere. It is applied to all usage in excess of the customer designated level for each billing period.~~

~~Secondary = $0.003801/KWH~~
~~Primary = $0.003656/KWH~~
~~Subtransmission = $0.003588/KWH~~
~~Transmission = $0.003554/KWH~~

~~5. Distribution Charge.~~

~~The Distribution Charge, stated in $/kW, is equivalent to the distribution portion of the current rates included in Tariff Q.P. and Tariff C.I.P. - T.O.D.~~

~~Secondary = $7.39/kW~~
~~Primary = $4.34/Kw~~ ~~(Cont'd on Sheet No. 30-3)~~ D

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 30-3
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 30-3

RESERVED FOR FUTURE USE

~~TARIFF R.T.P.~~ D
~~(Experimental Real-Time Pricing Tariff)~~

~~RATE (continued).~~

~~6. Program Charge.~~

~~The Program Charge is $150 per month for billing, administration and communications required to implement and administer the Experimental Real-Time Pricing Tariff.~~

~~7. Riders.~~

~~Bills rendered under this Tariff for RTP usage shall be subject to any current or future non-generation related riders.~~

~~A customer's total bill shall equal the sum of the RTP bill for all usage in excess of the customer-designated level and the standard tariff bill for usage equal to or below the designated level.~~

~~DELAYED PAYMENT CHARGE.~~

~~This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.~~

~~METERED VOLTAGE.~~

~~The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered kWh and kW values will be adjusted for billing purposes. If the Company elects to adjust kWh and kW based on multipliers, the adjustment shall be in accordance with the following:~~

~~(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.~~
~~(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.~~

~~MONTHLY BILLING DEMAND.~~

~~Billing demand in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered during the month by a demand meter. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity set forth on the contract for electric service or (b) the customer's highest previously established monthly billing demand during the past 11 months. The RTP monthly billing demand shall be the customer's monthly billing demand in excess of the customer-designated level.~~

~~TERM.~~

~~Customers who participate in this experimental tariff are required to enter into a written service agreement. Customer participation will coincide with the PJM planning year which runs from June 1 through May 31. Customers must enroll by May 15 of each year to begin service on June 1 and must stay with the service for the entire planning year. Customers who choose not to re-enroll in the program are ineligible to return to the program. No additional customers will be placed under this tariff after June 1, 2010.~~ D

~~(Cont'd on Sheet No. 30-4)~~

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 30-4**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 30-4

RESERVED FOR FUTURE USE

~~TARIFF R.T.P.~~ D
~~(Experimental Real-Time Pricing Tariff)~~

~~TRANSFORMER AND LINE LOSSES.~~

~~Demand losses will be applied to the Capacity and Transmission Charges using the following factors:~~

~~Secondary = 1.10221~~
~~Primary = 1.06570~~
~~Subtransmission = 1.04278~~
~~Transmission = 1.03211~~

~~Energy losses will be applied to the Energy Charge using the following factors:~~

~~Secondary = 1.06938~~
~~Primary = 1.02972~~
~~Subtransmission = 1.00954~~
~~Transmission = 1.00577~~

~~SPECIAL TERMS AND CONDITIONS.~~

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

~~A customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by customer. When the size of the customer's load necessitates the delivery of energy to the customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the customer's system irrespective of contrary provisions in Terms and Conditions of Service.~~

~~Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.~~ D

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER G.P.O.
(Green Pricing Option Rider)

AVAILABILITY OF SERVICE.

Available to customers taking metered service under the Company's R.S., R.S.-L.M.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., ~~Experimental~~ S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ~~Q.P., C.I.P.-T.O.D.,~~ *I.G.S.,* C.S.-I.R.P. and M.W. tariffs. T

Participation in this program may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants.

CONDITIONS OF SERVICE.

Customers who wish to support the generation of electricity by Renewable Resources may contract to purchase each month a specific number of fixed kWh blocks, where each block equals 100 kWh. Customers may elect to purchase a minimum of one (1) block per month and a maximum of 500 blocks per month.

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. Only Renewable Resources brought into service on or after January 1, 1997 shall qualify.

RATE.

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for each fixed kWh block under contract regardless of the customer's actual energy consumption during that month. The charge will be applied to the customer's bill as a separate line item.

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

Charge ($ per 100 kWh block): $ 2.00/month

TERM.

This is a voluntary program. Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable.

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Green Pricing Option Rider will be used solely to purchase RECs for the program.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER A.F.S.
(Alternate Feed Service Rider)

AVAILABILITY OF SERVICE.

Standard Alternate Feed Service (AFS) is a premium service providing a redundant distribution service provided through a redundant distribution line and distribution station transformer, with automatic or manual switch-over and recovery, which provides increased reliability for distribution service. Rider AFS applies to those customers requesting new or upgraded AFS after the effective date of this rider. Rider AFS also applies to existing customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service.

Rider AFS is available to customers who request a primary voltage alternate feed and who normally take service under Tariffs M.G.S., M.G.S. TOD, L.G.S., L.G.S.-TOD, ~~Q.P., C.I.P. TOD~~ *I.G.S.*, or M.W. for their basic service requirements, provided that the Company has adequate capacity in existing distribution facilities, as determined by the Company, or if changes can be made to make capacity available. AFS provided under this rider may not be available at all times, including emergency situations. T

SYSTEM IMPACT STUDY CHARGE.

The Company shall charge the customer for the actual cost incurred by the Company to conduct a system impact study for each site reviewed. The study will consist of, but is not limited to, the following: (1) identification of customer load requirements, (2) identification of the potential facilities needed to provide the AFS, (3) determination of the impact of AFS loading on all electrical facilities under review, (4) evaluation of the impact of the AFS on system protection and coordination issues including the review of the transfer switch, (5) evaluation of the impact of the AFS request on system reliability indices and power quality, (6) development of cost estimates for any required system improvements or enhancements required by the AFS, and (7) documentation of the results of the study. The Company will provide to the customer an estimate of charges for this study.

EQUIPMENT AND INSTALLATION CHARGE.

The customer shall pay, in advance of construction, a nonrefundable amount for all equipment and installation costs for all dedicated and/or local facilities provided by the Company required to furnish either a new or upgraded AFS. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. The customer will not acquire any title in said facilities by reason of such payment. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, the following: (1) all costs associated with the AFS dedicated and/or local facilities provided by the Company and (2) any costs or modifications to the customer's basic service facilities.

The customer is responsible for all costs associated with providing and maintaining phone service for use with metering to notify the Company of a transfer of service to the AFS or return to basic service.

TRANSFER SWITCH PROVISION.

In the event the customer receives basic service at primary voltage, the customer shall install, own, maintain, test, inspect, operate and replace the transfer switch. Customer-owned switches are required to be at primary voltage and must meet the Company's engineering, operational and maintenance specifications. The Company reserves the right to inspect the customer-owned switches periodically and to disconnect the AFS for adverse impacts on reliability or safety.

(Cont'd on Sheet No. 32-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER A.F.S.
(Alternate Feed Service Rider)

TRANSFER SWITCH PROVISION (CONTINUED).

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer shall pay a monthly rate of ~~$13.57~~ *$14.25* for the Company to annually test the transfer switch / control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module. I

In the event a customer receives basic service at secondary voltage and requests AFS, the Company will provide the AFS at primary voltage. The Company will install, own, maintain, test, inspect and operate the transfer switch and control module. The customer shall pay the Company a nonrefundable amount for all costs associated with the transfer switch installation. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer is required to pay the monthly rate for testing and ongoing maintenance costs defined above. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes.

After a transfer of service to the AFS, a customer utilizing a manual or semi-automatic transfer switch shall return to the basic service within one (1) week or as mutually agreed to by the Company and customer. In the event system constraints require a transfer to be expedited, the Company will endeavor to provide as much advance notice as possible to the customer. However, the customer shall accomplish the transfer back to the basic service within ten minutes if notified by the Company of system constraints. In the event the customer fails to return to basic service within 12 hours, or as mutually agreed to by the Company and customer, or within ten minutes of notification of system constraints, the Company reserves the right to immediately disconnect the customer's load from the AFS source. If the customer does not return to the basic service as agreed to, or as requested by the Company, the Company may also provide 30 days' notice to terminate the AFS agreement with the customer.

The customer shall make a request to the Company for approval three days in advance for any planned switching.

MONTHLY AFS CAPACITY RESERVATION DEMAND CHARGE.

Monthly AFS charges will be in addition to all monthly basic service charges paid by the customer under the applicable tariff.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is ~~$4.34~~ *$6.25* per kW. I

AFS CAPACITY RESERVATION.

The customer shall reserve a specific amount of AFS capacity equal to, or less than, the customer's normal maximum requirements, but in no event shall the customer's AFS capacity reservation under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

(Cont'd on Sheet No. 32-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER A.F.S.
(Alternate Feed Service Rider)

AFS CAPACITY RESERVATION (continued).

If the customer plans to increase the AFS demand at anytime in the future, the customer shall promptly notify the Company of such additional demand requirements. The customer's AFS capacity reservation and billing will be adjusted accordingly. The customer will pay the Company the actual costs of any and all additional dedicated and/or local facilities required to provide AFS in advance of construction and pursuant to an AFS construction agreement. If customer exceeds the agreed upon AFS capacity reservation, the Company reserves the right to disconnect the AFS. If the customer's AFS metered demand exceeds the agreed upon AFS capacity reservation, which jeopardizes company facilities or the electrical service to other customers, the Company reserves the right to disconnect the AFS immediately. If the Company agrees to allow the customer to continue AFS, the customer will be required to sign a new AFS agreement reflecting the new AFS capacity reservation. In addition, the customer will promptly notify AEP regarding any reduction in the AFS capacity reservation.

The customer may reserve partial-load AFS capacity, which shall be less than the customer's full requirements for basic service subject to the conditions in this provision. Prior to the customer receiving partial-load AFS capacity, the customer shall be required to demonstrate or provide evidence to the Company that they have installed demand-controlling equipment that is capable of curtailing load when a switch has been made from the basic service to the AFS. The Company reserves the right to test and verify the customer's ability to curtail load to meet the agreed upon partial-load AFS capacity reservation.

DETERMINATION OF BILLING DEMAND.

Full-Load Requirement:

For customers requesting AFS equal to their load requirement for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly billing demand on the AFS during the past 11 months, or (c) the customer's basic service capacity reservation, or (d) the customer's highest previously established monthly billing demand on the basic service during the past 11 months.

Partial-Load Requirement:

For customers requesting partial-load AFS capacity reservation that is less than the customer's full requirements for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak on the AFS as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly metered demand on the partial-load AFS during the past 11 months.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

(Cont'd on Sheet No. 32-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

RIDER A.F.S.
(Alternate Feed Service Rider)

TERMS OF CONTRACT.

The AFS agreement under this rider will be made for a period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this rider.

Disconnection of AFS under this rider due to reliability or safety concerns associated with customer-owned transfer switches will not relieve the customer of payments required hereunder for the duration of the agreement term.

SPECIAL TERMS AND CONDITIONS.

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

Upon receipt of a request from the customer for non-standard AFS (AFS which includes unique service characteristics different from standard AFS), the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. An AFS agreement will be filed with the Commission under the 30-day filing procedures. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

The Company assumes no liability should the AFS circuit, transfer switch, or other equipment required to provide AFS fail to operate as designed, is unsatisfactory, or is not available for any reason.

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 33-1
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 33-1

U.G.R.T.
(Utility Gross Receipts Tax)
(School Tax)

APPLICABLE.

To all Tariff Schedules.

RATE.

This tariff schedule is applied as a rate increase pursuant to KRS 160.617 to all other tariff schedules for the recovery by the utility of the utility gross receipts license tax imposed by the applicable school district pursuant to KRS 160.613 with respect to the customer's bill. The current utility gross receipts license tax for school imposed by a school district may not exceed 3%. The utility gross receipts license tax shall appear on the customer's bill as a separate line item.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

K.S.T.
(Kentucky Sales Tax)

APPLICABLE.

To all Tariff Schedules.

RATE.

This tariff schedule is applied as a rate increase to all other applicable tariff schedules for the recovery by the utility pursuant to KRS 139.210 of the Kentucky Sales Tax imposed by KRS 139.200 for all customers not exempted by KRS 139.470(8). For any other exempt customers, an exemption certification must be received and on file with the Company. The Kentucky Sales Tax rate is currently imposed by the Commonwealth of Kentucky at the rate of 6%. The Kentucky Sales Tax shall appear on the customer's bill as a separate line item.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 35-1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 35-1

TARIFF P.P.A.
(Purchase Power Adjustment)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., ~~Experimental~~ S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ~~Q.P., C.I.P.-T.O.D.~~ *I.G.S.*, C.S.- I.R.P., M.W., O.L. and S.L. T T

RATE.

1. In accordance with the Stipulation and Settlement Agreement approved as modified by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the purchase power adjustment shall provide for monthly adjustments based on a percent of revenues, calculated to six decimal places and equal to the net costs of any power purchases in the current period according to the following formula:

$$\text{Monthly Purchase Power Adjustment Factor} = \frac{\text{Net KY Retail P(m)}}{\text{KY Retail R(m)}}$$

Where:

Net KY Retail P(m) = Monthly P(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month (m). (For purposes of this formula, Total Company Revenues include only Retail and Full-Requirements Wholesale revenues.)

KY Retail R(m) = Kentucky Retail Revenues for the Expense Month (m).

2. The net costs of any power purchased shall exclude costs recovered through the Fuel Adjustment Clause and shall be computed as the sum of the following items:

   a. PPA(m) = The cost of power purchased by the Company through new Purchase Power Agreements (PPAs). All new PPAs shall be approved by the Commission to the extent required by KRS 278.300.
   b. RP(m) = The cost of fuel related substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages.
   c. *PE(m)= The cost of power purchased unrelated to forced generation or transmission outages that are calculated in accordance with the peaking unit equivalent methodology.* N
   d. CSIRP(m) = The cost of any credits provided to customers under Tariff C.S.-I.R.P. for interruptible service.

   Monthly P(m) = PPA(m) + RP(m)+*PE(m)* + CSIRP(m) T

3. The monthly purchase power adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment, which shall include data, and information as may be required by the Commission.

4. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 36-1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 36-1

TARIFF A.T.R.
(Asset Transfer Rider)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., ~~Experimental~~ S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., ~~Q.P., C.I.P.-T.O.D.~~ *I.G.S.*, C.S.- I.R.P., M.W., O.L. and S.L. T T

RATE.

In accordance with the Stipulation and Settlement Agreement approved as modified by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, Kentucky Power Company is to recover from retail ratepayers $44 million annually beginning January 1, 2014. ~~and ending when the Commission sets new base rates for the Company that include Mitchell Units 1 and 2.~~ T

Recovery under Tariff A.T.R. shall terminate on the effective date of new base rates for the Company that include Mitchell Units 1 and 2, except that the Company shall recover through the Residential Asset Transfer Adjustment and the All Other Classes Transfer Adjustment such amounts as required to ensure the Company recovers in the year new base rates for the Company are established that include Mitchell Units 1 and 2 a pro rata share (computed on a 365-day annual basis) of the $44 million annual revenue requirement under Tariff A.T.R.. N N

1. The allocation of the $44 million revenue requirement between residential and all other customers shall be based upon their respective contribution to total retail revenues for the twelve month period ended September 30, 2013, according to the following formula:

$$\text{Residential Allocation RA(m)} = \frac{\$44{,}000{,}000}{12 \text{ months}} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}} = \$1{,}541{,}861$$

$$\text{All Other Allocation OA(m)} = \frac{\$44{,}000{,}000}{12 \text{ months}} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}} = \$2{,}124{,}806$$

Where:
(m) = the expense month; RR(b) = $214,421,664
(b) = twelve month period ended September 30, 2013. OR(b) = $295,489,874
R(b) = $509,911,538

2. The Residential Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of total revenues, calculated to six decimal places according to the following formula:

$$\text{Residential Asset Transfer Adjustment Factor} = \frac{\text{Net Monthly Residential Allocation NRA(m)}}{\text{Residential Retail Revenue RR(m)}}$$

Where:
Net Monthly Residential Allocation NRA(m) = Monthly Residential Allocation RA(m), net of Over/(Under) Recovery Adjustment;

Residential Retail Revenue RR(m) = Monthly Retail Revenue for all KY residential classes for the expense month (m).

3. The All Other Classes Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of non-fuel revenues, calculated to six decimal places according to the following formula:

$$\text{All Other Classes Asset Transfer Adjustment Factor} = \frac{\text{Net Monthly All Other Allocation NOA(m)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(m)}}$$

Where:
Net Monthly All Other Allocation NOA(m) = Monthly All Other Allocation OA(m), net of Over/(Under) Recovery Adjustment;

All Other Classes Non-Fuel Retail Revenue ONR(m) = Monthly Non-Fuel Retail Revenue for all classes other than residential for the expense month (m).

(Cont'd on Sheet 36-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF A.T.R.
(Asset Transfer Rider)

RATE. (Cont'd)

5. The monthly asset transfer rider adjustments shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

N

TARIFF E.D.R.
(Economic Development Rider)

AVAILABILITY OF SERVICE.

To encourage economic development in the Company's service territory, limited-term reductions in billing demand charges described herein are offered to qualifying new and existing retail customers who make application for service under this Rider.

Service under this Economic Development Rider (EDR) is intended for specific types of commercial and industrial customers whose operations, by their nature, will promote sustained economic development based on plant and facilities investment and job creation. Availability is limited to customers on a first-come, first-served basis until such time as a total of 250 MW of new load has been added to Kentucky Power's system under the EDR. The EDR is available to commercial and industrial customers served under Tariffs L.G.S., Q.P. or C.I.P.-T.O.D. who meet the following requirements:

(1) A new customer must have at least a monthly maximum billing demand of 500 kW. An existing customer must increase its monthly maximum billing demand by at least 500 kW over the current Base Maximum Billing Demand in order to receive the Incremental Billing Demand Discount (IBDD).

(2) A new customer, or the business expansion by an existing customer, will receive a Supplemental Billing Demand Discount (SBDD) for creating and sustaining at least 25 new permanent full time jobs over the contract term at the service location. The Company reserves the right to verify job counts. Failure to demonstrate the creation of new employment positions or to maintain the employment during the contract term will result in the termination of the supplemental discount.

(3) The customer must demonstrate to the Company's satisfaction that, absent the availability of this EDR, the qualifying new or increased electrical demand would be located outside of the Company's service territory or would not be placed in service.

TERMS AND CONDITIONS.

(1) The Company will offer the EDR to qualifying customers with new or increased load when the Company has sufficient generating capacity available. When sufficient generating capacity is not available, the Company will procure the additional capacity on the customer's behalf. The cost of capacity procured on behalf of the customer shall reduce on a dollar-for-dollar basis the customer's IBDD and SBDD. Such reduction shall be capped so that the customer's maximum demand charge shall be the non-discounted tariff demand charge. The reduction will be applied in reverse chronological order beginning with the most recent customer to receive discounted service under this tariff. Last customer to sign up for the EDR tariff would be the first customer responsible for paying the cost of incremental capacity purchases. In any year during the discount period in which the customer pays the full tariff demand charge for all twelve months, the Company will reduce the term of the contract by one year.

(2) The new or increased load cannot accelerate the Company's plans for additional generating capacity during the period for which the customer receives a demand discount. Customers receiving Temporary Service are not eligible for this EDR.

(3) To receive service under this EDR, the customer shall make written application to the Company with sufficient information contained therein to determine the customer's eligibility for service. At a minimum, such information will include:

(Cont'd on Sheet 37-2)

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

N

TARIFF E.D.R. (Cont'd)
(Economic Development Rider)

TERMS AND CONDITIONS-(Cont'd).

a. A description and good faith estimate of the new or increased load to be served during each year of the contract,
b. The number of new employees or jobs that will be added as a result of the new load,
c. A description of the anticipated capital investment, and
d. A description of all other federal, state or local economic development tax incentives, grants, or any other incentives / assistance associated with the new or expanded project.
e. A statement that without the EDR discount, the customer would locate elsewhere or chose not to expand within Kentucky Power's service territory.

(3) For new and existing customers, billing demands for which reductions will be for service at a new service location or expanded production at an existing facility and not merely the result of a change of ownership. Relocation of the delivery point of the Company's service, moving existing equipment from another KPCo-served location or load transfers from another KPCo-served location do not qualify as a new service location. Relocating existing facilities from within the Company's service territory shall not disqualify the customer from the IBDD as long as the new relocated facility exceeds the Base Maximum Billing Demand of the previous facility by the minimum required amount.

(4) For existing customers, billing demands for which deductions will be applicable under this EDR shall be the result of an increase in business activity and not merely the result of resumption of normal operations following a force majeure, strike, equipment failure, renovation or refurbishment, or other such abnormal operating condition. In the event that such an occurrence has taken place prior to the date of the application by the customer for service under this EDR, the monthly Base Maximum Billing Demand shall be adjusted as appropriate for this analysis to eliminate the effects of such occurrence.

(5) Service under the EDR will be offered under the applicable Tariff L.G.S., Q.P. or C.I.P.-T.O.D schedule. An EDR will be filed as a Special Contract and must be approved by the Kentucky Public Service Commission before it can be implemented. The total contract period is equal to twice the number of years for which the customer receives a demand discount. The special contract term will be for two (2), four (4), six (6), eight (8), and (ten) 10 years only.

(6) The IBDD and the SBDD, if applicable, begin when the customer's new or expanded operations are billed for service under this Rider. Temporary jobs created during the construction of new facilities or the expansion phase of existing operations are not eligible to be counted as permanent jobs for the purposes of this EDR.

(7) If construction of new or expanded local distribution and/or transmission related facilities by the Company is required in order to provide the additional service, the customer may be required to make a contribution-in-aid of construction (CIAC) for the installed cost of such facilities pursuant to the provisions of the Company's Terms and Conditions of Service. The total cost of the CIAC, including gross-up by the effect of applicable taxes, will be recovered over the life of the EDR contract period, with no less than 80% recovered during the period for which the customer receives a demand discount. If the customer breaches the terms of the contract or ends the contract prematurely, any unpaid contribution-in-aid of construction must be paid to the Company and any EDR discounts provided to the customer must be repaid to the Company. CIAC payment provided under this Rider supersedes the other payment provisions only in the Company's Terms and Conditions Sheet 2-5 Section 9.

(Cont'd on Sheet 37-3)

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

N

TARIFF E.D.R. (Cont'd)
(Economic Development Rider)

TERMS AND CONDITIONS (Cont'd).

(8) The L.G.S., Q.P. and CIP-TOD tariffs each contain a monthly minimum billing demand charge provision. The minimum demand charge provision is waived for EDR customers for up to 36 months depending upon the length of the contract. The provision is waived for the first 36 months of a 10 year contract, the first 24 months of an 8 year contract and the first 12 months of a 6 year contract. If during the special contract discount period, the customer's monthly demand falls below the minimum billing demand level for four (4) consecutive months or six (6) months total in a contract year, then the EDR discount will not be applied and the appropriate tariff minimum billing demand charge provision will be in force until the customer achieves the minimum billing demand level. Applicable EDR discounts will be applied to the qualifying incremental maximum billing demand only and will appear as a separate line item on the customer's bill.

DETERMINATION OF MONTHLY QUALIFYING INCREMENTAL BILLING DEMAND.

For the purposes of this Rider, the monthly qualifying incremental billing demand will be calculated in the following manner:

Where the new qualifying incremental demand resides in new facilities (or separate facilities for existing customers), those facilities may be metered on a separate meter according to Tariffs L.G.S., Q.P. or C.I.P.-T.O.D. for the current billing period and the incremental billing demand will be calculated based upon that facility's meter readings.

Where the new qualifying incremental demand resides in a customer's existing facility with sufficient service and metering capability to accommodate the business expansion, the qualifying incremental billing demand is equal to demand in excess of the Base Maximum Billing Demand. The Base Maximum Billing Demand for each billing month will be calculated by the Company as the average of the previous three years, corresponding month maximum billing demands, subject to Terms and Conditions Items (3) and (4), and will be agreed to by the customer in advance.

DETERMINATION OF INCREMENTAL BILLING DEMAND DISCOUNT.

Customers meeting all Availability of Service and Terms and Conditions above may contract for service for a period of up to ten (10) years, with a commensurate discount period of up to five (5) years. The (IBDD) for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced by 50% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. demand charge;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced by 40% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. demand charge;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced by 30% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. demand charge;

N

(Cont'd on Sheet 37-4)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.D.R. (Cont'd)
(Economic Development Rider)

N

DETERMINATION OF INCREMENTAL BILLING DEMAND DISCOUNT (Cont'd).

(d) *For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced by 20% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. charge, but shall not be less than the applicable tariff rate schedule minimum billing demand;*

(e) *For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced by 10% from the applicable tariff L.G.S., Q.P. or C.I.P.-T.O.D. demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand; and*

(f) *All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10).*

The starting point for the IBDD is dependent upon the length of contract: i.e., an eight (8) year contract will have four (4) years of discount beginning with the IBDD of 40% in year one (1). Similarly, a six (6) year contract will have three (3) years of discount beginning with the IBDD of 30% in year one (1).

DETERMINATION OF SUPPLEMENTAL BLLING DEMAND DISCOUNT.

At the Company's discretion, a (SBDD) which is applicable to the monthly incremental billing demand charge is available to customers meeting all Availability of Service and Terms and Conditions above, and that create at least twenty five (25) new permanent job opportunities in the facility and that maintain those job opportunities in each discount year. The amount of additional discount is determined by the actual number of jobs maintained in each year. The SBDD for a ten (10) year contract follows:

(a) *For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced an additional 5% for an increase of at least 50 jobs or 2.5% for an increase of at least 25 jobs;*

(b) *For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced 4.5% for at least 50 jobs or 2.0% for at least 25 jobs.*

(c) *For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced an additional 4% for an increase of at least 50 jobs or 1. 5% for an increase of at least 25 jobs;*

(d) *For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3.5% for an increase of at least 50 jobs or 1. 0% for an increase of at least 25 jobs;*

N

(Cont'd on Sheet 37-5)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF E.D.R. (Cont'd)
(Economic Development Rider)

N

DETERMINATION OF SUPPLEMENTAL BLLING DEMAND DISCOUNT (Cont'd).

(e) *For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3% for an increase of at least 50 jobs or 0.5% for an increase of at least 25 jobs; and*

(f) *All subsequent monthly billing shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10)*

The length of the SBDD shall be identical to the length of the IBDD. The starting point for the discount will be commensurate with the contract length, i.e., an eight (8) year contract will have four (4) years of discount with the SBDD of either 4.5% or 2.0% as appropriate in year one (1).

The appropriate discount(s) shall be applicable over a period of up to 60 consecutive billing months beginning with the first such month following the end of the start-up period. The start-up period shall commence with the effective date of the contract addendum for service under this EDR and shall terminate by mutual agreement between the Company and the customer. In no event shall the start-up period exceed 12 months.

TERMS OF CONTRACT.

A contract or agreement addendum for service under this Rider, in addition to service under Tariffs L.G.S., Q.P. or C.I.P.-T.O.D., shall be executed by the customer and the Company for the time period which includes the start-up period and the multi-year period during which a Total Demand Charge discount is in effect and an equal multi-year period during which the customer agrees to pay the full rates in the applicable Tariff rate schedule.

At a minimum, the contract or agreement addendum shall specify the Base Maximum Billing Demand, the anticipated annual total qualifying demand, the Adjustment Factor and related provisions to be applicable under this Rider, and the effective date for the contract addendum.

The customer may discontinue service under this Rider before the end of the contract or agreement addendum only by reimbursing the Company for any and all demand reductions received under this Rider when billed at the applicable tariff schedule rate.

SPECIAL TERMS AND CONDITIONS.

Except as otherwise provided in this Rider, written agreements shall remain subject to all of the provisions of the applicable tariffs. This Rider is subject to the Company's Terms and Conditions of Service.

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 38-1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 38-1

N

BIG SANDY RETIREMENT RIDER
(B.S.R.R.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L. and S.L.

RATE.

1. *Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) carrying cost over a 25 year period beginning when new base rates are set for the Company that include Mitchell Units 1 and 2. The term "Retirement Costs" as used in this agreement are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.*

2. *The allocation of the levelized revenue requirement (LRR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent calendar twelve month period, according to the following formula:*

$$\text{Residential Allocation } RA(m) = LRR(m) \times \frac{\text{KY Residential Retail Revenue } RR(b)}{\text{KY Retail Revenue } R(b)}$$

$$\text{All Other Allocation } OA(m) = LRR(m) \times \frac{\text{KY All Other Classes Retail Revenue } OR(b)}{\text{KY Retail Revenue } R(b)}$$

Where:
(m) = the expense month;

(b) = Most recent available twelve calendar-month period ended December 31.

3. *The Residential Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of total revenues, according to the following formula:*

$$\text{Residential Asset Transfer Adjustment Factor} = \frac{\text{Net Monthly Residential Allocation } NRA(m)}{\text{Residential Retail Revenue } RR(m)}$$

Where:
Net Monthly Residential Allocation NRA(m) = Monthly Residential Allocation RA(m), net of Over/(Under) Recovery Adjustment;

Residential Retail Revenue RR(m) = Monthly Retail Revenue for all KY residential classes for the expense month (m).

N

(Cont'd on Sheet No. 38-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 38-2
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 38-2

BIG SANDY RETIREMENT RIDER(CONT'D)
(B.S.R.R.)

N

RATE. (Cont'd)

4. *The All Other Classes Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of non-fuel revenues, according to the following formula:*

All Other Classes Asset Transfer Adjustment Factor	=	*Net Monthly All Other Allocation NOA(m)* / *All Other Classes Non-Fuel Retail Revenue ONR(m)*

Where:

Net Monthly All Other Allocation NOA(m)	=	*Monthly All Other Allocation OA(m), net of Over/(Under) Recovery Adjustment;*
All Other Classes Non-Fuel Retail Revenue ONR(m)	=	*Monthly Non-Fuel Retail Revenue for all classes other than residential for the expense month (m).*

5. *The monthly Big Sandy Retirement Rider adjustments shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.*

6. *Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884.*

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 39-1
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 39-1

N

BIG SANDY UNIT 1 OPERATION RIDER
(B.S.1.O.R.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES.

Tariff Class	*\$/kWh*	*\$/kW*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	*\$0.00330*	--
S.G.S. and S.G.S.-T.O.D.	*\$0.00272*	--
M.G.S.	*\$0.00141*	*\$0.34*
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	*\$0.00283*	--
L.G.S. and L.G.S.-T.O.D.	*\$0.00139*	*\$0.45*
L.G.S.-L.M.-T.O.D.	*\$0.00276*	--
I.G.S. and C.S.-I.R.P.	*\$0.00139*	*\$0.55*
M.W.	*\$0.00248*	--
O.L.	*\$0.00147*	--
S.L.	*\$0.00147*	--

Tariff BS1OR includes all non-fuel operating expenses related to Big Sandy Unit 1 not otherwise included in Tariff S.S.C. or Tariff FAC. Tariff BS1OR shall also include a return on and of Big Sandy Unit 1 gas conversion capital when placed in service.

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS and IGS tariff classes.

The Big Sandy Unit 1 Operation Rider factors shall be modified annually to collect the approved annual level of Kentucky retail jurisdictional Big Sandy Unit 1 revenue requirement and any prior review period (over)/under recovery.

The Big Sandy Unit 1 Operation Rider factors shall be determined as follows:
For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{BS1E \times (BE_{Class}/BE_{Total}) + BS1D \times (CP_{Class}/CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{BS1E \times (BE_{Class}/BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{BS1D \times (CP_{Class}/CP_{Total})}{BD_{Class}}$$

(Cont'd on Sheet No.39-2)

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 39-2**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 39-2

BIG SANDY UNIT 1 OPERATION RIDER (CONT'D)
(B.S.1.O.R) N

RATES. (Cont'd)

Where:

1. *"BS1D" is the actual annual retail Big Sandy Unit 1 demand-related costs, plus any prior review period (over)/under recovery.*

2. *"BS1E" is the actual annual retail Big Sandy Unit 1 energy-related costs, plus any prior review period (over)/under recovery.*

3. *"BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.*

4. *"BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.*

5. *"CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:*

Tariff Class	BE_{Class}	*CP/kWh Ratio*	CP_{Class}
(1)	*(2)*	*(3)*	*(4)=(2)x(3)*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D.		*0.0236060%*	
S.G.S and S.G.S.-T.O.D.		*0.0163937%*	
M.G.S.		*0.0177002%*	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		*0.0177002%*	
L.G.S.and L.G.S.-T.O.D.		*0.0169381%*	
L.G.S.-L.M.-T.O.D.		*0.0169381%*	
I.G.S. and C.S.-I.R.P		*0.0130626%*	
M.W.		*0.0134057%*	
O.L.		*0.0009431%*	
S.L.		*0.0009890%*	
	BE_{Total}		CP_{Total}

6. *"BE_{Total}" is the sum of the BE_{Class} for all tariff classes.*

7. *"CP_{Total}" is the sum of the CP_{Class} for all tariff classes.*

The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the Big Sandy Unit 1 Operation Rider revenues.

The annual Big Sandy Unit 1 Operation Rider factors shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY — P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 40-1
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 40-1

N

NERC COMPLIANCE AND CYBERSECURITY RIDER (N.C.C.R.)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES.

Tariff Class	*¢/kWh*	*$/kW*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	*0.0000*	--
S.G.S. and S.G.S.-T.O.D.	*0.0000*	--
M.G.S.	*0.0000*	*0.00*
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	*0.0000*	--
L.G.S. and L.G.S.-T.O.D.	*0.0000*	*0.00*
L.G.S.-L.-M.T.O.D.	*0.0000*	*0.00*
I.G.S. and C.S.-I.R.P.	*0.0000*	*0.00*
M.W.	*0.0000*	--
O.L.	*0.0000*	--
S.L.	*0.0000*	--

The kWh adjustment factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW adjustment factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS and IGS tariff classes.

The NERC Compliance and Cybersecurity Rider adjustment factors shall be modified annually to collect the Commission's approved annual level of Kentucky retail jurisdictional NERC Compliance and Cybersecurity expenses and any prior review period (over)/under recovery.

The NERC Compliance and Cybersecurity Rider adjustment factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Adjustment Factor} = \frac{NCE \times (BE_{Class} / BE_{Total}) + NCD \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Adjustment Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Adjustment Factor} = \frac{NCE \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Adjustment Factor} = \frac{NCD \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

(Cont'd on Sheet No. 40-2)

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 40-2**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 40-2

NERC COMPLIANCE AND CYBERSECURITY RIDER (CONT'D)
(N.C.C.R.)

N

RATES: (Cont'd)

Where:

1. *"NCD" is the actual annual retail NERC Compliance and Cybersecurity demand-related costs, plus any prior review period (over)/under recovery.*

2. *"NCE" is the actual annual retail NERC Compliance and Cybersecurity energy-related costs, plus any prior review period (over)/under recovery.*

3. *"BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.*

4. *"BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.*

5. *"CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:*

Tariff Class	*BE_{Class}*	*CP/kWh Ratio*	*CP_{Class}*
(1)	*(2)*	*(3)*	*(4)=(2)x(3)*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2		*0.0236060%*	
S.G.S. and S.G.S.-T.O.D.		*0.0163937%*	
M.G.S.		*0.0177002%*	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		*0.0177002%*	
L.G.S.and L.G.S.-T.O.D.		*0.0169381%*	
L.G.S.-L.M.-T.O.D.		*0.0169381%*	
I.G.S. and C.S.-I.R.P.		*0.0130626%*	
M.W.		*0.0134057%*	
O.L.		*0.0009431%*	
S.L.		*0.0009890%*	
	BE_{Total}		*CP_{Total}*

6. *"BE_{Total}" is the sum of the BE_{Class} for all tariff classes.*

7. *"CP_{Total}" is the sum of the CP_{Class} for all tariff classes.*

The adjustment factor as computed above shall be further modified to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the NERC Compliance and Cybersecurity Rider adjustment revenues.

N

(Cont'd on Sheet No. 40-3)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

NERC COMPLIANCE AND CYBERSECURITY RIDER (CONT'D)
(N.C.C.R.)

N

RATES. (Cont'd)

The initial NERC Compliance and Cybersecurity Rider adjustment factors shall be filed with the Commission six (6) months before the initial rates are scheduled to go into effect and ten (10) days before any subsequent annual rate adjustments are scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

N

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)	Case No. 2014-00396

DIRECT TESTIMONY OF

STEGALL, STOGRAN, VAUGHAN, WOHNHAS, AND YODER

ON BEHALF OF KENTUCKY POWER COMPANY

SECTION III

VOLUME 4 OF 4

December 23, 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	**)**	
A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	
Environmental Compliance Plan; (3) An Order	**)**	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

JASON M. STEGALL

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jason M. Stegall, being duly sworn, deposes and says he is the a Regulatory Consultant for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Jason M. Stegall

STATE OF OHIO)
) Case No. 2014-00396
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jason M. Stegall, this the 11th day of December, 2014.

Notary Public

My Commission Expires: 10/1/2019

NOTARIAL SEAL STATE OF OHIO

Kelli N. Beuzard
Notary Public, State of Ohio
My Commission Expires 10-01-2019

DIRECT TESTIMONY OF
JASON M. STEGALL, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
JASON M. STEGALL, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Jason M. Stegall. My business address is 1 Riverside Plaza, Columbus, Ohio. I currently hold the position of Regulatory Consultant in the Regulated Pricing and Analysis department for the American Electric Power Service Corporation ("AEPSC"), a subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or "Company") and AEPSC is Kentucky Power's services provider company.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR BACKGROUND AND EMPLOYMENT HISTORY.

A. In May 1997, I earned my Bachelor of Science Degree in Accounting from Virginia Polytechnic Institute and State University. In August 2011, I earned my Master's Degree in Business Administration from the Ohio State University.

In June 1997, I joined AEPSC as an Accountant in the Regulated Accounting Division of the Accounting Department. In July 2009, I joined the Regulatory Services Department as a Regulatory Consultant. From July 2009 through June 2010, I performed duties as a Regulatory Consultant in Customer and Distribution Services Support, where I was responsible for assisting customer services and distribution services witnesses in regulatory proceedings by supporting testimony preparation, providing research in support of the discovery process, and compiling data for regulatory filings. In July 2010, I joined Regulated Pricing & Analysis, where my responsibilities include preparation of cost-of-service studies, rate design and tariff provisions for the AEP operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony before the Kentucky Public Service Commission in Case No. 2013-00197. In addition, I have submitted testimony before the Indiana Utility Regulatory Commission and the Michigan Public Service Commission regarding cost-of-service and rate design.

III. <u>PURPOSE OF DIRECT TESTIMONY</u>

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

A. The purpose of my testimony is to support three test year revenue adjustments, to address the allocation of the requested rate increase to Kentucky Power's customer classes, and to support and describe the development of the Company's Class Cost-of-Service Study.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring the following exhibits:

Exhibit JMS-1	Customer Annualization Adjustment
Exhibit JMS-2	Class Cost-of-Service Study
Exhibit JMS-3	Revenue Allocation

IV. REVENUE ADJUSTMENTS

Q. ARE YOU RESPONSIBLE FOR THE DEVELOPMENT OF THE CUSTOMER MIGRATION ADJUSTMENT?

A. Yes.

Q. PLEASE DESCRIBE THE ADJUSTMENT.

A. The purpose of the customer migration adjustment is to determine the test year revenue that Kentucky Power would have received if each customer were billed for the entire twelve months of the test year on the tariff under which the customer was taking service at the end of the test year. For example, a customer may have been billed under the MGS (Medium General Service) tariff for the first seven months of the test year and then billed under the LGS (Large General Service) tariff for the remaining five months of the test year. During the test year, over 650 customers changed tariffs.

The Customer Migration Adjustment starts with the "per books revenue" as shown in Section III of this filing. "Per books revenues" means the revenues from customers as they were actually billed for each month of the test year. For purposes of the Customer Migration Adjustment, these customers would be re-billed for the entire test year under the tariff under which they received service at the end of the test year to determine the impact on test year revenues. This restatement of per books revenue was made for each customer who switched tariffs during the test year.

Q. WHAT IMPACT DOES THE CUSTOMER MIGRATION ADJUSTMENT HAVE ON TEST YEAR REVENUES?

A. The Customer Migration Adjustment results in an increase of test year revenues of $149,766 as shown in Section V, Schedule 5, Exhibit 2, W4.

Q. ARE YOU RESPONSIBLE FOR THE DEVELOPMENT OF THE WEATHER NORMALIZATION ADJUSTMENT?

A. Yes.

Q. PLEASE DESCRIBE THE ADJUSTMENT.

A. The purpose of the Weather Normalization Adjustment is to restate test year revenues and expenses to reflect a 30-year average load compared to the abnormal weather experienced during the test year. During the test year, the Company's service territory experienced its fifth coldest winter in the last 30 years, which included the January 6-8, 2014, Polar Vortex that caused PJM to reach a new wintertime peak. This is partially offset by the fifth coolest summer over the past 30 years.

Using data provided by the Company's Economic Forecasting Group, the adjustment was calculated to reduce residential energy usage to the level of the 30-year average in order to eliminate the effect of the aberrant weather discussed in the paragraph above. The adjustment was limited to the residential customer class because these customers have the highest correlation of energy usage to weather. The result of this adjustment was to reduce total usage by approximately 63.5 million kilowatt-hours and reduce revenues by $5,929,131.

In addition to the $5,929,131 decrease in test year revenues, test year operating expenses must also be decreased to reflect the incremental costs Kentucky Power would avoid.

The operating ratio is simply the ratio of operation and maintenance expense, less labor expense, to operating revenues. For Kentucky Power, the operating ratio is 59.86%. Incremental operating expenses are then calculated by multiplying the reduction in operating revenue ($5,929,131) by the operating ratio (59.86%) to yield ($3,548,711). Incremental state and federal income taxes are also deducted to yield a net Weather Normalization Adjustment of ($1,458,540) as shown in Section V, Schedule 5, Exhibit 2, W2.

Q. ARE YOU RESPONSIBLE FOR THE DEVELOPMENT OF THE CUSTOMER ANNUALIZATION ADJUSTMENT?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF THE ADJUSTMENT.

A. The purpose of the Customer Annualization Adjustment is to restate test year revenues and expenses to reflect, on an annual basis, changes in load that occurred during the test year. For example, if the number of residential customers increased during the test year, per books residential kWh sales would have to be increased to reflect the impact of annualizing load growth that occurred within the test year. In addition to the revenue adjustment, test year operating expenses would also have to be increased to reflect the incremental costs associated with annualizing test year load growth.

Q. PLEASE DESCRIBE THE ADJUSTMENT.

A. The development of the Customer Annualization Adjustment is shown in Exhibit JMS-1 with additional detail shown in Section III of this filing. To ensure that the Customer Annualization Adjustment reflects only actual customer growth, the impact of customer migrations has been eliminated by starting with the data adjusted for the Customer Migration Adjustment.

Page 1 of Exhibit JMS-1 shows specific changes in large customer loads as identified by Kentucky Power. Column (1) contains Kentucky Power's current tariffs listed by delivery voltage level. Column (2) contains the total number of customers for the test year, while Column (3) contains the number of customers as of September 30 2014. Columns (4) and (5) show metered kWh and revenues, respectively. Columns (6) through (9) show the specific adjustments for known changes in large customer usage and the previously mentioned Weather Normalization Adjustment. The known customer changes produce an increase in revenue of $2,320,420, which produces a reduction in revenue of $3,608,711 when netted against the Weather Normalization Adjustment. Columns (10) through (13) are the sum of the data shown in Columns (2) through (5) and the adjustments shown in columns (6) through (9). This information is the starting point for the second part of the Customer Annualization Adjustment that is shown on page 2 of Exhibit JMS-1.

Column (1) of page 2 of Exhibit JMS-1 contains Kentucky Power's current tariffs listed by delivery voltage level. Column (2) contains the total number of customers for the test year, while Column (3) contains the average number of customers for the test year [Column (2) divided by 12]. Column (4) contains the number of customers as of September 30, 2014. Customer growth [Column (5)] is calculated as Column (4) less Column (3).

Customer growth [Column (5)] is then multiplied by test year average kWh per customer [Column (7)] to yield the kWh annualization adjustment [Column (8)]. The kWh annualization adjustment is in turn multiplied by the test year average revenue per kWh [Column (10)] to yield a revenue annualization adjustment of ($2,719,824) as shown in Column (11).

In addition to the $399,403 decrease ($2,320,420 + ($2,719,824)) in test year revenues resulting from the first two steps of the Customer Annualization Adjustment, test year operating expenses must also be decreased to reflect the incremental cost Kentucky Power would avoid.

The operating ratio is simply the ratio of operation and maintenance expense, less labor expense, to operating revenues. For Kentucky Power, the operating ratio is 59.86%. Incremental operating expenses are then calculated by multiplying the reduction in operating revenue ($399,403) by the operating ratio (59.86%) to yield ($239,052). Incremental state and federal income taxes are also deducted to yield a net Customer Annualization Adjustment of ($98,251) as shown in Section V, Exhibit 2, W5.

V. <u>CLASS COST-OF-SERVICE STUDY</u>

Q. PLEASE DESCRIBE THE GENERAL PURPOSE OF A COST-OF-SERVICE STUDY.

A. A cost-of-service study is a basic analytical tool used in traditional utility rate design. A cost-of-service study is used to determine the revenue requirement for the services offered by the utility, and it analyzes, at a very detailed level, the costs that different classes of customers impose on the utility system. A completed class cost-of-service study shows the total costs the Company incurs in serving each retail rate class as well as the rate of return on rate base earned from each class during the test year. When the process of preparing a cost-of-service study is completed and all of the costs are allocated to the customer classes, the result establishes cost responsibility and makes it possible to determine rates based on costs that are just and reasonable.

Q. WHAT DATA SOURCE IS USED IN THE DEVELOPMENT OF A COST-OF-SERVICE STUDY?

A. The historic accounting records of Kentucky Power are used in the cost-of-service studies. These accounting records are reflected in the jurisdictional cost-of-service study, as shown in Section V of this filing, and in the class cost-of-service study. The Company follows the Uniform System of Accounts (USOA) as prescribed by FERC and adopted by this Commission. The USOA sets the guidelines for recording assets, liabilities, income and expenses into various accounts. The costs recorded in each FERC account are examined to verify compliance with these guidelines and are typically adjusted to reflect the applicable regulatory commission's policies and for known and measurable changes to the test year level of expenditures.

Q. AFTER THE COSTS RECORDED IN FERC ACCOUNTS ARE EXAMINED AND ADJUSTED, WHERE APPROPRIATE, HOW ARE THESE COSTS ASSIGNED TO EACH CUSTOMER CLASS?

A. This accounting cost information is assigned to the different customer classes in a way that reflects the costs of providing utility service to the various customer classes. This is accomplished using a standard three-step process: functionalization of costs, classification of costs, and, finally, allocation of costs.

Q. PLEASE EXPLAIN THE FUNCTIONALIZATION PROCESS.

A. Functionalization is the process of separating costs according to electric system functions. Typically, functions in an electric utility include the following:

1) Production and Purchased Power costs,

2) Transmission costs,

3) Distribution costs,

4) Customer Service costs, and

5) Administrative and General ("A&G") costs.

The production function includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission function consists of costs associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities to the load centers of the utility's system. The distribution function includes the radial distribution system that connects the transmission system and the ultimate customer. The customer service function encompasses the costs associated with providing meter reading, billing and collection, and customer information and services. The A&G function is comprised of costs that may not be directly assignable to other cost functions. These costs include such items as management costs and administrative buildings. A&G costs are generally allocated to the remaining functions based on labor.

Q. PLEASE EXPLAIN THE CLASSIFICATION PROCESS.

A. The second step is to separate the functionalized costs into classifications of demand costs, energy costs, and customer costs.

Typical cost classifications used in cost studies include the following:

Function	Classification
Production	Demand, Energy
Transmission	Demand
Distribution	Demand, Customer
Customer Service	Customer

Demand costs are associated with the kW demand imposed by the customer. These are fixed costs which are incurred regardless of the level of energy sales. An example of a demand-related cost is the investment in production, transmission or distribution facilities, such as a generating unit including transmission and distribution poles and lines.

Energy costs vary with the number of kilowatt hours used by the customer. Production costs such as incremental fuel and certain production operation and maintenance expenses are energy-related since they vary with the level of sales of electricity.

Customer costs are directly related to the number of customers served. These are fixed costs which are incurred regardless of the level of energy sales. Meter and customer service costs are examples of costs whose levels are fixed by the number of customers.

The classification process provides a basis on which to allocate different categories of costs (demand, energy or customer) to the Company’s classes.

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS.

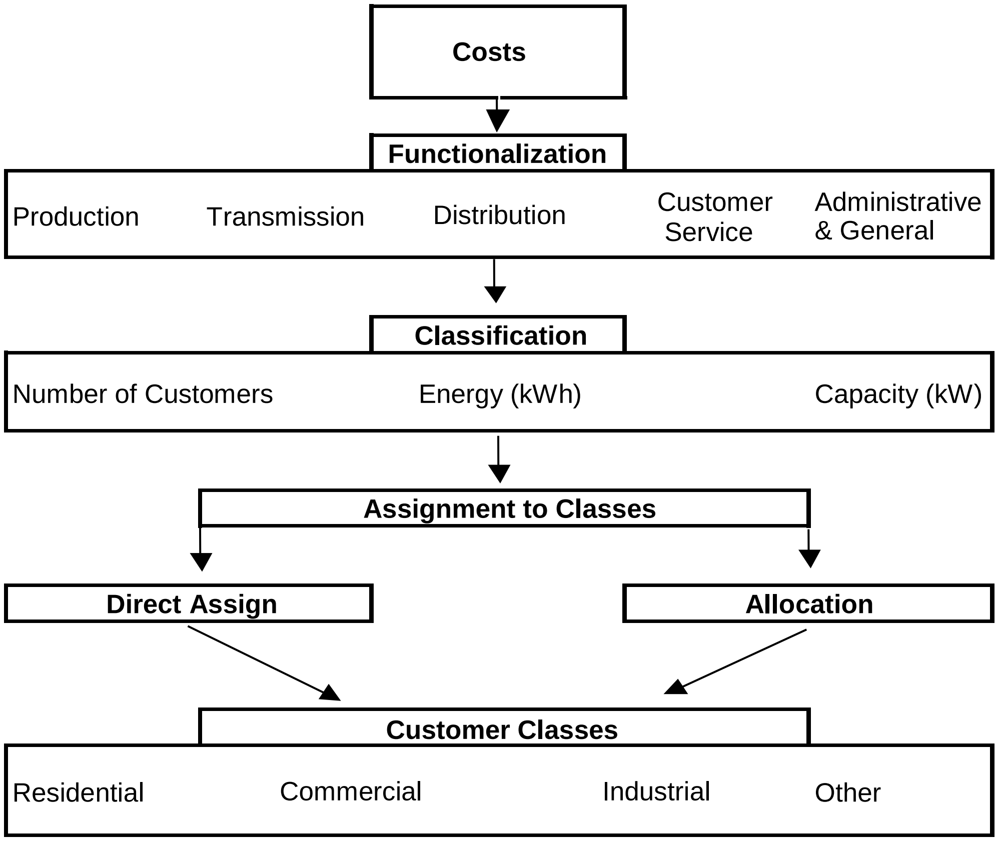
A. The third and final step is to allocate the functional and classified costs among the classes of customers based on how the costs are incurred for each class. Allocation factors are used to assign these costs to the various customer classes. Customer classes are determined and grouped according to the nature of service provided, voltage level and the load usage characteristics. The three principal customer classes are residential, commercial, and industrial.

The allocation process involves multiplying the functional and classified costs by the allocation factors, which results in costs assigned to each class. The objective in this process is to determine a reasonable, appropriate, and understandable method to assign the costs. Some costs are directly assignable to a single class, or even a single customer. For instance, the costs associated with the poles and luminaries used for street lighting are directly assigned to the street lighting class. Most costs, however, are attributable to more than one type of customer. These are joint costs and must be allocated to customers by an allocation methodology that is based on the manner in which the costs are caused by the different customers.

The following flowchart (Figure 1) provides an overview of how the allocation of costs to customer classes is determined.

Figure 1:

Cost Allocation Example



In the illustration above, costs are functionalized into production, transmission, distribution, etc. Some of these costs can be directly assigned to a customer class. The remaining joint costs are incurred based on the number of customers, the energy used, or by the capacity demanded. In many instances, the classification process will lead to an allocation methodology. For example, the cost of billing customers varies with the number of customers as well as the complexity of preparing the customer's bill, so those costs associated with billing are allocated to the customer classes based on a weighted number of customers. An allocation factor using a weighted number of customers is developed by multiplying the number of customers in each class by a factor representing the difference in cost associated with providing that service to different types of customers. Similarly, the cost of fuel varies by the number of kilowatt hours consumed and, therefore, is allocated based on the proportion of total energy used by a customer class.

The next step is the classification of the functionalized costs as demand-, energy- or customer-related. The final step in the cost assignment process is to allocate the functionalized and classified costs to the customer classes through the use of allocation factors.

When this process is completed and all of the costs are allocated to the customer classes, the result is a fully allocated cost study that establishes cost responsibility and makes it possible to determine rates based on costs that are just and reasonable.

Q. WHAT CRITERIA ARE USED WHEN SELECTING ALLOCATION FACTORS FOR EACH FUNCTIONAL AND CLASSIFIED COST?

A. Generally, the following criteria should be used to determine the appropriateness of an allocation methodology:

1) The method should reflect the planning and operating characteristics of the utility's system.

2) The method should recognize customer class characteristics such as energy usage, peak demand on the system, diversity characteristics, number of customers, etc.

3) The method should produce stable results on a year-to-year basis.

4) Customers who benefit from the use of the system should also bear appropriate cost responsibility for the system.

Q. DOES THE ALLOCATION METHOD EMPLOYED BY THE COMPANY MEET THESE OBJECTIVES?

A. Yes, it does. The allocation methodology utilized in the Company's cost-of-service study was chosen while considering each of the criteria listed above. The results of the cost-of-service study can be relied upon to determine the appropriate revenue requirement for the Kentucky Power customer classes.

VI. <u>ALLOCATION BASIS</u>

Q. PLEASE EXPLAIN THE ALLOCATION OF PRODUCTION PLANT.

A. After electric plant-in-service is functionalized into production, transmission, distribution and general plant, production plant is classified as demand-related and is allocated using the production demand allocation factor. The production demand allocation factor assigns costs based on the class contribution to the average of Kentucky Power's 12 monthly peaks on the production facilities for the test period ended September 30, 2014.

Q. PLEASE EXPLAIN HOW GENERATOR STEP-UP TRANSFORMERS WERE ALLOCATED.

A. Generator step-up transformers are included in transmission plant, but were allocated using the production demand allocation factor since they are more related to the production function.

Q. PLEASE EXPLAIN THE ALLOCATION OF TRANSMISSION PLANT.

A. Transmission plant, excluding generator step-up transformers, is classified as demand related and is allocated using the transmission demand allocation factor. The transmission demand allocation factor assigns costs based on the class contribution to the average of Kentucky Power's 12 monthly peaks on the transmission facilities.

Q. PLEASE EXPLAIN THE ALLOCATION OF DISTRIBUTION PLANT.

A. Distribution plant is classified as demand / customer related and allocated to the customer classes using factors based on demand levels or number of customers. Distribution plant accounts 360 through 368, as shown on Exhibit JMS-2, were classified solely as demand-related. Accounts 360, 361 and 362 were allocated to the distribution customer classes based on their contributions to the average of Kentucky Power's 12 monthly peak demands on the primary distribution system.

Accounts 364 through 368 were split into primary and secondary voltage functions based upon information contained in the company's records and the expertise of the company's distribution engineers. The primary portions of accounts 364 through 368 were allocated using the average of 12 monthly peak demands on the distribution system. The secondary component of accounts 364 through 368 were allocated based on a combination of each class's 12-month maximum demand and the summation of individual customers' annual maximum demands in each class served from those facilities. This process reflects the fact that some secondary facilities serve only one customer, while others serve two or more customers.

Services, account 369, was classified as customer-related and was allocated using the average number of secondary customers served.

Meter plant was allocated using the average number of customers weighted by a factor which considers the cost differential of various metering installations. Account 371 was directly assigned to the outdoor lighting class and account 373 was directly assigned to the street lighting class.

Q. PLEASE EXPLAIN HOW GENERAL AND INTANGIBLE PLANT WAS ALLOCATED.

A. General and intangible plant and investment reflects a composite demand, energy and customer classification. General and intangible plant investment is allocated on the basis of payroll labor.

Q. PLEASE DESCRIBE THE ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION.

A. Accumulated Provision for Depreciation and Amortization was functionalized and classified in a fashion similar to Electric Plant-in-Service. Production, transmission, distribution and general and intangible related amounts were allocated based upon the allocation of the related Electric Plant-in-Service costs.

Q. PLEASE DESCRIBE THE ALLOCATION OF WORKING CAPITAL.

A. Working Capital was divided into cash, material and supplies and prepayments. Cash working capital is related to O&M expense and was allocated based upon the allocation of total O&M expense.

Materials and supplies were split between fuel stock, production, emissions and transmission and distribution. Fuel stock and emissions materials were allocated using the energy allocation factor. Production-related material and supplies were allocated using the production demand allocation factor and the transmission- and distribution-related materials and supplies were allocated using the allocation of transmission and distribution electric plant-in-service.

Prepayments were allocated using factors developed from gross plant relationships.

Q. PLEASE DESCRIBE THE ALLOCATION OF OTHER RATE BASE COMPONENTS.

A. Plant Held for Future Use is limited to a distribution component that was allocated using distribution electric plant-in-service. Construction Work-in-Progress was functionalized and allocated using appropriate related Electric Plant-in-Service factors. Accumulated Deferred Federal Income Tax Credits were allocated on Electric Plant-in-Service. Customer Deposits were assigned based on an analysis of accounting records and customer advances were allocated based on transmission and distribution plant-in-service.

Q. HOW WERE REVENUES DEVELOPED FOR EACH CLASS?

A. Sales revenues were directly assigned to each class.

Forfeited discounts were directly assigned based on an analysis of accounting records. Miscellaneous service revenue was allocated on distribution plant-in-service.

Rent from electric property and other electric revenue was functionalized and allocated to classes based on related functional allocators.

Q. PLEASE DESCRIBE THE ALLOCATION OF PRODUCTION OPERATION AND MAINTENANCE ("O&M") EXPENSE.

A. Production-related O&M was classified as either demand or energy related. The demand component was allocated using the production demand allocation factor and the energy component was allocated using the energy allocation factor. Demand-related system sales revenue was allocated based on the production demand allocation factor. Energy-related system sales revenue was allocated on the energy allocation factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF TRANSMISSION O&M.

A. Transmission-related O&M was broken down into three pieces: PJM OATT Transmission Owner ("TO") revenues, expenses incurred through PJM as a Load Serving Entity ("LSE") and the traditional transmission cost-of-service expenses recorded in FERC accounts 560 – 574. Revenues earned through PJM as a TO and the traditional transmission cost-of-service expenses are classified as transmission and allocated using the transmission demand allocation factor. Expenses incurred through PJM as a LSE are classified as production expenses and allocated using the production demand allocation factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF DISTRIBUTION O&M AMONG THE VARIOUS CUSTOMER CLASSES.

A. Distribution O&M expenses were functionalized and classified according to the associated distribution plant accounts and allocated accordingly. Accounts 581, Load Dispatching and 582, Station Expenses were allocated using the distribution demand allocation factor. Account 583 Overhead Line Expense was allocated based upon the same allocation used for plant account 365 Overhead Lines. Account 584 Underground Line Expense was allocated based upon the same allocation used for plant accounts 366 Underground Conduit and 367 Underground Lines. Account 585, Street Lighting Operation Expense, was classified as customer-related and directly assigned to the street lighting class. Meter Operation Expense, account 586, was classified customer-related and allocated in the same manner as meter plant. Account 587, Customer Installation Expense was classified as customer-related and allocated based on primary customers.

Accounts 588 and 589 were allocated on total distribution plant and classified accordingly. Account 580 was classified as demand- and customer-related and allocated using the allocated subtotal of accounts 581 through 589.

Accounts 591 and 592 were classified demand-related and allocated on the distribution demand allocation factor. Accounts 593, 594, and 595 were functionalized and classified according to the associated distribution plant accounts and allocated accordingly. Distribution maintenance account 596 was directly assigned to the street lighting class. Account 597 was classified customer-related and allocated in the same manner as meter plant. Account 598 was classified customer-related and directly assigned to the outdoor lighting class. Account 590 was classified and allocated based on the sum of the allocated O&M expense accounts 591 through 598.

Q. CAN YOU EXPLAIN HOW CUSTOMER ACCOUNTING (ACCOUNTS 901-905), CUSTOMER SERVICES (ACCOUNTS 907-910) AND SALES EXPENSE (ACCOUNTS 911-916) WERE ALLOCATED?

A. Account 902, Meter Reading Expense, was allocated to those classes with meter installations based upon an average number of customers weighted to reflect differences in meter reading requirements. Customer Records Expense, account 903, was divided into two categories of cost; call center and other. Call center costs were first split into residential and other based on the number of calls received and then other call center expenses were allocated based on the number of customers. The other category of expenses was allocated based on the number of customers. Account 904, Uncollectibles, was allocated based on the number of customers. Accounts 901 and 905 were allocated based on the sum of the allocated accounts 902, 903 and 904.

Accounts 907 through 916, Customer Service Expenses and Sales Expenses, were allocated based on the number of customers.

Q. PLEASE DESCRIBE THE ALLOCATION OF ADMINISTRATIVE AND GENERAL ("A&G") EXPENSE.

A. A&G expense, excluding regulatory expense, was functionalized and classified using O&M labor expense. The functionalized/classified cost was then allocated using the appropriate functional classification allocator. A&G regulatory expense was allocated to the customer classes based on sales revenue.

Q. PLEASE DESCRIBE THE ALLOCATION OF DEPRECIATION AND AMORTIZATION EXPENSE.

A. The functionalized components of depreciation and amortization expense were allocated using the corresponding plant items.

Q. PLEASE DESCRIBE HOW OTHER EXPENSES WERE ALLOCATED.

A. Other Expense items were allocated using the appropriate plant or demand allocator. The Gain on Disposition of Utility Plant was allocated based on distribution plant. Accretion was allocated on production demand. The Interest Income and Interest Expense items were allocated based on gross utility plant. Interest on Customer Deposits was allocated using the customer deposit allocator that was also used for the customer deposit rate base offset.

Q. HOW WERE TAXES ASSIGNED TO THE CUSTOMER CLASSES?

A. Individual tax items other than income taxes were allocated and classified using the appropriate revenue, labor or plant allocator.

Interest expense was allocated on rate base and individual Schedule M items were allocated using the appropriate allocators. State and current Federal income taxes were computed by class. Feedback of prior Investment Tax Credit Normalized was allocated based on gross utility plant and individual Deferred Federal Income Tax items were allocated using the appropriate allocation factors.

Q. PLEASE DESCRIBE THE ALLOCATION OF THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (“AFUDC”) OFFSET.

A. The AFUDC offset was split between the individual functionalized components. The production component was allocated using the production demand allocator. The transmission and distribution components were allocated using the corresponding plant allocators. The general plant component was allocated using the labor allocation factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF THE VARIOUS JURISDICITONAL ADJUSTMENTS.

A. The jurisdictional adjustments are identified in the various sections of the cost-of-service study to which they apply. Each adjustment was allocated using a method consistent with both the nature of the adjustment and the underlying line item being adjusted. For example, an adjustment to employee-related expenses would be allocated using the labor allocation factor but an adjustment for Big Sandy Plant O&M expenses would be allocated using the production demand allocation factor.

VII. REVENUE ALLOCATION

Q. WHAT IS THE RESULTING EARNED RATE OF RETURN FOR EACH CLASS SHOWN IN THE CLASS COST-OF-SERVICE STUDY?

A. The resulting earned rates of return are as follows:

CLASS	ROR
Residential	4.55 %
Small General Service	14.68 %
Medium General Service	15.60 %
Large General Service	11.88 %
Quantity Power	10.84 %
Commercial and Industrial Power - Time of Day	9.10 %
Municipal Waterworks	14.41 %
Outdoor Lighting	11.39 %
Street Lighting	17.03 %

CLASS	ROR
Total Kentucky Power Jurisdiction	7.89 %

Q. HOW ARE THESE RATES OF RETURN USED IN THIS PROCEEDING?

A. The earned rates of return for each class form the basis for the allocation of the revenue increase required for each class.

Q. PLEASE EXPLAIN THE PRINCIPLES OR GUIDELINES THAT YOU FOLLOWED IN ALLOCATING THE PROPOSED REVENUE INCREASE AMONG THE TARIFF CLASSES.

A. One key objective of ratemaking is to design rates such that they reflect as nearly as possible the actual costs of serving the customer. To fully meet this objective would require that the rates of return for all tariff classes be equalized. However, as discussed by Company Witness Wohnhas, the Company opted not to equalize returns across tariff classes.

Q. PLEASE DESCRIBE EXHIBIT JMS-3.

A. Exhibit JMS-3 is the calculation of the allocation of the proposed revenue increase to each class of customers. Page 1 is a summary of the calculation of the required sales revenue per class, net of the Transmission OATT adjustment. Page 2 of the exhibit calculates the current subsidies received by each class. Page 3, in Columns 2 through 11, shows the calculation of the required sales revenue for each class before adjusting to include each class' current subsidy.

Q. PLEASE DESCRIBE THE TRANSMISSION OATT ADJUSTMENT IDENTIFIED ON PAGE 1 OF JMS-3.

A. The $312,820 calculated in the Class Cost-of-Service Study and identified in Column 10 on page 1 of JMS-3, reflects the embedded cost of transmission net of the OATT revenues the Company receives from PJM as a transmission owner. These costs are removed from the required sales revenue because they will be recovered through the PJM OATT charges in base rates, as discussed by Company Witness Vaughan.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A**.** Yes, it does.

KENTUCKY POWER COMPANY
DEVELOPMENT OF ANNUALIZATION ADJUSTMENT
TEST YEAR ENDED SEPTEMBER 30, 2014

					Weather & Specific Customer Adjustments				After Specific Customer Adjustment			
Tariff	Year End Adjusted Number of Customers	Mar 2013 Number of Customers	Year End Adjusted Metered KWH	Year End Migration Revenue	Number of Customers	Mar 2013 Number of Customers	Metered KWH	Revenue	Year End Adjusted Number of Customers	Mar 2013 Number of Customers	Year End Adjusted Metered KWH	Year End Migration Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(2)+(6)	(11)=(3)+(7)	(12)=(4)+(8)	(13)=(5)+(9)
RS Total	1,669,972	138,125	2,336,196,169	$231,803,910	0	0	(63,344,127)	($5,917,595)	1,669,972	138,125	2,272,852,042	$225,886,315
RSLMTOD Total	2,085	172	4,412,208	$396,225	0	0	(143,457)	($11,536)	2,085	172	4,268,751	$384,689
RS TOD Total	36	3	46,491	$4,289					36	3	46,491	$4,289
OL	761,070	55,952	42,655,897	$7,956,803					761,070	55,952	42,655,897	$7,956,803
SGS Metered Total	270,382	22,622	137,657,496	$18,239,353					270,382	22,622	137,657,496	$18,239,353
SGSLMTOD (225)	12	1	3,012	$528					12	1	3,012	$528
SGS NM Total	13,411	1,124	3,961,264	$629,848					13,411	1,124	3,961,264	$629,848
SGS TOD (227)	923	76	369,750	$54,076					923	76	369,750	$54,076
MGS RL (214)	908	77	1,536,074	$164,225					908	77	1,536,074	$164,225
MGS Sec Total	83,732	7,004	494,884,637	$55,909,224	(7)	0	0	($160)	83,725	7,004	494,884,637	$55,909,064
MGSLMTOD (223)	555	46	1,060,745	$107,154					555	46	1,060,745	$107,154
MGSTOD (229)	905	76	3,836,888	$378,348					905	76	3,836,888	$378,348
MGS Pri Total	1,055	84	9,728,413	$1,035,270	(7)	0	0	($237)	1,048	84	9,728,413	$1,035,034
MGS Sub (236)	124	10	1,041,361	$122,264	0	0	0	$0	124	10	1,041,361	$122,264
LGS Sec Total	8,961	747	552,274,983	$55,324,875	12	1	6,360,000	$571,496	8,973	748	558,634,983	$55,896,371
LGSLMTOD (251)	108	9	1,959,939	$193,121					108	9	1,959,939	$193,121
LGS Pri	879	75	89,724,698	$8,186,301	36	3	19,944,000	$1,599,865	915	78	109,668,698	$9,786,166
LGS Sub (248)	261	20	36,676,149	$2,646,442	0	0	0	$0	261	20	36,676,149	$2,646,442
LGS Tran (250)	12	1	672,426	$67,113	0		0	$0	12	1	672,426	$67,113
QP Sec (356)	75	6	23,355,352	$1,972,823					75	6	23,355,352	$1,972,823
QP Pri	480	40	331,170,851	$24,295,105	0	0	0	$0	480	40	331,170,851	$24,295,105
QP Sub (359)	314	26	344,605,816	$22,834,308	0	0	0	$0	314	26	344,605,816	$22,834,308
QP Tran (360)	55	5	60,749,991	$3,616,522	0	0	0	$0	55	5	60,749,991	$3,616,522
CIP Sub (371)	107	9	1,744,959,841	$98,063,673	0	0	2,760,000	$149,456	107	9	1,747,719,841	$98,213,129
CIP Tran (372)	26	2	316,710,702	$17,507,511	0	0	0	$0	26	2	316,710,702	$17,507,511
SL	144,903	11,958	8,537,689	$1,428,283					144,903	11,958	8,537,689	$1,428,283
MW (540)	132	11	3,864,039	$354,484					132	11	3,864,039	$354,484
Total	2,961,483	238,280	6,552,652,881	$553,292,078	34	4	(34,423,584)	($3,608,711)	2,961,517	238,284	6,518,229,297	$549,683,368

KENTUCKY POWER COMPANY
DEVELOPMENT OF ANNUALIZATION ADJUSTMENT
TEST YEAR ENDED SEPTEMBER 30, 2014

Tariff (1)	Year End Adjusted Number of Customers * (2)	Mar 2013 Annual Average Number of Customers (3)	Mar 2013 Number of Customers * (4)	Customer Growth (5)=(4)-(3)	Year End Adjusted Metered KWH * (6)	TME Mar 2013 Average KWH Per Customer (7)=(6)/(3)	KWH Annualization Adjustment (8)=(5)x(7)	Year End Migration Revenue * (9)	TME Mar 2013 Average Revenue Per KWH (10)=(9)/(6)	Revenue Annualization Adjustment ** (11)=(8)x(10)
RS Total	1,669,972	139,164.333	138,125	(1,039.333)	2,272,852,042	16,332	(16,974,543)	$225,886,315	$0.09938	($1,687,011)
RSLMTOD Total	2,085	173.750	172	(1.750)	4,268,751	24,568	(42,995)	$384,689	$0.09012	($3,878)
RS TOD Total	36	3.000	3	0.000	46,491	15,497	0	$4,289	$0.09225	$0
OL	761,070	63,422.469	55,952	(7,470.579)	42,655,897	673	(5,015,299)	$7,956,803	$0.18653	($938,247)
SGS Metered Total	270,382	22,531.833	22,622	90.167	137,657,496	6,109	550,870	$18,239,353	$0.13250	$72,984
SGSLMTOD (225)	12	1.000	1	0.000	3,012	3,012	0	$528	$0.17537	$0
SGS NM Total	13,411	1,117.583	1,124	6.417	3,961,264	3,544	22,744	$629,848	$0.15900	$3,613
SGS TOD (227)	923	76.917	76	(0.917)	369,750	4,807	(4,407)	$54,076	$0.14625	($644)
MGS RL (214)	908	75.667	77	1.333	1,536,074	20,301	27,067	$164,225	$0.10691	$2,899
MGS Sec Total	83,725	6,977.083	7,004	26.917	494,884,637	70,930	1,909,200	$55,909,064	$0.11297	$215,372
MGSLMTOD (223)	555	46.250	46	(0.250)	1,060,745	22,935	(5,734)	$107,154	$0.10102	($579)
MGSTOD (229)	905	75.417	76	0.583	3,836,888	50,876	29,678	$378,348	$0.09861	$2,926
MGS Pri Total	1,048	87.333	84	(3.333)	9,728,413	111,394	(371,313)	$1,035,034	$0.10639	($39,507)
MGS Sub (236)	124	10.333	10	(0.333)	1,041,361	100,777	(33,592)	$122,264	$0.11741	($4,014)
LGS Sec Total	8,973	747.750	748	0.250	558,634,983	747,088	186,772	$55,896,371	$0.10006	$28,052
LGSLMTOD (251)	108	9.000	9	0.000	1,959,939	217,771	0	$193,121	$0.09853	$8
LGS Pri	915	76.250	78	1.750	109,668,698	1,438,278	2,516,987	$9,786,166	$0.08923	$211,456
LGS Sub (248)	261	21.750	20	(1.750)	36,676,149	1,686,260	(2,950,955)	$2,646,442	$0.07216	($212,804)
LGS Tran (250)	12	1.000	1	0.000	672,426	672,426	0	$67,113	$0.09981	($0)
QP Sec (356)	75	6.250	6	(0.250)	23,355,352	3,736,856	(934,214)	$1,972,823	$0.08447	($78,947)
QP Pri	480	40.000	40	0.000	331,170,851	8,279,271	0	$24,295,105	$0.07336	($35)
QP Sub (359)	314	26.167	26	(0.167)	344,605,816	13,169,649	(2,194,942)	$22,834,308	$0.06626	($145,516)
QP Tran (360)	55	4.583	5	0.417	60,749,991	13,254,543	5,522,726	$3,616,522	$0.05953	$328,666
CIP Sub (371)	107	8.917	9	0.083	1,747,719,841	196,005,963	16,333,830	$98,213,129	$0.05620	$924,647
CIP Tran (372)	26	2.167	2	(0.167)	316,710,702	146,174,170	(24,362,362)	$17,507,511	$0.05528	($1,346,730)
SL	144,903	12,075.258	11,958	(117.753)	8,537,689	707	(347,607)	$1,428,283	$0.16729	($52,535)
MW (540)	132	11.000	11	0.000	3,864,039	351,276	0	$354,484	$0.09174	$2
Total	2,961,517	246,793.061	238,284	(8,508.666)	6,518,229,297	26,412	(26,138,089)	$549,683,368		($2,719,824)

* After Specific Customer Adjustment

** Values may not calculate due to rounding and calculation by lamp instead of customer for lighting.

KENTUCKY POWER COMPANY
DEVELOPMENT OF OPERATING RATIO
TWELVE MONTHS ENDED SEPTEMBER 30, 2014

Line No.	Description	Amount
	Operating Revenues	
1	Sales of Electricity	$ 567,450,376
2	ATR Over/Under Collection	(3,615,459)
3	Capacity Charge Revenues Rockport Unit Power Agreement	(5,719,970)
4	Customer Migration Adjustment	79,107
5	System Sales Revenue Adjustment	(2,486,806)
6	Environmental Surcharge Adjustment	2,812,947
7	Revenue Out of Period Adjustment	70,659
8	Fuel Under (Over) Revenues	(5,298,776)
9	Total	$ 553,292,078
	Operating Expenses	
10	Total Adjusted O&M	$348,652,947
11	Less: Customer Annualization O&M Effect	($3,787,763)
12	Subtotal	$352,440,710
13	Total O&M Labor	$31,455,751
14	Big Sandy O&M Adjustment - Labor	($9,228,205)
15	Incentive Compensation Plan Adjustment	($973,508)
16	Annualization of Employee Related Expenses	$29,576
17	Subtotal	$21,283,614
18	Adjusted O&M Less Labor Expense	$331,157,096
19	Operating Ratio	59.85%

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Rate Base													
P-T-D Plant in Service													
Production Plant	1,562,785,754	PROD_DEMAND	TOTAL	1,562,785,754	734,427,704	32,171,380	123,569,428	164,472,393	150,217,616	356,613,780	713,215	488,611	111,628
Transmission													
GSU	11,074,145	PROD_DEMAND	TOTAL	11,074,145	5,204,270	227,971	875,632	1,165,477	1,064,466	2,527,021	5,054	3,462	791
All Other Transmission Plant	504,481,253	TRANS_TOTAL	TOTAL	504,481,253	235,621,832	10,267,444	39,464,377	52,846,079	48,717,857	117,179,997	229,626	125,394	28,647
Total	515,555,398		TOTAL	515,555,398	240,826,102	10,495,416	40,340,009	54,011,557	49,782,323	119,707,018	234,680	128,856	29,438
Distribution													
360 Land and Land Rights	7,494,757	DIST_CPD	TOTAL	7,494,757	5,049,924	213,800	786,216	1,007,155	432,840	-	4,822	-	-
361 Structures and Improvements	4,327,099	DIST_CPD	TOTAL	4,327,099	2,915,574	123,437	453,922	581,481	249,900	-	2,784	-	-
362 Station Equipment	89,173,211	DIST_CPD	TOTAL	89,173,211	60,084,396	2,543,806	9,354,460	11,983,208	5,149,964	-	57,376	-	-
363 Storage Battery Equipment	-	DIST_POLES	TOTAL	-	-	-	-	-	-	-	-	-	-
364 Poles	184,542,178	DIST_POLES	TOTAL	184,542,178	129,901,350	6,240,393	19,201,631	21,956,836	6,226,144	-	106,060	749,280	160,484
365 Overhead Lines	188,359,442	DIST_OHLINES	TOTAL	188,359,442	128,667,172	5,680,864	19,709,751	24,416,219	9,481,508	-	117,200	236,148	50,579
366 Underground Conduit	6,761,885	DIST_UGLINES	TOTAL	6,761,885	4,682,628	215,110	705,757	843,977	289,643	-	4,062	17,055	3,653
367 Underground Lines	10,089,373	DIST_UGLINES	TOTAL	10,089,373	6,986,924	320,964	1,053,057	1,259,294	432,175	-	6,061	25,448	5,451
368 Transformers	122,321,623	DIST_TRANSF	TOTAL	122,321,623	88,722,285	4,596,248	12,653,491	13,214,693	2,038,901	-	64,327	849,688	181,990
369 Services	55,320,557	DIST_SERV	TOTAL	55,320,557	35,142,475	6,053,501	1,830,305	192,102	1,525	-	2,795	12,083,624	14,230
370 Meters	24,511,141	DIST_METERS	TOTAL	24,511,141	10,488,030	6,117,105	3,445,905	2,319,363	1,503,990	633,924	2,825	-	-
371 Installations on Cust Premises	19,972,766	DIST_OL	TOTAL	19,972,766	-	-	-	-	-	-	-	19,972,766	-
373 Street Lighting	3,425,848	DIST_SL	TOTAL	3,425,848	-	-	-	-	-	-	-	-	3,425,848
Total	716,299,880		TOTAL	716,299,880	472,640,758	32,105,228	69,194,496	77,774,329	25,806,588	633,924	368,313	33,934,010	3,842,234
Total P-T-D Plant in Service	2,794,641,032		TOTAL	2,794,641,032	1,447,894,564	74,772,024	233,103,933	296,258,279	225,806,527	476,954,722	1,316,208	34,551,477	3,983,301
General & Intangible Plant	55,768,593	LABOR_M	TOTAL	55,768,593	32,016,116	1,985,365	4,724,084	5,719,550	3,731,275	6,772,104	26,444	653,356	140,300
HR - J 765 Line - AFUDC	691,966	BULK_TRANS	TOTAL	691,966	325,188	14,245	54,714	72,825	66,513	157,900	316	216	49
Asset Retirement Obligation (ARO)	(59,067,552)	PROD_DEMAND	TOTAL	(59,067,552)	(27,758,665)	(1,215,960)	(4,670,470)	(6,216,451)	(5,677,673)	(13,478,689)	(26,957)	(18,468)	(4,219)
Total Electric Plant in Service	2,792,034,039		TOTAL	2,792,034,039	1,452,477,202	75,555,674	233,212,260	295,834,202	223,926,642	470,406,037	1,316,011	35,186,581	4,119,431
Move FGD from Base Rates to Environmental (Mitchell)	(322,612,704)	PROD_DEMAND	TOTAL	(322,612,704)	(151,611,126)	(6,641,279)	(25,508,978)	(33,952,756)	(31,010,080)	(73,617,344)	(147,232)	(100,866)	(23,044)
Removal of Coal Related Assets - Production	(452,571,576)	PROD_DEMAND	TOTAL	(452,571,576)	(212,685,010)	(9,316,601)	(35,784,822)	(47,630,029)	(43,501,947)	(103,272,800)	(206,542)	(141,498)	(32,327)
Removal of Coal Related Assets - GSU	(1,018,664)	PROD_DEMAND	TOTAL	(1,018,664)	(478,719)	(20,970)	(80,546)	(107,207)	(97,916)	(232,450)	(465)	(318)	(73)
Total Adjustments to Electric Plant in Service	(776,202,944)		TOTAL	(776,202,944)	(364,774,854)	(15,978,850)	(61,374,346)	(81,689,992)	(74,609,943)	(177,122,594)	(354,239)	(242,683)	(55,443)
Total Adjusted Electric Plant in Service	2,015,831,095		TOTAL	2,015,831,095	1,087,702,348	59,576,823	171,837,914	214,144,210	149,316,699	293,283,444	961,772	34,943,898	4,063,988
Depreciation Reserve													
Generation	(630,803,459)	RB_GUP_EPIS_P	TOTAL	(630,803,459)	(296,444,688)	(12,985,668)	(49,877,613)	(66,387,702)	(60,633,898)	(143,943,727)	(287,882)	(197,223)	(45,058)
Transmission - GSU	(5,698,478)	RB_GUP_EPIS_P	TOTAL	(5,698,478)	(2,677,987)	(117,308)	(450,579)	(599,725)	(547,747)	(1,300,342)	(2,601)	(1,782)	(407)
Transmission - All Other	(160,716,770)	RB_GUP_EPIS_T	TOTAL	(160,716,770)	(75,073,975)	(3,271,791)	(12,575,401)	(16,837,304)	(15,518,903)	(37,316,892)	(73,158)	(40,169)	(9,177)
Distribution	(195,091,920)	RB_GUP_EPIS_D	TOTAL	(195,091,920)	(128,728,757)	(8,744,202)	(18,845,860)	(21,182,669)	(7,028,700)	(172,656)	(100,314)	(9,242,290)	(1,046,473)
General	(15,699,391)	RB_GUP_EPIS_G	TOTAL	(15,699,391)	(9,012,842)	(558,899)	(1,329,875)	(1,610,108)	(1,050,390)	(1,906,412)	(7,444)	(183,926)	(39,496)
HR-J Post In-Service AFUDC	(982,717)	BULK_TRANS	TOTAL	(982,717)	(461,826)	(20,230)	(77,703)	(103,424)	(94,460)	(224,247)	(448)	(307)	(70)
Total Depreciation Reserve	(1,008,992,735)		TOTAL	(1,008,992,735)	(512,400,075)	(25,698,098)	(83,157,030)	(106,720,932)	(84,874,098)	(184,864,276)	(471,848)	(9,665,697)	(1,140,681)
Cost of Removal Adjustment	(69,695)	PROD_DEMAND	TOTAL	(69,695)	(32,753)	(1,435)	(5,511)	(7,335)	(6,699)	(15,904)	(32)	(22)	(5)
Move FGD from Base Rates to Environmental (Mitchell)	75,047,400	PROD_DEMAND	TOTAL	75,047,400	35,268,359	1,544,920	5,933,996	7,898,220	7,213,683	17,125,148	34,250	23,464	5,361
Removal of Coal Related Assets - Production	247,884,800	PROD_DEMAND	TOTAL	247,884,800	116,492,913	5,102,936	19,600,245	26,088,161	23,827,107	56,565,102	113,128	77,502	17,706
Removal of Coal Related Assets - GSU	431,899	PROD_DEMAND	TOTAL	431,899	202,970	8,891	34,150	45,454	41,515	98,556	197	135	31
Removal of Big Sandy CWIP from Rate Base	(3,720,953)	PROD_DEMAND	TOTAL	(3,720,953)	(1,748,654)	(76,599)	(294,216)	(391,605)	(357,664)	(849,088)	(1,698)	(1,163)	(266)
Adj to Incl Test Year Mitchell Plant O&M and Rate Base	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Removal of Big Sandy Depreciation	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Remove RTO Amortization	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-	-
Remove Mitchell ARO from Rate Base	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Depreciation Adjustments	319,573,451		TOTAL	319,573,451	150,182,835	6,578,713	25,268,664	33,632,896	30,717,942	72,923,813	145,845	99,916	22,827
Total Adjusted Depreciation Reserve	(689,419,284)		TOTAL	(689,419,284)	(362,217,240)	(19,119,386)	(57,888,366)	(73,088,036)	(54,156,156)	(111,940,463)	(326,003)	(9,565,781)	(1,117,854)
Net Electric Plant in Service	1,326,411,811		TOTAL	1,326,411,811	725,485,108	40,457,438	113,949,548	141,056,173	95,160,543	181,342,980	635,769	25,378,117	2,946,133
Plant Held for Future Use - Tranmsission		RB_GUP_EPIS_T	TOTAL	-	-	-	-	-	-	-	-	-	-
Plant Held for Future Use - Distribution	626,976	RB_GUP_EPIS_D	TOTAL	626,976	413,702	28,102	60,566	68,076	22,588	555	322	29,702	3,363

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Total Plant Held for Future Use	626,976		TOTAL	626,976	413,702	28,102	60,566	68,076	22,588	555	322	29,702	3,363
Working Capital													
Working Capital - Cash													
Working Capital Cash - Excl Sys Sales	41,470,569	EXP_OM	TOTAL	41,470,569	18,865,396	1,105,428	3,412,729	4,445,158	3,915,459	9,367,895	22,198	272,131	64,174
System Sales Add Back - Demand	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
System Sales Add Back - Energy	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Working Capital - Cash	41,470,569		TOTAL	41,470,569	18,865,396	1,105,428	3,412,729	4,445,158	3,915,459	9,367,895	22,198	272,131	64,174
Cash Working Captial Adjustments													
Weather Normalization Adjustment	(443,589)	WEATHER_FXNL	TOTAL	(443,589)	(443,589)	-	-	-	-	-	-	-	-
Customer Annualization Adjustment	(29,882)	REVYEC_EXP_OM	TOTAL	(29,882)	(126,507)	5,682	13,220	164,453	7,794	(20,397)	0	(70,197)	(3,931)
Removal of AEP Pool Cost	(1,310,105)	PROD_DEMAND	TOTAL	(1,310,105)	(615,681)	(26,970)	(103,590)	(137,879)	(125,930)	(298,954)	(598)	(410)	(94)
System Sales Margins	7,590,356	PROD_ENERGY	TOTAL	7,590,356	2,697,169	170,181	612,690	837,911	873,774	2,339,276	4,614	44,958	9,782
Interest on Customer Deposits	(303)	CUST_DEP_FXNL	TOTAL	(303)	(221)	(13)	(34)	(18)	(15)	-	-	(1)	-
Normalization of Major Storms	(80,970)	TDOMX	TOTAL	(80,970)	(49,360)	(2,664)	(7,705)	(9,337)	(4,782)	(5,969)	(43)	(779)	(331)
Amortization of Storm Cost Deferral	(279,684)	EXP_OM_DIST	TOTAL	(279,684)	(188,907)	(10,823)	(28,764)	(33,599)	(11,651)	(200)	(159)	(3,912)	(1,668)
Rate Case Expense	32,255	EXP_OM_AG_REG	TOTAL	32,255	13,537	1,103	3,365	3,872	3,073	6,737	21	464	83
Postage Rate Increase	1,527	CUST_TOTAL	TOTAL	1,527	969	167	51	6	1	0	0	333	0
Eliminate Advertising Expense	(3,826)	EXP_OM_CUSTSERV	TOTAL	(3,826)	(2,427)	(418)	(128)	(15)	(1)	(0)	(0)	(835)	(1)
Annualization of Lease Costs	9,122	TDOMX	TOTAL	9,122	5,561	300	868	1,052	539	672	5	88	37
Reliability Adjustment	1,331,988	TOTOHLINES	TOTAL	1,331,988	923,595	42,582	138,990	165,642	56,107	-	797	3,520	754
Pension & OPEB Expense Adjustment	(25,823)	LABOR_M	TOTAL	(25,823)	(14,825)	(919)	(2,187)	(2,648)	(1,728)	(3,136)	(12)	(303)	(65)
Amortization of Deferred IGCC Costs	6,563	PROD_DEMAND	TOTAL	6,563	3,084	135	519	691	631	1,498	3	2	0
Amortization of Deferred CCS FEED Study Costs	4,303	PROD_DEMAND	TOTAL	4,303	2,022	89	340	453	414	982	2	1	0
Amortization of Deferred CARRS Site Costs	12,916	PROD_DEMAND	TOTAL	12,916	6,070	266	1,021	1,359	1,242	2,947	6	4	1
Amortization of Deferred Preliminary Big Sandy FGD Costs	138,162	PROD_DEMAND	TOTAL	138,162	64,929	2,844	10,924	14,541	13,280	31,527	63	43	10
Incentive Compensation Plan Adjustment	(121,689)	LABOR_M	TOTAL	(121,689)	(69,860)	(4,332)	(10,308)	(12,480)	(8,142)	(14,777)	(58)	(1,426)	(306)
Annualize T&D Employee-Related Expenses	3,697	LABOR_TD	TOTAL	3,697	2,412	136	370	438	177	97	2	46	20
Removal of Big Sandy O&M	(5,339,667)	PROD_DEMAND	TOTAL	(5,339,667)	(2,509,365)	(109,922)	(422,207)	(561,963)	(513,258)	(1,218,464)	(2,437)	(1,669)	(381)
PJM Charges & Credits - Pool Term & Removal of Big Sandy	948,038	PROD_DEMAND	TOTAL	948,038	445,528	19,516	74,961	99,774	91,127	216,334	433	296	68
Adjustments to Include Test Year Mitchell Plant O&M	1,104,981	PROD_DEMAND	TOTAL	1,104,981	519,283	22,747	87,371	116,292	106,213	252,147	504	345	79
Mitchell Plant Maintenance Normalization	402,976	PROD_DEMAND	TOTAL	402,976	189,378	8,296	31,863	42,410	38,735	91,956	184	126	29
Eliminate Mitchell O&M FGD	(1,859,919)	PROD_DEMAND	TOTAL	(1,859,919)	(874,065)	(38,288)	(147,064)	(195,744)	(178,779)	(424,417)	(849)	(582)	(133)
Cost of Removal Adjustment	8,712	PROD_DEMAND	TOTAL	8,712	4,094	179	689	917	837	1,988	4	3	1
Mitchell Plant Incentive Compensation Adjustment	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-	-
Mitchell Plant Maintenance	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Mitchell Plant Annualization of Employee-Related Exp	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-	-
Removal of Mitchell Severance Costs	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-	-
Removal of Mitchell Repositioning Study Costs	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-	-
Adj to Incl TY Mitchell Plant O&M and Rate Base - Demand	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Adj to Incl TY Mitchell Plant O&M and Rate Base - Energy	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
PJM - Pool Term & Mitchell Xfer - Prod Demand	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
PJM Charges & Credits - Pool Term & Mitchell Xfer - Energy	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
Amortization of Big Sandy Depreciation & O&M	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Not Used	-	CUST_DEP_FXNL	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Cash Working Capital Adjustments	2,100,139		TOTAL	2,100,139	(17,175)	79,874	255,256	496,127	349,657	959,846	2,481	(29,883)	3,955
Working Capital - Materials & Supplies													
Fuel	35,326,091	PROD_ENERGY	TOTAL	35,326,091	12,552,831	792,036	2,851,507	3,899,702	4,066,612	10,887,166	21,472	209,238	45,528
Production	15,844,495	PROD_DEMAND	TOTAL	15,844,495	7,446,085	326,173	1,252,824	1,667,524	1,523,000	3,615,573	7,231	4,954	1,132
Emissions	16,155,106	PROD_ENERGY	TOTAL	16,155,106	5,740,582	362,209	1,304,033	1,783,387	1,859,717	4,978,850	9,819	95,688	20,821
Transmission & Distribution	3,033,544	TDPLANT	TOTAL	3,033,544	1,756,784	104,884	269,721	324,531	186,203	296,572	1,485	83,836	9,529
Total Working Cap - Materials & Supplies	70,359,236		TOTAL	70,359,236	27,496,282	1,585,302	5,678,085	7,675,143	7,635,532	19,778,160	40,007	393,716	77,010
Working Captial - Materials & Supplies Adjustments													
Big Sandy Coal Stock Adjustment	(18,709,274)	PROD_ENERGY	TOTAL	(18,709,274)	(6,648,184)	(419,475)	(1,510,205)	(2,065,346)	(2,153,744)	(5,766,021)	(11,372)	(110,816)	(24,112)
Mitchell Coal Stock Adjustment	664,080	PROD_ENERGY	TOTAL	664,080	235,975	14,889	53,604	73,309	76,446	204,663	404	3,933	856
Removal of Big Sandy M&S from Rate Base	(6,268,345)	PROD_DEMAND	TOTAL	(6,268,345)	(2,945,795)	(129,040)	(495,638)	(659,700)	(602,524)	(1,430,380)	(2,861)	(1,960)	(448)
Total Working Cap - Materials & Supplies Adjustments	(24,313,539)		TOTAL	(24,313,539)	(9,358,004)	(533,625)	(1,952,238)	(2,651,737)	(2,679,821)	(6,991,738)	(13,829)	(108,843)	(23,704)
Working Capital - Prepayments													
Working Capital - Prepayments	2,476,841	RB_GUP_EPIS	TOTAL	2,476,841	1,288,507	67,026	206,885	262,437	198,648	417,302	1,167	31,214	3,654
Pension & OPEB Expense Adjustment	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Working Capital	92,093,246		TOTAL	92,093,246	38,275,007	2,304,005	7,600,716	10,227,129	9,419,474	23,531,465	52,026	558,336	125,089

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Construction Work-In-Progress													
Production	31,948,245	RB_GUP_EPIS_P	TOTAL	31,948,245	15,014,007	657,684	2,526,147	3,362,332	3,070,919	7,290,305	14,580	9,989	2,282
Transmission	37,203,205	RB_GUP_EPIS_T	TOTAL	37,203,205	17,378,351	757,364	2,910,992	3,897,550	3,592,363	8,638,227	16,935	9,298	2,124
Distribution	8,754,012	RB_GUP_EPIS_D	TOTAL	8,754,012	5,776,216	392,363	845,637	950,492	315,386	7,747	4,501	414,713	46,957
General	1,279,089	RB_GUP_EPIS_G	TOTAL	1,279,089	734,310	45,536	108,350	131,182	85,579	155,323	607	14,985	3,218
Total CWIP	79,184,551		TOTAL	79,184,551	38,902,885	1,852,947	6,391,125	8,341,556	7,064,248	16,091,602	36,623	448,985	54,581
Removal of Big Sandy CWIP from Rate Base	(1,584,601)	PROD_DEMAND	TOTAL	(1,584,601)	(744,680)	(32,620)	(125,294)	(166,768)	(152,315)	(361,592)	(723)	(495)	(113)
Total Adjusted CWIP	77,599,950		TOTAL	77,599,950	38,158,205	1,820,326	6,265,831	8,174,787	6,911,933	15,730,010	35,900	448,490	54,468
Rate Base Offsets													
Accumulated Deferred FIT	(394,858,880)	RB_GUP	TOTAL	(394,858,880)	(205,414,230)	(10,685,338)	(32,981,665)	(41,837,872)	(31,668,462)	(66,526,410)	(186,115)	(4,976,205)	(582,584)
Customer Advances	(117,511)	TDPLANT	TOTAL	(117,511)	(68,053)	(4,063)	(10,448)	(12,571)	(7,213)	(11,488)	(58)	(3,248)	(369)
Customer Deposits	(25,260,450)	CUST_DEP_FXNL	TOTAL	(25,260,450)	(18,426,047)	(1,109,246)	(2,826,995)	(1,511,957)	(1,262,649)	-	-	(123,557)	-
KY Over/Under Deferred Fuel Net of Tax	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
Adjustments to Rate Base Offsets													
ADFIT - FGD Movement from Base Rates to Environmental	24,400,898	PROD_DEMAND	TOTAL	24,400,898	11,467,148	502,315	1,929,378	2,568,026	2,345,456	5,568,067	11,136	7,629	1,743
ADFIT - Removal of Coal Related Assets	57,290,476	PROD_DEMAND	TOTAL	57,290,476	26,923,532	1,179,377	4,529,956	6,029,426	5,506,858	13,073,176	26,146	17,912	4,092
Total Adjustments to Rate Base Offsets	81,691,374		TOTAL	81,691,374	38,390,680	1,681,692	6,459,335	8,597,452	7,852,313	18,641,243	37,282	25,541	5,835
Total Rate Base Offsets	(338,545,467)		TOTAL	(338,545,467)	(185,517,649)	(10,116,955)	(29,359,774)	(34,764,947)	(25,086,010)	(47,896,655)	(148,890)	(5,077,468)	(577,118)
Total Rate Base	1,158,186,516		TOTAL	1,158,186,516	616,814,372	34,492,915	98,516,888	124,761,218	86,428,529	172,708,356	575,126	21,337,177	2,551,935
Operating Revenues													
Year End Migration Revenue	553,292,078	REVSALES_FXNL	TOTAL	553,292,078	232,204,424	18,923,805	57,716,485	66,417,851	52,718,758	115,571,184	354,484	7,956,803	1,428,283
Weather Normalization Adjustment	(5,929,131)	WEATHER_FXNL	TOTAL	(5,929,131)	(5,929,131)	-	-	-	-	-	-	-	-
Total Revenue Year End Customers	(399,400)	REVYEC_FXNL	TOTAL	(399,400)	(1,690,881)	75,952	176,699	2,198,063	104,167	(272,626)	2	(938,242)	(52,535)
Annualize Asset Transfer Rider	10,014,069	ATR_ADJ	TOTAL	10,014,069	4,082,297	449,721	1,311,063	1,435,466	958,049	1,561,077	7,199	174,693	34,504
Asset Transfer Rider Over/Under Collection Revenues	3,615,459	ATR_ADJ	TOTAL	3,615,459	1,473,864	162,366	473,344	518,258	345,892	563,608	2,599	63,071	12,457
Sales of Electricity	560,593,075		TOTAL	560,593,075	230,140,574	19,611,844	59,677,591	70,569,638	54,126,867	117,423,244	364,284	7,256,325	1,422,710
Other Operating Revenues													
Forfeited Discounts	3,643,764	FORF_DISC_FXNL	TOTAL	3,643,764	2,591,161	241,249	455,980	186,672	116,792	31,244	-	20,666	-
Miscellaneous Service Revenue	385,609	RB_GUP_EPIS_D	TOTAL	385,609	254,439	17,283	37,250	41,869	13,893	341	198	18,268	2,068
Rent from Electric Prop - Poles	4,838,578	DIST_POLES	TOTAL	4,838,578	3,405,930	163,619	503,454	575,694	163,246	-	2,781	19,646	4,208
Rent from Electric Prop - Other Dist	871,267	RB_GUP_EPIS_D	TOTAL	871,267	574,894	39,051	84,164	94,600	31,390	771	448	41,275	4,673
Other Electric Revenue - Dist	268,471	RB_GUP_EPIS_D	TOTAL	268,471	177,147	12,033	25,934	29,150	9,672	238	138	12,719	1,440
Other Electric Revenue - Wheeling	(367,524)	TRANS_TOTAL	TOTAL	(367,524)	(171,655)	(7,480)	(28,751)	(38,499)	(35,492)	(85,368)	(167)	(91)	(21)
Other Electric Revenues - Production	114,517	PROD_ENERGY	TOTAL	114,517	40,693	2,568	9,244	12,642	13,183	35,293	70	678	148
Total Other Operating Revenues	9,754,682		TOTAL	9,754,682	6,872,609	468,323	1,087,276	902,128	312,683	(17,481)	3,467	113,160	12,516
Eliminate Non-Recurring CATV Revenues	-	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-	-	-
Misc. Service Charges Adjustement	251,903	RB_GUP_EPIS_D	TOTAL	251,903	166,215	11,291	24,334	27,351	9,075	223	130	11,934	1,351
Annualization of CATV Revenues	-	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-	-	-
Customer Migration Adjustment	-	REVSALES_FXNL	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Other Operating Revenue Adjustments	251,903		TOTAL	251,903	166,215	11,291	24,334	27,351	9,075	223	130	11,934	1,351
Total Other Operating Revenues	10,006,585		TOTAL	10,006,585	7,038,824	479,614	1,111,610	929,479	321,758	(17,258)	3,597	125,094	13,868
Total Operating Revenues	570,599,660		TOTAL	570,599,660	237,179,398	20,091,458	60,789,201	71,499,116	54,448,625	117,405,986	367,881	7,381,419	1,436,577
Operating Expense													
O&M Expense													
Production													
Demand	42,692,815	PROD_DEMAND	TOTAL	42,692,815	20,063,394	878,871	3,375,720	4,493,124	4,103,706	9,742,120	19,484	13,348	3,049
Energy	9,521,335	PROD_ENERGY	TOTAL	9,521,335	3,383,327	213,475	768,558	1,051,075	1,096,062	2,934,385	5,787	56,395	12,271
Fuel	224,998,058	PROD_ENERGY	TOTAL	224,998,058	79,951,177	5,044,613	18,161,747	24,837,883	25,900,962	69,342,264	136,759	1,332,676	289,977
System Sales - Demand	(519,481)	PROD_DEMAND	TOTAL	(519,481)	(244,129)	(10,694)	(41,075)	(54,672)	(49,933)	(118,541)	(237)	(162)	(37)
System Sales - Energy	(219,455,800)	PROD_ENERGY	TOTAL	(219,455,800)	(77,981,782)	(4,920,352)	(17,714,378)	(24,226,064)	(25,262,957)	(67,634,193)	(133,390)	(1,299,849)	(282,834)
Purchased Power - Demand	58,873,831	PROD_DEMAND	TOTAL	58,873,831	27,667,626	1,211,972	4,655,152	6,196,064	5,659,052	13,434,483	26,869	18,407	4,205
Purchased Power - Energy	142,992,441	PROD_ENERGY	TOTAL	142,992,441	50,811,167	3,205,990	11,542,289	15,785,156	16,460,772	44,068,912	86,914	846,952	184,289
System Control	413,324	PROD_DEMAND	TOTAL	413,324	194,241	8,509	32,682	43,499	39,729	94,317	189	129	30
Total Production Expenses	479,491,804		TOTAL	479,491,804	182,070,932	10,563,430	38,536,147	52,406,800	53,260,283	139,616,482	276,001	2,267,908	493,821
Transmission Agreement Expenses - Production	37,859,264	PROD_DEMAND	TOTAL	37,859,264	17,791,877	779,368	2,993,531	3,984,426	3,639,097	8,639,147	17,278	11,837	2,704

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Transmission Agreement Expenses - Transmission	(57,542,217)	TRANS_TOTAL	TOTAL	(57,542,217)	(26,875,533)	(1,171,127)	(4,501,392)	(6,027,738)	(5,556,864)	(13,365,803)	(26,192)	(14,303)	(3,268)
Total Transmission Agreement Expenses	(19,682,953)		TOTAL	(19,682,953)	(9,083,656)	(391,759)	(1,507,861)	(2,043,312)	(1,917,767)	(4,726,656)	(8,914)	(2,466)	(563)
Transmission Expenses - Production	9,692,707	PROD_DEMAND	TOTAL	9,692,707	4,555,066	199,533	766,402	1,020,090	931,679	2,211,789	4,424	3,030	692
Transmission Expenses - Transmission	9,547,704	TRANS_TOTAL	TOTAL	9,547,704	4,459,328	194,319	746,894	1,000,154	922,024	2,217,723	4,346	2,373	542
Total Transmission Expenses	19,240,411		TOTAL	19,240,411	9,014,394	393,853	1,513,296	2,020,244	1,853,703	4,429,513	8,769	5,404	1,235
Regional Market Expenses	1,182,188	PROD_DEMAND	TOTAL	1,182,188	555,567	24,336	93,476	124,417	113,634	269,765	540	370	84
Distribution Operation													
580 Supervision & Engineering	675,065	TOTOXEXP	TOTAL	675,065	422,814	43,850	67,058	71,610	26,728	2,270	317	25,766	14,652
581 Load Dispatching	3,746	DIST_CPD	TOTAL	3,746	2,524	107	393	503	216	-	2	-	-
582 Station Expenses	200,568	DIST_CPD	TOTAL	200,568	135,142	5,722	21,040	26,953	11,583	-	129	-	-
583 Overhead Lines	963,651	DIST_OHLINES	TOTAL	963,651	658,264	29,063	100,836	124,914	48,508	-	600	1,208	259
584 Undergroung Lines	108,100	DIST_UGLINES	TOTAL	108,100	74,860	3,439	11,283	13,492	4,630	-	65	273	58
585 Street Lighting	144,034	DIST_SL	TOTAL	144,034	-	-	-	-	-	-	-	-	144,034
586 Meters	853,621	DIST_METERS	TOTAL	853,621	365,254	213,033	120,007	80,774	52,378	22,077	98	-	-
587 Customer Installs	189,223	DIST_PCUST	TOTAL	189,223	120,094	20,687	6,328	722	40	-	10	41,294	49
588 Miscellaneous Distribution	3,878,895	RB_GUP_EPIS_D	TOTAL	3,878,895	2,559,436	173,856	374,701	421,162	139,747	3,433	1,994	183,759	20,806
589 Rents	1,686,536	RB_GUP_EPIS_D	TOTAL	1,686,536	1,112,838	75,592	162,919	183,121	60,762	1,493	867	79,898	9,047
Total Distribution Operations Expenses	8,703,439		TOTAL	8,703,439	5,451,226	565,349	864,564	923,250	344,592	29,273	4,082	332,198	188,905
Distribution Maintenance													
590 Supervision & Engineering	2,253	TOTMXEXP	TOTAL	2,253	1,549	72	234	279	95	0	1	18	5
591 Structures	27,852	DIST_CPD	TOTAL	27,852	18,767	795	2,922	3,743	1,609	-	18	-	-
592 Station Equipment	743,757	DIST_CPD	TOTAL	743,757	501,139	21,217	78,022	99,947	42,954	-	479	-	-
593 Overhead Lines	33,800,787	TOTOHLINES	TOTAL	33,800,787	23,437,333	1,080,574	3,527,030	4,203,376	1,423,783	-	20,237	89,322	19,131
594 Underground Lines	79,484	TOTUGLINES	TOTAL	79,484	55,043	2,529	8,296	9,921	3,405	-	48	200	43
595 Line Transformers	67,093	DIST_TRANSF	TOTAL	67,093	48,664	2,521	6,940	7,248	1,118	-	35	466	100
596 Street Lighting	52,768	DIST_SL	TOTAL	52,768	-	-	-	-	-	-	-	-	52,768
597 Meters	79,342	DIST_METERS	TOTAL	79,342	33,950	19,801	11,154	7,508	4,868	2,052	9	-	-
598 Miscellaneous Distribution	189,656	DIST_OL	TOTAL	189,656	-	-	-	-	-	-	-	189,656	-
Total Distribution Maintenance Expenses	35,042,992		TOTAL	35,042,992	24,096,445	1,127,509	3,634,598	4,332,021	1,477,832	2,052	20,827	279,662	72,047
Total Distribution O&M	43,746,431		TOTAL	43,746,431	29,547,670	1,692,858	4,499,162	5,255,272	1,822,424	31,325	24,909	611,860	260,952
Customer Accounts													
901 Supervision	287,013	TOTOX234	TOTAL	287,013	245,564	30,514	9,917	1,261	123	18	14	(460)	63
902 Meter Read	550,826	CUST_902	TOTAL	550,826	434,545	74,853	34,465	6,099	726	104	35	-	-
903 Customer Records	5,289,588	CUST_903	TOTAL	5,289,588	4,553,010	546,194	167,299	19,533	1,765	252	252	-	1,284
904 Uncollectibles	(42,603)	CUST_TOTAL	TOTAL	(42,603)	(27,030)	(4,656)	(1,426)	(167)	(15)	(2)	(2)	(9,294)	(11)
905 Miscellaneous	25,173	TOTOX234	TOTAL	25,173	21,538	2,676	870	111	11	2	1	(40)	6
Total	6,109,997		TOTAL	6,109,997	5,227,627	649,580	211,125	26,836	2,609	373	300	(9,795)	1,342
Total Customer Services Expenses	5,025,154	CUST_TOTAL	TOTAL	5,025,154	3,188,254	549,196	168,219	19,641	1,775	254	254	1,096,271	1,291
Total Sales Expenses	34,977	CUST_TOTAL	TOTAL	34,977	22,191	3,823	1,171	137	12	2	2	7,630	9
Administrative & General Expense													
A&G - Production Demand	9,250,396	PROD_DEMAND	TOTAL	9,250,396	4,347,203	190,428	731,429	973,540	889,164	2,110,858	4,222	2,892	661
A&G - Production Energy	2,287,520	PROD_ENERGY	TOTAL	2,287,520	812,851	51,288	184,648	252,523	263,331	704,992	1,390	13,549	2,948
A&G - Transmission	864,328	EXP_OM_TRAN	TOTAL	864,328	405,021	17,699	68,002	90,767	83,262	198,883	394	244	56
A&G - Distribution	5,740,193	EXP_OM_DIST	TOTAL	5,740,193	3,877,101	222,128	590,358	689,571	239,130	4,110	3,268	80,285	34,241
A&G - Customer Accounts	928,813	EXP_OM_CUSTACCT	TOTAL	928,813	794,679	98,746	32,094	4,080	397	57	46	(1,489)	204
A&G - Customer Services	(2,747,886)	EXP_OM_CUSTSERV	TOTAL	(2,747,886)	(1,743,421)	(300,315)	(91,987)	(10,740)	(971)	(139)	(139)	(599,470)	(706)
Total A&G Expense Excl Regulatory	16,323,364		TOTAL	16,323,364	8,493,435	279,974	1,514,544	1,999,740	1,474,312	3,018,762	9,181	(503,988)	37,404
A&G - Regulatory Reclassified	268,458	EXP_OM_AG_REG	TOTAL	268,458	112,666	9,182	28,004	32,226	25,579	56,075	172	3,861	693
Total A&G Expenses	16,591,822		TOTAL	16,591,822	8,606,101	289,156	1,542,548	2,031,966	1,499,891	3,074,837	9,353	(500,127)	38,097
Total O&M Expenses	331,764,550		TOTAL	331,764,550	150,923,170	8,843,427	27,301,830	35,561,265	31,323,674	74,943,159	177,587	2,177,044	513,395
O&M Adjustments													
Weather Normalization Adjustment	(3,548,711)	WEATHER_FXNL	TOTAL	(3,548,711)	(3,548,711)	-	-	-	-	-	-	-	-
Customer Annualization Adjustment	(239,052)	REVYEC_EXP_OM	TOTAL	(239,052)	(1,012,039)	45,459	105,759	1,315,602	62,347	(163,174)	1	(561,564)	(31,444)
Removal of AEP Pool Cost	(10,480,841)	PROD_DEMAND	TOTAL	(10,480,841)	(4,925,448)	(215,758)	(828,720)	(1,103,036)	(1,007,436)	(2,391,635)	(4,783)	(3,277)	(749)
System Sales Margins	60,722,845	PROD_ENERGY	TOTAL	60,722,845	21,577,355	1,361,449	4,901,522	6,703,289	6,990,194	18,714,204	36,909	359,665	78,260
Norm/Elim of Comission Mandated Consultant Cost	84,864	REV_SALES	TOTAL	84,864	34,839	2,969	9,034	10,683	8,194	17,776	55	1,098	215
Normalization of Major Storms	(647,763)	TDOMX	TOTAL	(647,763)	(394,878)	(21,310)	(61,637)	(74,700)	(38,256)	(47,754)	(345)	(6,235)	(2,648)
Amortization of Storm Cost Deferral	(2,237,475)	EXP_OM_DIST	TOTAL	(2,237,475)	(1,511,259)	(86,584)	(230,116)	(268,789)	(93,211)	(1,602)	(1,274)	(31,294)	(13,347)

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Rate Case Expense	258,037	EXP_OM_AG_REG	TOTAL	258,037	108,292	8,825	26,917	30,975	24,586	53,899	165	3,711	666
Postage Rate Increase	12,219	CUST_TOTAL	TOTAL	12,219	7,752	1,335	409	48	4	1	1	2,666	3
Eliminate Advertising Expense	(30,610)	EXP_OM_CUSTSERV	TOTAL	(30,610)	(19,421)	(3,345)	(1,025)	(120)	(11)	(2)	(2)	(6,678)	(8)
Annualization of Lease Costs	72,974	TDOMX	TOTAL	72,974	44,485	2,401	6,944	8,415	4,310	5,380	39	702	298
Reliability Adjustment	10,655,900	TOTOHLINES	TOTAL	10,655,900	7,388,759	340,657	1,111,917	1,325,139	448,856	-	6,380	28,159	6,031
Pension & OPEB Expense Adjustment	(206,580)	LABOR_M	TOTAL	(206,580)	(118,595)	(7,354)	(17,499)	(21,187)	(13,822)	(25,085)	(98)	(2,420)	(520)
Amortization of Deferred IGCC Costs	52,505	PROD_DEMAND	TOTAL	52,505	24,675	1,081	4,152	5,526	5,047	11,981	24	16	4
Amortization of Deferred CCS FEED Study Costs	34,425	PROD_DEMAND	TOTAL	34,425	16,178	709	2,722	3,623	3,309	7,855	16	11	2
Amortization of Deferred CARRS Site Costs	103,330	PROD_DEMAND	TOTAL	103,330	48,560	2,127	8,170	10,875	9,932	23,579	47	32	7
Amortization of Deferred Preliminary Big Sandy FGD Costs	1,105,293	PROD_DEMAND	TOTAL	1,105,293	519,430	22,753	87,395	116,324	106,243	252,218	504	346	79
Incentive Compensation Plan Adjustment	(973,508)	LABOR_M	TOTAL	(973,508)	(558,880)	(34,657)	(82,465)	(99,842)	(65,134)	(118,215)	(462)	(11,405)	(2,449)
Annualize T&D Employee-Related Expenses	29,576	LABOR_TD	TOTAL	29,576	19,293	1,084	2,962	3,503	1,413	779	16	368	157
Removal of Big Sandy O&M	(42,717,337)	PROD_DEMAND	TOTAL	(42,717,337)	(20,074,918)	(879,376)	(3,377,659)	(4,495,704)	(4,106,063)	(9,747,716)	(19,495)	(13,356)	(3,051)
PJM Charges & Credits - Pool Term & Removal of Big Sandy	7,584,302	PROD_DEMAND	TOTAL	7,584,302	3,564,226	156,130	599,691	798,195	729,016	1,730,670	3,461	2,371	542
Adjustments to Include Test Year Mitchell Plant O&M	8,839,850	PROD_DEMAND	TOTAL	8,839,850	4,154,268	181,976	698,967	930,333	849,701	2,017,175	4,034	2,764	631
Mitchell Plant Maintenance Normalization	3,223,809	PROD_DEMAND	TOTAL	3,223,809	1,515,022	66,365	254,906	339,284	309,878	735,644	1,471	1,008	230
Eliminate Mitchell O&M FGD	(14,879,350)	PROD_DEMAND	TOTAL	(14,879,350)	(6,992,518)	(306,305)	(1,176,510)	(1,565,949)	(1,430,228)	(3,395,335)	(6,791)	(4,652)	(1,063)
Cost of Removal Adjustment	69,695	PROD_DEMAND	TOTAL	69,695	32,753	1,435	5,511	7,335	6,699	15,904	32	22	5
Mitchell Plant Incentive Compensation Adjustment	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-	-
Mitchell Plant Maintenance	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Mitchell Plant Annualization of Employee-Related Exp	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-	-
Removal of Mitchell Severance Costs	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-	-
Removal of Mitchell Repositioning Study Costs	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-	-
Adj to Incl TY Mitchell Plant O&M and Rate Base - Demand	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Adj to Incl TY Mitchell Plant O&M and Rate Base - Energy	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
PJM - Pool Term & Mitchell Xfer - Prod Demand	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
PJM Charges & Credits - Pool Term & Mitchell Xfer - Energy	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
Amortization of Big Sandy Depreciation & O&M	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Removal of Big Sandy Depreciation & O&M	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Operations and Maintenance Expense Adjustments	16,888,397		TOTAL	16,888,397	(100,779)	642,067	2,051,348	3,979,824	2,805,569	7,696,548	19,907	(237,942)	31,854
Adjusted Operating & Maintenance Expenses	348,652,947		TOTAL	348,652,947	150,822,391	9,485,494	29,353,178	39,541,089	34,129,243	82,639,706	197,493	1,939,103	545,249
Depreciation & Amortization Expense													
Production	46,815,624	RB_GUP_EPIS_P	TOTAL	46,815,624	22,000,899	963,743	3,701,710	4,927,021	4,499,997	10,682,908	21,365	14,637	3,344
Transmission	9,018,286	RB_GUP_EPIS_T	TOTAL	9,018,286	4,212,619	183,590	705,642	944,790	870,811	2,093,960	4,105	2,254	515
Distribution	24,594,927	RB_GUP_EPIS_D	TOTAL	24,594,927	16,228,629	1,102,368	2,375,867	2,670,465	886,097	21,766	12,646	1,165,161	131,927
General & Intangible	3,972,462	RB_GUP_EPIS_G	TOTAL	3,972,462	2,280,545	141,420	336,502	407,410	265,783	482,385	1,884	46,539	9,994
Total Depreciation & Amort Expense	84,401,299		TOTAL	84,401,299	44,722,692	2,391,120	7,119,722	8,949,686	6,522,688	13,281,019	40,001	1,228,591	145,780
Amortization of Intangible Expense	209,475	LABOR_M	TOTAL	209,475	120,257	7,457	17,744	21,483	14,015	25,437	99	2,454	527
ARO Depreciation	237,400	RB_GUP_EPIS_P	TOTAL	237,400	111,566	4,887	18,771	24,985	22,819	54,173	108	74	17
KPCo Depreciation Annualization Expense - Transmission	4,807,980	RB_GUP_EPIS_T	TOTAL	4,807,980	2,245,902	97,878	376,204	503,702	464,261	1,116,367	2,189	1,202	275
KPCo Depreciation Annualization Expense - Distribution	7,225,675	RB_GUP_EPIS_D	TOTAL	7,225,675	4,767,764	323,861	697,999	784,549	260,324	6,395	3,715	342,309	38,759
KPCo Depreciation Annualization Expense - General	737,606	RB_GUP_EPIS_G	TOTAL	737,606	423,451	26,259	62,482	75,648	49,351	89,569	350	8,641	1,856
Annualize Depreciation on Mitchell Plant Investment	3,764,718	PROD_DEMAND	TOTAL	3,764,718	1,769,221	77,500	297,676	396,211	361,871	859,075	1,718	1,177	269
Removal of Big Sandy Depreciation	(17,212,456)	PROD_DEMAND	TOTAL	(17,212,456)	(8,088,956)	(354,334)	(1,360,988)	(1,811,492)	(1,654,490)	(3,927,729)	(7,855)	(5,382)	(1,229)
Remove RTO Amortization	(149,718)	TRANS_TOTAL	TOTAL	(149,718)	(69,927)	(3,047)	(11,712)	(15,683)	(14,458)	(34,776)	(68)	(37)	(9)
Amortization of Big Sandy Depreciation and O&M	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Removal of Big Sandy Depreciation	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Depreciation & Amort Adjustments	(379,320)		TOTAL	(379,320)	1,279,278	180,462	98,176	(20,598)	(496,307)	(1,811,490)	256	350,439	40,464
Adjusted Depreciation Expense	84,021,979		TOTAL	84,021,979	46,001,971	2,571,582	7,217,898	8,929,088	6,026,381	11,469,529	40,257	1,579,030	186,244
Taxes Other Than Income													
Federal Insurance Contribution Excise	3,584,520	LABOR_M	TOTAL	3,584,520	2,057,832	127,609	303,640	367,623	239,827	435,276	1,700	41,994	9,018
Federal Unemployment Tax	48,168	LABOR_M	TOTAL	48,168	27,653	1,715	4,080	4,940	3,223	5,849	23	564	121
Federal Excise Tax	3,707	LABOR_M	TOTAL	3,707	2,128	132	314	380	248	450	2	43	9
Kentucky Unemployment Insurance	73,920	LABOR_M	TOTAL	73,920	42,437	2,632	6,262	7,581	4,946	8,976	35	866	186
Kentucky PSC Maintenance	977,071	REVSALES	TOTAL	977,071	410,055	33,418	101,923	117,289	93,097	204,090	626	14,051	2,522
Kentucky Sales & Use	(101,594)	TDPLANT	TOTAL	(101,594)	(58,835)	(3,513)	(9,033)	(10,869)	(6,236)	(9,932)	(50)	(2,808)	(319)
Kentucky Real & Personal Property	10,260,001	RB_GUP	TOTAL	10,260,001	5,337,477	277,648	856,995	1,087,114	822,872	1,728,620	4,836	129,302	15,138
Kentucky Business Occup Taxes	2,958,572	LABOR_M	TOTAL	2,958,572	1,698,483	105,325	250,617	303,427	197,947	359,266	1,403	34,661	7,443
Lousiana Real & Personal Property	199	RB_GUP	TOTAL	199	104	5	17	21	16	34	0	3	0
West Virginia Real & Personal Property	2,059,339	RB_GUP	TOTAL	2,059,339	1,071,313	55,728	172,012	218,200	165,163	346,960	971	25,953	3,038
West Virginia Unemployment Insurance	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-	-
Ohio Gross Receipts Tax	33,386	REVSALES	TOTAL	33,386	14,011	1,142	3,483	4,008	3,181	6,974	21	480	86
Ohio Franchise Tax	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
West Virginia Franchise Tax	(9,120)	LABOR_M	TOTAL	(9,120)	(5,236)	(325)	(773)	(935)	(610)	(1,107)	(4)	(107)	(23)
Kentucky Municipal License Fees	440	RB_GUP	TOTAL	440	229	12	37	47	35	74	0	6	1
Kentucky License	213	RB_GUP	TOTAL	213	111	6	18	23	17	36	0	3	0

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
West Virginia License Tax	25	LABOR_M	TOTAL	25	14	1	2	3	2	3	0	0	0
Oklahoma License Tax	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Fringe Benefit Loading FICA	(1,236,137)	LABOR_M	TOTAL	(1,236,137)	(709,652)	(44,007)	(104,712)	(126,776)	(82,705)	(150,107)	(586)	(14,482)	(3,110)
Fringe Benefit Loading FUT	(8,884)	LABOR_M	TOTAL	(8,884)	(5,100)	(316)	(753)	(911)	(594)	(1,079)	(4)	(104)	(22)
Fringe Benefit Loading SUT	(22,848)	LABOR_M	TOTAL	(22,848)	(13,117)	(813)	(1,935)	(2,343)	(1,529)	(2,774)	(11)	(268)	(57)
R/E PRS Franchise - CARRS Tax	(46,592)	RB_GUP	TOTAL	(46,592)	(24,238)	(1,261)	(3,892)	(4,937)	(3,737)	(7,850)	(22)	(587)	(69)
Total Taxes Other Than Income	18,574,386		TOTAL	18,574,386	9,845,668	555,138	1,578,301	1,963,884	1,435,163	2,923,759	8,939	229,570	33,963
Remove Big Sandy O&M - Property-related	(900,293)	RB_GUP	TOTAL	(900,293)	(468,352)	(24,363)	(75,199)	(95,392)	(72,205)	(151,683)	(424)	(11,346)	(1,328)
Remove Big Sandy O&M - Payroll-related	(794,970)	LABOR_PROD	TOTAL	(794,970)	(362,488)	(16,543)	(63,018)	(84,164)	(78,255)	(189,158)	(377)	(792)	(175)
Adjs Made to Include Mitchell Plant O&M - Property	1,667,870	RB_GUP	TOTAL	1,667,870	867,662	45,134	139,313	176,722	133,766	281,005	786	21,019	2,461
Adjs Made to Include Mitchell Plant O&M - Payroll	204,840	LABOR_PROD	TOTAL	204,840	93,402	4,263	16,238	21,687	20,164	48,740	97	204	45
Annualization of Property Tax Expense	314,531	RB_GUP	TOTAL	314,531	163,626	8,512	26,272	33,327	25,226	52,993	148	3,964	464
KPSC Maintenance Assessment	92,475	EXP_OTHTAX_PSC	TOTAL	92,475	38,810	3,163	9,646	11,101	8,811	19,316	59	1,330	239
Sales & Use Tax Adjustment	116,430	TDPLANT	TOTAL	116,430	67,427	4,026	10,352	12,456	7,147	11,383	57	3,218	366
State Franchise Tax Adjustment	9,020	LABOR_M	TOTAL	9,020	5,178	321	764	925	603	1,095	4	106	23
KPCO T&D Annualization Employee-Related Exps.	7,011	LABOR_TD	TOTAL	7,011	4,573	257	702	830	335	185	4	87	37
Total Adjustments to Taxes Other Than Income	716,914		TOTAL	716,914	409,839	24,769	65,071	77,491	45,593	73,876	354	17,790	2,131
Adjusted Taxes Other Than Income	19,291,300		TOTAL	19,291,300	10,255,507	579,907	1,643,372	2,041,375	1,480,756	2,997,635	9,294	247,360	36,094
Other Expenses													
Gain/Loss on Disposition of Utility Plant	(3,857)	RB_GUP_EPIS_D	TOTAL	(3,857)	(2,545)	(173)	(373)	(419)	(139)	(3)	(2)	(183)	(21)
Loss on Disposition of Utility Plant	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-	-
Gain/Loss on Disposition of Allowances	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
Accretion	718,740	PROD_DEMAND	TOTAL	718,740	337,770	14,796	56,831	75,642	69,087	164,010	328	225	51
Interest Income - Corp. Borrowing Program	(53,251)	RB_GUP	TOTAL	(53,251)	(27,702)	(1,441)	(4,448)	(5,642)	(4,271)	(8,972)	(25)	(671)	(79)
Interest Expense - Corp. Borrowing Program	28,225	RB_GUP	TOTAL	28,225	14,683	764	2,358	2,991	2,264	4,755	13	356	42
Other Interest Expense	399,669	RB_GUP	TOTAL	399,669	207,917	10,816	33,383	42,348	32,054	67,337	188	5,037	590
Interest on Customer Deposits	32,735	CUST_DEP_FXNL	TOTAL	32,735	23,878	1,437	3,664	1,959	1,636	-	-	160	-
Total Other Expenses	1,122,261		TOTAL	1,122,261	554,001	26,199	91,415	116,879	100,631	227,127	503	4,924	583
ARO Accretion	363,539	PROD_DEMAND	TOTAL	363,539	170,844	7,484	28,745	38,260	34,944	82,956	166	114	26
Adjustment to Interest on Customer Deposits	(2,422)	CUST_DEP_FXNL	TOTAL	(2,422)	(1,767)	(106)	(271)	(145)	(121)	-	-	(12)	-
Total Adjustments to Other Expenses	361,117		TOTAL	361,117	169,078	7,377	28,474	38,115	34,823	82,956	166	102	26
Total Adjusted Other Expenses	1,483,378		TOTAL	1,483,378	723,079	33,576	119,889	154,994	135,454	310,083	669	5,025	609
Total Operating Expense Before Income Tax	453,449,604		TOTAL	453,449,604	207,802,948	12,670,559	38,334,337	50,666,546	41,771,834	97,416,954	247,712	3,770,518	768,196
Gross Operating Income	117,150,056		TOTAL	117,150,056	29,376,450	7,420,899	22,454,864	20,832,570	12,676,791	19,989,032	120,169	3,610,900	668,381
Allowance for Borrowed Funds Used During Construction	1,880,353	RATEBASE	TOTAL	1,880,353	1,001,418	56,000	159,945	202,554	140,319	280,398	934	34,642	4,143
Interest Synchronization Tax	(32,814,262)	RATEBASE	TOTAL	(32,814,262)	(17,475,863)	(977,269)	(2,791,225)	(3,534,791)	(2,448,732)	(4,893,251)	(16,295)	(604,535)	(72,303)
Taxable Income Before Schedule M Adjustments	86,216,147		TOTAL	86,216,147	12,902,005	6,499,630	19,823,584	17,500,333	10,368,379	15,376,179	104,808	3,041,008	600,222
Schedule M Income Adjustments													
Book vs. Tax Depreciation - Normalized	10,392,065	RB_GUP	TOTAL	10,392,065	5,406,180	281,221	868,026	1,101,107	833,464	1,750,871	4,898	130,966	15,333
AFUDC - HR/J	11,364	BULK_TRANS	TOTAL	11,364	5,340	234	899	1,196	1,092	2,593	5	4	1
ABFUDC	(1,880,353)	RB_GUP_CWIP	TOTAL	(1,880,353)	(924,626)	(44,109)	(151,830)	(198,086)	(167,486)	(381,160)	(870)	(10,868)	(1,320)
ABFUDC - HR/J	21,735	BULK_TRANS	TOTAL	21,735	10,214	447	1,719	2,287	2,089	4,960	10	7	2
Interest Capitalization	4,187,996	RB_GUP	TOTAL	4,187,996	2,178,687	113,332	349,814	443,745	335,886	705,600	1,974	52,779	6,179
SEC 481 Pension/OPEB Adjustment	3,045	LABOR_M	TOTAL	3,045	1,748	108	258	312	204	370	1	36	8
Book/Tax Unit of Property	(9,600,340)	RB_GUP	TOTAL	(9,600,340)	(4,994,307)	(259,796)	(801,895)	(1,017,219)	(769,966)	(1,617,480)	(4,525)	(120,988)	(14,165)
Book/Tax Unit of Property - SEC 481	2,703,612	RB_GUP	TOTAL	2,703,612	1,406,478	73,163	225,827	286,465	216,835	455,509	1,274	34,072	3,989
Removal Costs	(8,208,700)	RB_GUP	TOTAL	(8,208,700)	(4,270,345)	(222,137)	(685,654)	(869,765)	(658,354)	(1,383,014)	(3,869)	(103,450)	(12,111)
Tax Amortization of Pollution Control	4,437,000	PROD_DEMAND	TOTAL	4,437,000	2,085,158	91,340	350,833	466,964	426,492	1,012,484	2,025	1,387	317
Provision for Possible Revenue Refunds	(516,436)	REV	TOTAL	(516,436)	(214,610)	(18,182)	(55,021)	(64,716)	(49,294)	(106,308)	(333)	(6,673)	(1,300)
Deferred Fuel	(14,572,129)	FUELREV	TOTAL	(14,572,129)	(5,205,269)	(315,768)	(1,138,809)	(1,515,128)	(1,689,865)	(4,584,850)	(8,593)	(94,861)	(18,986)
Provision for Workers Comp	350,153	LABOR_M	TOTAL	350,153	201,019	12,465	29,661	35,911	23,427	42,520	166	4,102	881
Accrued Book Pension Expense	313,164	LABOR_M	TOTAL	313,164	179,784	11,149	26,528	32,118	20,953	38,028	148	3,669	788
Accrued Book Pension Costs - SFAS 158	(14,366,306)	LABOR_M	TOTAL	(14,366,306)	(8,247,533)	(511,441)	(1,216,951)	(1,473,388)	(961,198)	(1,744,532)	(6,812)	(168,308)	(36,142)
Supplemental Executive Retirement	1,141	LABOR_M	TOTAL	1,141	655	41	97	117	76	139	1	13	3
Accrd Supplemental Exec Retirement SFAS 158	(3,733)	LABOR_M	TOTAL	(3,733)	(2,143)	(133)	(316)	(383)	(250)	(453)	(2)	(44)	(9)
Accrd Supplemental Savings Plan Exp	(100,554)	LABOR_M	TOTAL	(100,554)	(57,727)	(3,580)	(8,518)	(10,313)	(6,728)	(12,210)	(48)	(1,178)	(253)
Accrued PSI Plan Expenses	122,366	LABOR_M	TOTAL	122,366	70,249	4,356	10,365	12,550	8,187	14,859	58	1,434	308
Book Provision for Uncollectible Accounts	(44,200)	CUST_TOTAL	TOTAL	(44,200)	(28,043)	(4,831)	(1,480)	(173)	(16)	(2)	(2)	(9,643)	(11)
Accrued Companywide Incentive Plan - Engage to Gain	(125,184)	LABOR_M	TOTAL	(125,184)	(71,867)	(4,457)	(10,604)	(12,839)	(8,376)	(15,201)	(59)	(1,467)	(315)
Accrued Companywide Incentive Plan	3,270,905	LABOR_M	TOTAL	3,270,905	1,877,789	116,444	277,074	335,459	218,844	397,193	1,551	38,320	8,229

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Accrued Book Vacation Pay	1,827,757	LABOR_M	TOTAL	1,827,757	1,049,295	65,068	154,827	187,452	122,289	221,949	867	21,413	4,598
(ICDP) Incentive Comp Deferral Plan	(66,983)	LABOR_M	TOTAL	(66,983)	(38,454)	(2,385)	(5,674)	(6,870)	(4,482)	(8,134)	(32)	(785)	(169)
Accrued Book Severance Benefits	(1,411)	LABOR_M	TOTAL	(1,411)	(810)	(50)	(120)	(145)	(94)	(171)	(1)	(17)	(4)
Reg Asset on Deferred RTO Costs	213,955	TRANS_TOTAL	TOTAL	213,955	99,929	4,355	16,737	22,412	20,662	49,697	97	53	12
Federal Mitgation Programs		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
State Mitigation Programs	(313,063)	PROD_ENERGY	TOTAL	(313,063)	(111,244)	(7,019)	(25,270)	(34,560)	(36,039)	(96,483)	(190)	(1,854)	(403)
Customer Adv Inc for Tax	24,476	TDPLANT	TOTAL	24,476	14,175	846	2,176	2,618	1,502	2,393	12	676	77
Deferred Book Contract Revenue	(13,407)	REV	TOTAL	(13,407)	(5,571)	(472)	(1,428)	(1,680)	(1,280)	(2,760)	(9)	(173)	(34)
Deferred Storm Damage	4,632,666	EXP_OM_DIST	TOTAL	4,632,666	3,129,044	179,270	476,453	556,524	192,991	3,317	2,638	64,795	27,634
Deferred Demand Side Management Exp	941,289	LABOR_M	TOTAL	941,289	540,383	33,510	79,735	96,537	62,978	114,303	446	11,028	2,368
Advance Rental Income	1,923	REV_OTHER	TOTAL	1,923	1,355	92	214	178	62	(3)	1	22	2
Deferred Rev - Bonus Lease - Short-Term	426,817	REV	TOTAL	426,817	177,368	15,027	45,473	53,486	40,740	87,860	275	5,515	1,074
Deferred Rev - Bonus Lease - Long-Term	1,529,427	REV	TOTAL	1,529,427	635,567	53,846	162,945	191,656	145,983	314,832	986	19,762	3,849
Reg Asset - SFAS 158 Pensions	14,366,306	LABOR_M	TOTAL	14,366,306	8,247,533	511,441	1,216,951	1,473,388	961,198	1,744,532	6,812	168,308	36,142
Reg Asset - SFAS 158 SERP	3,733	LABOR_M	TOTAL	3,733	2,143	133	316	383	250	453	2	44	9
Reg Asset - SFAS 158 OPEB	11,451,882	LABOR_M	TOTAL	11,451,882	6,574,395	407,688	970,074	1,174,489	766,204	1,390,627	5,430	134,164	28,810
Reg Asset - ATR Under Recovery	(3,564,843)	PROD_DEMAND	TOTAL	(3,564,843)	(1,675,290)	(73,386)	(281,872)	(375,175)	(342,659)	(813,465)	(1,627)	(1,115)	(255)
Book Amortization Loss on Reacquired Debt	33,279	RB_GUP	TOTAL	33,279	17,312	901	2,780	3,526	2,669	5,607	16	419	49
Accrued SFAS 106 Post Retirement Exp	(2,674,550)	LABOR_M	TOTAL	(2,674,550)	(1,535,429)	(95,214)	(226,558)	(274,298)	(178,944)	(324,777)	(1,268)	(31,334)	(6,729)
Accrued OPEB Costs SFAS 158	(11,451,882)	LABOR_M	TOTAL	(11,451,882)	(6,574,395)	(407,688)	(970,074)	(1,174,489)	(766,204)	(1,390,627)	(5,430)	(134,164)	(28,810)
Accrd SFAS 112 Post Employment Benefits	911,790	LABOR_M	TOTAL	911,790	523,448	32,460	77,237	93,512	61,005	110,721	432	10,682	2,294
Accrued Book ARO Expense - SFAS 143	1,030,944	RB_GUP	TOTAL	1,030,944	536,320	27,899	86,112	109,235	82,684	173,695	486	12,992	1,521
Reg Asset Medicare Subsidy Flow Thru	214,454	LABOR_M	TOTAL	214,454	123,116	7,635	18,166	21,994	14,348	26,042	102	2,512	540
SFAS 109 - Deferred SIT Liability	3,584,547	REV	TOTAL	3,584,547	1,489,591	126,201	381,898	449,189	342,144	737,877	2,311	46,316	9,020
Reg Asset - SFAS 109 - Deferred SIT Liability	(3,584,547)	REV	TOTAL	(3,584,547)	(1,489,591)	(126,201)	(381,898)	(449,189)	(342,144)	(737,877)	(2,311)	(46,316)	(9,020)
Regulatory Asset Accrued SFAS 112	11,917	LABOR_M	TOTAL	11,917	6,841	424	1,009	1,222	797	1,447	6	140	30
IRS Capitalization Adjustment	(63,083)	REV	TOTAL	(63,083)	(26,215)	(2,221)	(6,721)	(7,905)	(6,021)	(12,986)	(41)	(815)	(159)
Nontaxable Defd Compensation CSV Earn	15,176	LABOR_M	TOTAL	15,176	8,712	540	1,286	1,556	1,015	1,843	7	178	38
Nondeductible Meals and Travel & Entertainment	52,113	LABOR_M	TOTAL	52,113	29,917	1,855	4,414	5,345	3,487	6,328	25	611	131
Capitalized Software Costs Tax	4,276	RB_GUP	TOTAL	4,276	2,224	116	357	453	343	720	2	54	6
Book Leases Capitalized for Tax	(424,281)	RB_GUP	TOTAL	(424,281)	(220,720)	(11,482)	(35,439)	(44,955)	(34,028)	(71,483)	(200)	(5,347)	(626)
Capitalized Software Costs Book	(497,306)	RB_GUP	TOTAL	(497,306)	(258,709)	(13,458)	(41,539)	(52,693)	(39,885)	(83,787)	(234)	(6,267)	(734)
MTM Book Gain Above the Line Tax Deferral	3,087,573	PROD_ENERGY	TOTAL	3,087,573	1,097,143	69,226	249,228	340,842	355,430	951,561	1,877	18,288	3,979
Mark & Spread Deferral - 283 A/L	(32,509)	PROD_ENERGY	TOTAL	(32,509)	(11,552)	(729)	(2,624)	(3,589)	(3,742)	(10,019)	(20)	(193)	(42)
Mark & Spread Deferral - 190 A/L	306,228	PROD_ENERGY	TOTAL	306,228	108,816	6,866	24,719	33,805	35,252	94,377	186	1,814	395
Provision for Trading Credit Risk (Above Line)	(127,666)	PROD_ENERGY	TOTAL	(127,666)	(45,365)	(2,862)	(10,305)	(14,093)	(14,696)	(39,345)	(78)	(756)	(165)
Provision for FAS 157 A/L	14,760	PROD_ENERGY	TOTAL	14,760	5,245	331	1,191	1,629	1,699	4,549	9	87	19
Reg Liability - Unrealized MTM Gain Deferral	(350,135)	PROD_ENERGY	TOTAL	(350,135)	(124,418)	(7,850)	(28,263)	(38,652)	(40,306)	(107,908)	(213)	(2,074)	(451)
Book > Tax Basis - EMA A/C 283	(1,635,359)	PROD_ENERGY	TOTAL	(1,635,359)	(581,111)	(36,666)	(132,005)	(180,530)	(188,257)	(504,002)	(994)	(9,686)	(2,108)
Total Schedule M Adjustments - Per Books	(3,717,126)		TOTAL	(3,717,126)	1,127,830	77,915	(105,469)	(281,167)	(1,007,031)	(3,579,186)	(2,624)	28,289	24,316
Fuel Over/Under Revenues	5,298,776	FUELREV	TOTAL	5,298,776	1,892,761	114,821	414,098	550,937	614,476	1,667,161	3,125	34,494	6,904
Amortization of Storm Cost Deferral	(2,237,475)	EXP_OM_DIST	TOTAL	(2,237,475)	(1,511,259)	(86,584)	(230,116)	(268,789)	(93,211)	(1,602)	(1,274)	(31,294)	(13,347)
Pension and OPEB Expense Adjustment	(226,781)	LABOR_M	TOTAL	(226,781)	(130,192)	(8,073)	(19,210)	(23,258)	(15,173)	(27,539)	(108)	(2,657)	(571)
Amortization of Deferred IGCC Costs	52,505	PROD_DEMAND	TOTAL	52,505	24,675	1,081	4,152	5,526	5,047	11,981	24	16	4
Amortization of Deferred CCS FEED Study Costs	34,425	PROD_DEMAND	TOTAL	34,425	16,178	709	2,722	3,623	3,309	7,855	16	11	2
Amortization of Deferred CARRS Site Costs	103,330	PROD_DEMAND	TOTAL	103,330	48,560	2,127	8,170	10,875	9,932	23,579	47	32	7
Amortization of Defd Preliminary Big Sandy FGD Costs	1,105,293	PROD_DEMAND	TOTAL	1,105,293	519,430	22,753	87,395	116,324	106,243	252,218	504	346	79
Incentive Compensation Plan Adjustment	66,983	LABOR_M	TOTAL	66,983	38,454	2,385	5,674	6,870	4,482	8,134	32	785	169
KPCo Depreciation Annualization Exp - T&D Plant	12,771,261	TDPLANT	TOTAL	12,771,261	7,396,085	441,562	1,135,528	1,366,278	783,917	1,248,571	6,251	352,951	40,118
Amortization of Intangible Expenses	209,475	LABOR_M	TOTAL	209,475	120,257	7,457	17,744	21,483	14,015	25,437	99	2,454	527
Mitchell Depreciation Annualization - Production	3,764,718	PROD_DEMAND	TOTAL	3,764,718	1,769,221	77,500	297,676	396,211	361,871	859,075	1,718	1,177	269
Removal of Big Sandy Depreciation	(17,212,456)	PROD_DEMAND	TOTAL	(17,212,456)	(8,088,956)	(354,334)	(1,360,988)	(1,811,492)	(1,654,490)	(3,927,729)	(7,855)	(5,382)	(1,229)
ARO Depreciation Adjustment	237,400	PROD_DEMAND	TOTAL	237,400	111,566	4,887	18,771	24,985	22,819	54,173	108	74	17
Remval of RTO Amortization	(149,718)	TRANS_TOTAL	TOTAL	(149,718)	(69,927)	(3,047)	(11,712)	(15,683)	(14,458)	(34,776)	(68)	(37)	(9)
ARO Accretion	363,539	PROD_DEMAND	TOTAL	363,539	170,844	7,484	28,745	38,260	34,944	82,956	166	114	26
Annualize Removal Cost - Schedule M Adjustment	326,280	RB_GUP	TOTAL	326,280	169,738	8,830	27,253	34,571	26,168	54,972	154	4,112	481
Annualize Section 199 Manuf. Deduct. @ Separate Return	(117,148)	RB_GUP_EPIS_P	TOTAL	(117,148)	(55,053)	(2,412)	(9,263)	(12,329)	(11,260)	(26,732)	(53)	(37)	(8)
Mitchell Plant Depreciation-Related Shedule M's	(3,892,704)	PROD_DEMAND	TOTAL	(3,892,704)	(1,829,368)	(80,135)	(307,796)	(409,680)	(374,173)	(888,280)	(1,777)	(1,217)	(278)
Mitchell Depreciation Annualization - Production	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Annualize Section 199 Manuf. Deduct. @ Separate Return	-	RB_GUP_EPIS_P	TOTAL	-	-	-	-	-	-	-	-	-	-
Mitchell Plant Depreciation-Related Shedule M's	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Adjustments to Per Books Schedule M	497,703		TOTAL	497,703	593,014	157,010	108,844	34,711	(175,543)	(610,546)	1,109	355,941	33,161
Adjusted Schedule M	(3,219,423)		TOTAL	(3,219,423)	1,720,844	234,925	3,376	(246,455)	(1,182,574)	(4,189,731)	(1,514)	384,230	57,477
Amortization of Big Sandy Depreciation & O&M - O&M	-	PROD_DEMAND											
Kentucky Taxable Income Before Adjustments	82,996,724		TOTAL	82,996,724	14,622,850	6,734,556	19,826,960	17,253,878	9,185,804	11,186,447	103,294	3,425,237	657,698
JCWA Depreciation Adjustment	(6,013,710)	RB_GUP	TOTAL	(6,013,710)	(3,128,464)	(162,738)	(502,312)	(637,192)	(482,311)	(1,013,199)	(2,835)	(75,788)	(8,873)
Federal Domestic Production Activity	117,148	RB_GUP_EPIS_P	TOTAL	117,148	55,053	2,412	9,263	12,329	11,260	26,732	53	37	8

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Kentucky Taxable Income	77,100,162		TOTAL	77,100,162	11,549,440	6,574,229	19,333,911	16,629,015	8,714,753	10,199,981	100,512	3,349,486	648,834
Tax Factor (Tax Rate x Apportionment)	4.4341800%												
Kentucky Tax	3,418,760		TOTAL	3,418,760	512,123	291,513	857,300	737,360	386,428	452,286	4,457	148,522	28,770
West Virginia Taxable Income Before Adjustments	82,996,724		TOTAL	82,996,724	14,622,850	6,734,556	19,826,960	17,253,878	9,185,804	11,186,447	103,294	3,425,237	657,698
Federal Domestic Production Activity	117,148	RB_GUP_EPIS_P	TOTAL	117,148	55,053	2,412	9,263	12,329	11,260	26,732	53	37	8
West Virginia Taxable Income	83,113,872		TOTAL	83,113,872	14,677,903	6,736,967	19,836,223	17,266,207	9,197,065	11,213,179	103,347	3,425,274	657,707
Apportionment Factor	17.7890000%												
Apportioned West Virginia Taxable Income	14,785,127		TOTAL	14,785,127	2,611,052	1,198,439	3,528,666	3,071,486	1,636,066	1,994,712	18,384	609,322	116,999
Post Apportionment Schedule M Adjustments	6,978,384	RB_GUP	TOTAL	6,978,384	3,630,308	188,843	582,889	739,405	559,680	1,175,728	3,289	87,945	10,296
Post Apportionment Taxable Income	21,763,511		TOTAL	21,763,511	6,241,360	1,387,282	4,111,554	3,810,891	2,195,746	3,170,441	21,674	697,267	127,296
Tax Rate	6.5000000%												
West Virginia Tax	1,414,628		TOTAL	1,414,628	405,688	90,173	267,251	247,708	142,723	206,079	1,409	45,322	8,274
Illinois Taxable Income Before Depreciation Adjustment	82,996,724		TOTAL	82,996,724	14,622,850	6,734,556	19,826,960	17,253,878	9,185,804	11,186,447	103,294	3,425,237	657,698
JCWA Depreciation Adjustment	(2,658,840)	RB_GUP	TOTAL	(2,658,840)	(1,383,187)	(71,951)	(222,087)	(281,721)	(213,244)	(447,965)	(1,253)	(33,508)	(3,923)
Federal Domestic Production Activity	117,148	RB_GUP_EPIS_P	TOTAL	117,148	55,053	2,412	9,263	12,329	11,260	26,732	53	37	8
Illinois Taxable Income	80,455,032		TOTAL	80,455,032	13,294,716	6,665,016	19,614,136	16,984,485	8,983,821	10,765,214	102,094	3,391,766	653,784
Apportionment Factor	1.4511000%												
Apportioned Illinois State Taxable Income	1,167,483		TOTAL	1,167,483	192,920	96,716	284,621	246,462	130,364	156,214	1,481	49,218	9,487
Post Apportionment Schedule M Adjustments	(79,783)	RB_GUP	TOTAL	(79,783)	(41,505)	(2,159)	(6,664)	(8,454)	(6,399)	(13,442)	(38)	(1,005)	(118)
Post Apportionment Taxable Income	1,087,700		TOTAL	1,087,700	151,415	94,557	277,957	238,008	123,965	142,772	1,444	48,212	9,369
Tax Rate	9.5000000%												
Illinois Tax	103,331		TOTAL	103,331	14,384	8,983	26,406	22,611	11,777	13,563	137	4,580	890
Michigan Taxable Income Before Depreciation Adjustment	82,996,724		TOTAL	82,996,724	14,622,850	6,734,556	19,826,960	17,253,878	9,185,804	11,186,447	103,294	3,425,237	657,698
JCWA Depreciation Adjustment	(4,544,916)	RB_GUP	TOTAL	(4,544,916)	(2,364,365)	(122,991)	(379,627)	(481,563)	(364,511)	(765,734)	(2,142)	(57,277)	(6,706)
Federal Domestic Production Activity	117,148	RB_GUP_EPIS_P	TOTAL	117,148	55,053	2,412	9,263	12,329	11,260	26,732	53	37	8
Michigan Taxable Income	78,568,956		TOTAL	78,568,956	12,313,538	6,613,976	19,456,596	16,784,643	8,832,554	10,447,445	101,205	3,367,997	651,001
Tax Factor (Tax Rate x Apportionment)	0.0064140%												
Michigan Tax	5,039		TOTAL	5,039	790	424	1,248	1,077	567	670	6	216	42
Total Current State Income Tax	4,941,759		TOTAL	4,941,759	932,986	391,094	1,152,205	1,008,756	541,495	672,598	6,009	198,641	37,977
Deferred State Income Tax	(453,595)		TOTAL	(453,595)	(235,970)	(12,275)	(37,888)	(48,061)	(36,379)	(76,422)	(214)	(5,716)	(669)
Mitchell Plant DSIT Amortization Adjustment	(197,446)	RB_GUP_EPIS_P	TOTAL	(197,446)	(92,789)	(4,065)	(15,612)	(20,780)	(18,979)	(45,055)	(90)	(62)	(14)
Total Adjusted Deferred State Income Tax	(651,041)		TOTAL	(651,041)	(328,759)	(16,339)	(53,500)	(68,841)	(55,358)	(121,478)	(304)	(5,778)	(683)
Total State Income Tax	4,290,718		TOTAL	4,290,718	604,226	374,754	1,098,705	939,915	486,137	551,120	5,705	192,863	37,293
Federal Taxable Income	78,054,965		TOTAL	78,054,965	13,689,864	6,343,462	18,674,755	16,245,122	8,644,310	10,513,850	97,284	3,226,597	619,722
Tax Factor (Tax Rate x Apportionment)	35.00%												
Gross Current FIT	27,319,238		TOTAL	27,319,238	4,791,452	2,220,212	6,536,164	5,685,793	3,025,508	3,679,847	34,049	1,129,309	216,903
Feedback Prior ITC Normalization Tax	(128,109)	RB_GUP	TOTAL	(128,109)	(66,645)	(3,467)	(10,701)	(13,574)	(10,275)	(21,584)	(60)	(1,614)	(189)
Defd Investment Tax Credit Adjustment	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-	-
Total Current FIT & ITC	27,191,129		TOTAL	27,191,129	4,724,807	2,216,745	6,525,463	5,672,219	3,015,234	3,658,263	33,989	1,127,694	216,714
Deferred FIT													
DFIT for Book vs Tax Depreciation Normalized	(1,043,995)	RB_GUP	TOTAL	(1,043,995)	(543,109)	(28,252)	(87,203)	(110,618)	(83,730)	(175,894)	(492)	(13,157)	(1,540)
DFIT ABFUDC	428,401	RB_GUP_CWIP	TOTAL	428,401	210,658	10,049	34,591	45,130	38,158	86,840	198	2,476	301
Interest Capitalization	(1,137,462)	RB_GUP	TOTAL	(1,137,462)	(591,733)	(30,781)	(95,010)	(120,522)	(91,227)	(191,641)	(536)	(14,335)	(1,678)
Capitalized Overheads - Taxes	(8,246)	RB_GUP	TOTAL	(8,246)	(4,290)	(223)	(689)	(874)	(661)	(1,389)	(4)	(104)	(12)
Capitalized Overheads - Pension/OPEB	(1,066)	LABOR_M	TOTAL	(1,066)	(612)	(38)	(90)	(109)	(71)	(129)	(1)	(12)	(3)
Capitalized Overheads - Savings Plan	(1,045)	LABOR_M	TOTAL	(1,045)	(600)	(37)	(89)	(107)	(70)	(127)	(0)	(12)	(3)
Percent Repair Allowance	1,882,577	RB_GUP	TOTAL	1,882,577	979,358	50,945	157,247	199,471	150,986	317,179	887	23,725	2,778
Tax Amortization of Pollution Control Equip.	(1,552,950)	PROD_DEMAND	TOTAL	(1,552,950)	(729,805)	(31,969)	(122,792)	(163,437)	(149,272)	(354,369)	(709)	(486)	(111)
Provision for Possible Revenue Refunds	180,752	REV	TOTAL	180,752	75,113	6,364	19,257	22,651	17,253	37,208	117	2,336	455
Deferred Fuel Costs	5,100,245	FUELREV	TOTAL	5,100,245	1,821,844	110,519	398,583	530,295	591,453	1,604,697	3,008	33,201	6,645
Provision for Workers Comp	(122,553)	LABOR_M	TOTAL	(122,553)	(70,356)	(4,363)	(10,381)	(12,569)	(8,200)	(14,882)	(58)	(1,436)	(308)
Accrued Book Pension Expense	(109,607)	LABOR_M	TOTAL	(109,607)	(62,924)	(3,902)	(9,285)	(11,241)	(7,333)	(13,310)	(52)	(1,284)	(276)
Accrued Book Pension Costs - SFAS 158	5,028,207	LABOR_M	TOTAL	5,028,207	2,886,637	179,004	425,933	515,686	336,419	610,586	2,384	58,908	12,650
Supplemental Executive Retirement	(399)	LABOR_M	TOTAL	(399)	(229)	(14)	(34)	(41)	(27)	(48)	(0)	(5)	(1)
Accrd Suppl Executive Retirement - SFAS 158	1,307	LABOR_M	TOTAL	1,307	750	47	111	134	87	159	1	15	3
Accrd Book Supplemental Savings Plan	35,195	LABOR_M	TOTAL	35,195	20,205	1,253	2,981	3,610	2,355	4,274	17	412	89
Accrued PSI Plan Expenses	(42,827)	LABOR_M	TOTAL	(42,827)	(24,586)	(1,525)	(3,628)	(4,392)	(2,865)	(5,201)	(20)	(502)	(108)
Book Provision - Uncollectible Accounts	15,470	CUST_TOTAL	TOTAL	15,470	9,815	1,691	518	60	5	1	1	3,375	4
Accrd Companywide Incentive Plan - Engage to Gain	43,813	LABOR_M	TOTAL	43,813	25,153	1,560	3,711	4,493	2,931	5,320	21	513	110
Accrd Companywide Incentive Plan	(1,144,816)	LABOR_M	TOTAL	(1,144,816)	(657,226)	(40,756)	(96,976)	(117,411)	(76,596)	(139,018)	(543)	(13,412)	(2,880)

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Accrd Book Vacation Pay	(639,715)	LABOR_M	TOTAL	(639,715)	(367,253)	(22,774)	(54,189)	(65,608)	(42,801)	(77,682)	(303)	(7,495)	(1,609)
(IDCP) Incentive Comp Deferral Plan	23,444	LABOR_M	TOTAL	23,444	13,459	835	1,986	2,404	1,569	2,847	11	275	59
Accrd Book Severance Benefits	494	LABOR_M	TOTAL	494	284	18	42	51	33	60	0	6	1
Reg Asset on Deferred RTO Costs	(74,884)	TRANS_TOTAL	TOTAL	(74,884)	(34,975)	(1,524)	(5,858)	(7,844)	(7,232)	(17,394)	(34)	(19)	(4)
Federal Mitigation Programs	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-	-
State Mitigation Programs	109,572	PROD_ENERGY	TOTAL	109,572	38,935	2,457	8,845	12,096	12,614	33,769	67	649	141
Customer Adv Inc for Tax	(8,566)	TDPLANT	TOTAL	(8,566)	(4,961)	(296)	(762)	(916)	(526)	(837)	(4)	(237)	(27)
Deferred Book Contract Revenue	4,693	REV	TOTAL	4,693	1,950	165	500	588	448	966	3	61	12
Deferred Storm Damage	(1,621,433)	EXP_OM_DIST	TOTAL	(1,621,433)	(1,095,165)	(62,745)	(166,759)	(194,783)	(67,547)	(1,161)	(923)	(22,678)	(9,672)
Deferred Demand Side Management Exp	(329,450)	LABOR_M	TOTAL	(329,450)	(189,134)	(11,728)	(27,907)	(33,788)	(22,042)	(40,006)	(156)	(3,860)	(829)
Advance Rental Income	(673)	REV_OTHER	TOTAL	(673)	(474)	(32)	(75)	(62)	(22)	1	(0)	(8)	(1)
Deferred Revenue - Bonus Lease Short-Term	(149,385)	REV_OTHER	TOTAL	(149,385)	(105,248)	(7,172)	(16,651)	(13,815)	(4,788)	268	(53)	(1,733)	(192)
Deferred Revenue - Bonus Lease Long-Term	(535,299)	REV_OTHER	TOTAL	(535,299)	(377,142)	(25,700)	(59,665)	(49,505)	(17,159)	959	(190)	(6,210)	(687)
Reg Asset SFAS 158 Pensions	(5,028,207)	LABOR_M	TOTAL	(5,028,207)	(2,886,637)	(179,004)	(425,933)	(515,686)	(336,419)	(610,586)	(2,384)	(58,908)	(12,650)
Reg Asset SFAS 158 SERP	(1,307)	LABOR_M	TOTAL	(1,307)	(750)	(47)	(111)	(134)	(87)	(159)	(1)	(15)	(3)
Reg Asset SFAS 158 OPEB	(4,008,159)	LABOR_M	TOTAL	(4,008,159)	(2,301,039)	(142,691)	(339,526)	(411,071)	(268,171)	(486,720)	(1,901)	(46,957)	(10,084)
Reg Asset - ATR Under Recovery	1,247,694	PROD_DEMAND	TOTAL	1,247,694	586,351	25,685	98,655	131,311	119,930	284,713	569	390	89
Book Amortization Loss on Reacquired Debt	(11,647)	RB_GUP	TOTAL	(11,647)	(6,059)	(315)	(973)	(1,234)	(934)	(1,962)	(5)	(147)	(17)
Accrued SFAS 106 Post Retirement Expense	936,093	LABOR_M	TOTAL	936,093	537,400	33,325	79,295	96,004	62,631	113,672	444	10,967	2,355
Accrued OPEB Costs SFAS 158	4,008,159	LABOR_M	TOTAL	4,008,159	2,301,039	142,691	339,526	411,071	268,171	486,720	1,901	46,957	10,084
Accrued SFAS 112 Post Employment Benefits	(319,127)	LABOR_M	TOTAL	(319,127)	(183,207)	(11,361)	(27,033)	(32,729)	(21,352)	(38,752)	(151)	(3,739)	(803)
Accrued Book ARO Expense SFAS 143	(360,831)	RB_GUP	TOTAL	(360,831)	(187,712)	(9,765)	(30,139)	(38,232)	(28,939)	(60,793)	(170)	(4,547)	(532)
Medicare Subsidy (PPACA) Reg Asset	(75,059)	LABOR_M	TOTAL	(75,059)	(43,091)	(2,672)	(6,358)	(7,698)	(5,022)	(9,115)	(36)	(879)	(189)
Deferred State Income Taxes	158,758	RB_GUP	TOTAL	158,758	82,589	4,296	13,261	16,821	12,733	26,748	75	2,001	234
Reg Asset - Accrued SFAS 112	(4,171)	LABOR_M	TOTAL	(4,171)	(2,395)	(148)	(353)	(428)	(279)	(506)	(2)	(49)	(10)
IRS Capitalization Adjustment	22,079	REV	TOTAL	22,079	9,175	777	2,352	2,767	2,107	4,545	14	285	56
Capitalized Software Costs Tax	(1,496)	RB_GUP	TOTAL	(1,496)	(778)	(40)	(125)	(159)	(120)	(252)	(1)	(19)	(2)
Book Leases Capitalized for Tax	148,498	RB_GUP	TOTAL	148,498	77,252	4,019	12,404	15,734	11,910	25,019	70	1,871	219
Capitalized Software Costs Book	174,057	RB_GUP	TOTAL	174,057	90,548	4,710	14,539	18,442	13,960	29,325	82	2,194	257
MTM Book Gain Above the Line Tax Deferral	(1,080,651)	PROD_ENERGY	TOTAL	(1,080,651)	(384,000)	(24,229)	(87,230)	(119,295)	(124,401)	(333,046)	(657)	(6,401)	(1,393)
Mark & Spread Deferral - 283 A/L	11,378	PROD_ENERGY	TOTAL	11,378	4,043	255	918	1,256	1,310	3,507	7	67	15
Mark & Spread Deferral - 190 A/L	(107,180)	PROD_ENERGY	TOTAL	(107,180)	(38,086)	(2,403)	(8,652)	(11,832)	(12,338)	(33,032)	(65)	(635)	(138)
Prov for Trading Credit Risk - Above the Line	44,684	PROD_ENERGY	TOTAL	44,684	15,878	1,002	3,607	4,933	5,144	13,771	27	265	58
Provision for FAS 157 A/L	(5,166)	PROD_ENERGY	TOTAL	(5,166)	(1,836)	(116)	(417)	(570)	(595)	(1,592)	(3)	(31)	(7)
Reg Liability - Unrealized MTM Gain Deferral	122,547	PROD_ENERGY	TOTAL	122,547	43,546	2,748	9,892	13,528	14,107	37,768	74	726	158
Book > Tax Basis - EMA A/C 283	572,375	PROD_ENERGY	TOTAL	572,375	203,389	12,833	46,202	63,185	65,890	176,401	348	3,390	738
Total Per Books DFIT	773,120		TOTAL	773,120	(860,041)	(49,376)	(9,934)	65,011	351,378	1,297,717	869	(14,244)	(8,260)
DFIT Adjustments													
Fuel Over/Under Revenues	(1,854,572)	FUELREV	TOTAL	(1,854,572)	(662,466)	(40,187)	(144,934)	(192,828)	(215,066)	(583,507)	(1,094)	(12,073)	(2,416)
Amortization of Storm Cost Deferral	783,116	EXP_OM_DIST	TOTAL	783,116	528,940	30,304	80,541	94,076	32,624	561	446	10,953	4,671
Pension and OPEB Expense Adjustment	79,373	LABOR_M	TOTAL	79,373	45,567	2,826	6,724	8,140	5,311	9,638	38	930	200
Amortization of Deferred IGCC Costs	(18,377)	PROD_DEMAND	TOTAL	(18,377)	(8,636)	(378)	(1,453)	(1,934)	(1,766)	(4,193)	(8)	(6)	(1)
Amortization of Deferred CCS FEED Study Costs	(12,049)	PROD_DEMAND	TOTAL	(12,049)	(5,662)	(248)	(953)	(1,268)	(1,158)	(2,749)	(5)	(4)	(1)
Amortization of Deferred CARRS Site Costs	(36,166)	PROD_DEMAND	TOTAL	(36,166)	(16,996)	(745)	(2,860)	(3,806)	(3,476)	(8,253)	(17)	(11)	(3)
Amortization of Defd Preliminary Big Sandy FGD Costs	(386,853)	PROD_DEMAND	TOTAL	(386,853)	(181,801)	(7,964)	(30,588)	(40,714)	(37,185)	(88,276)	(177)	(121)	(28)
Incentive Compensation Plan Adjustment	(23,444)	LABOR_M	TOTAL	(23,444)	(13,459)	(835)	(1,986)	(2,404)	(1,569)	(2,847)	(11)	(275)	(59)
KPCo Depreciation Annualization Exp - T&D Plant	(3,698,393)	TDPLANT	TOTAL	(3,698,393)	(2,141,811)	(127,871)	(328,834)	(395,657)	(227,012)	(361,570)	(1,810)	(102,210)	(11,618)
Amortization of Intangible Expenses	(73,316)	LABOR_M	TOTAL	(73,316)	(42,090)	(2,610)	(6,211)	(7,519)	(4,905)	(8,903)	(35)	(859)	(184)
Mitchell Depreciation Annualization - Production	(1,317,651)	PROD_DEMAND	TOTAL	(1,317,651)	(619,227)	(27,125)	(104,187)	(138,674)	(126,655)	(300,676)	(601)	(412)	(94)
Removal of Big Sandy Depreciation	4,511,643	PROD_DEMAND	TOTAL	4,511,643	2,120,237	92,876	356,735	474,819	433,667	1,029,517	2,059	1,411	322
ARO Depreciation Adjustment	(83,090)	PROD_DEMAND	TOTAL	(83,090)	(39,048)	(1,710)	(6,570)	(8,745)	(7,987)	(18,960)	(38)	(26)	(6)
Remval of RTO Amortization	52,401	TRANS_TOTAL	TOTAL	52,401	24,474	1,066	4,099	5,489	5,060	12,172	24	13	3
ARO Accretion	(127,239)	PROD_DEMAND	TOTAL	(127,239)	(59,796)	(2,619)	(10,061)	(13,391)	(12,230)	(29,035)	(58)	(40)	(9)
Mitchell Plant Depreciation-Related Shedule M's	1,362,446	PROD_DEMAND	TOTAL	1,362,446	640,278	28,047	107,729	143,388	130,961	310,898	622	426	97
KPCO AFUDC Offset	90,039	AFUDC_OFF	TOTAL	90,039	43,691	2,034	7,226	9,484	8,206	18,927	41	382	47
Mitchell Plant DSIT Amortization Adjustment	69,106	RB_GUP_EPIS_P	TOTAL	69,106	32,476	1,423	5,464	7,273	6,643	15,769	32	22	5
Total Adjustments to DFIT	(683,026)		TOTAL	(683,026)	(355,329)	(53,715)	(70,118)	(64,270)	(16,540)	(11,488)	(593)	(101,900)	(9,074)
Total Deferred FIT	90,094		TOTAL	90,094	(1,215,370)	(103,091)	(80,052)	742	334,838	1,286,229	277	(116,144)	(17,334)
Total Federal Income Tax	27,281,223		TOTAL	27,281,223	3,509,438	2,113,654	6,445,411	5,672,960	3,350,072	4,944,492	34,266	1,011,550	199,380
Total Income Tax	31,571,941		TOTAL	31,571,941	4,113,664	2,488,408	7,544,117	6,612,875	3,836,208	5,495,612	39,971	1,204,413	236,673
Total Expenses	485,021,545		TOTAL	485,021,545	211,916,612	15,158,967	45,878,454	57,279,421	45,608,042	102,912,566	287,683	4,974,931	1,004,869
Net Operating Income	85,578,115		TOTAL	85,578,115	25,262,786	4,932,491	14,910,747	14,219,695	8,840,583	14,493,420	80,198	2,406,487	431,708
AFUDC Offset													
Production	3,072,237	PROD_DEMAND	TOTAL	3,072,237	1,443,791	63,245	242,922	323,332	295,309	701,057	1,402	961	219

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	SGS 3	Total MGS	Total LGS	Total QP	Total CIP-TOD	MW 17	OL 18	SL 19
Transmission	1,946,078	RB_GUP_EPIS_T	TOTAL	1,946,078	909,051	39,617	152,272	203,879	187,914	451,861	886	486	111
Distribution	454,455	RB_GUP_EPIS_D	TOTAL	454,455	299,866	20,369	43,900	49,344	16,373	402	234	21,529	2,438
General	32,717	LABOR_M	TOTAL	32,717	18,782	1,165	2,771	3,355	2,189	3,973	16	383	82
Total Per Books AFUDC Offset	5,505,487		TOTAL	5,505,487	2,671,491	124,396	441,866	579,909	501,785	1,157,293	2,537	23,360	2,851
AFUDC Offset Adjustment	250,424	PROD_DEMAND	TOTAL	250,424	117,686	5,155	19,801	26,355	24,071	57,145	114	78	18
Mitchell AFUDC Offset Adjustment	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-	-
Total AFUDC Offset Adjustments	250,424	PROD_DEMAND	TOTAL	250,424	117,686	5,155	19,801	26,355	24,071	57,145	114	78	18
Total Adjusted AFUDC Offsets	5,755,911		TOTAL	5,755,911	2,789,177	129,551	461,667	606,265	525,856	1,214,437	2,651	23,438	2,868
AdjustedNet Operating Income	91,334,026		TOTAL	91,334,026	28,051,963	5,062,042	15,372,414	14,825,960	9,366,439	15,707,857	82,849	2,429,925	434,576
Current Rate of Return				7.89%	4.55%	14.68%	15.60%	11.88%	10.84%	9.10%	14.41%	11.39%	17.03%
O&M Labor													
Production Demand	8,609,401	PROD_DEMAND	TOTAL	8,609,401	4,045,969	177,232	680,745	906,080	827,550	1,964,589	3,929	2,692	615
Production Energy	1,195,224	PROD_ENERGY	TOTAL	1,195,224	424,713	26,798	96,478	131,943	137,590	368,357	726	7,079	1,540
Transmission	1,073,438	EXP_OM_TRAN	TOTAL	1,073,438	503,009	21,981	84,454	112,726	103,406	247,000	489	303	69
Distribution	8,536,264	EXP_OM_DIST	TOTAL	8,536,264	5,765,652	330,328	877,924	1,025,464	355,611	6,112	4,861	119,393	50,920
Customer Accounts	1,322,911	EXP_OM_CUSTACCT	TOTAL	1,322,911	1,131,864	140,644	45,712	5,810	565	81	65	(2,121)	290
Customer Service	559,966	EXP_OM_CUSTSERV	TOTAL	559,966	355,275	61,198	18,745	2,189	198	28	28	122,160	144
Total	21,297,204		TOTAL	21,297,204	12,226,483	758,182	1,804,058	2,184,212	1,424,919	2,586,167	10,099	249,507	53,579
Production Demand	8,609,401	PROD_DEMAND	TOTAL	8,609,401	4,045,969	177,232	680,745	906,080	827,550	1,964,589	3,929	2,692	615
Production Energy	1,195,224	PROD_ENERGY	TOTAL	1,195,224	424,713	26,798	96,478	131,943	137,590	368,357	726	7,079	1,540
Total Production	9,804,625		TOTAL	9,804,625	4,470,682	204,030	777,223	1,038,023	965,140	2,332,945	4,656	9,771	2,155
Calculation of Proposed Revenues													
Proposed Operating Income	88,470,733	RATEBASE	TOTAL	88,470,733	26,527,064	4,976,767	15,128,858	14,517,523	9,152,768	15,280,884	81,427	2,377,175	428,267
					26,527,064	4,976,767	15,128,858	14,517,523	9,152,768	15,280,884	81,427	2,377,175	428,267
Proposed Rate of Return				7.64%	4.30%	14.43%	15.36%	11.64%	10.59%	8.85%	14.16%	11.14%	16.78%
Income Increase	(2,863,293)		TOTAL	(2,863,293)	(1,524,899)	(85,275)	(243,556)	(308,437)	(213,671)	(426,973)	(1,422)	(52,750)	(6,309)
Gross Revenue Conversion Factor	1.6402												
Revenue Increase	(4,696,313)		TOTAL	(4,696,313)	(2,501,107)	(139,866)	(399,475)	(505,892)	(350,459)	(700,313)	(2,333)	(86,520)	(10,349)
Percent Revenue Increase				-0.84%	-1.09%	-0.71%	-0.67%	-0.72%	-0.65%	-0.60%	-0.64%	-1.19%	-0.73%
Proposed Sales Revenue	555,896,762		TOTAL	555,896,762	227,639,467	19,471,978	59,278,116	70,063,746	53,776,408	116,722,931	361,952	7,169,804	1,412,361
Adjust Transmission OATT	(126,908)		TOTAL	(126,908)	7,903,930	(643,599)	(2,871,337)	(1,829,055)	(1,348,509)	(1,313,469)	(14,795)	(7,305)	(2,769)
			PRODUCTION	186,439,680	76,396,686	4,569,088	18,095,605	22,797,382	19,692,588	44,700,977	103,875	64,535	18,945
			BULKTRAN	-	-	-	-	-	-	-	-	-	-
			SUBTRAN	-	-	-	-	-	-	-	-	-	-
			DISTPRI	82,654,958	47,203,012	3,227,757	12,362,190	14,076,296	5,711,912	(0)	73,792	0	-
			DISTSEC	34,625,386	21,937,720	2,049,932	5,444,132	4,548,249	128,427	(0)	24,925	381,203	110,798
			ENERGY	226,505,780	77,357,442	5,219,426	18,951,622	26,244,196	26,587,649	70,591,022	142,805	1,118,464	293,154
	555,769,854		CUSTOMER	25,544,050	12,648,538	3,762,175	1,553,231	568,569	307,323	117,463	1,760	5,598,297	986,695
Total Proposed Sales Revenue	555,769,854		TOTAL	555,769,854	235,543,397	18,828,379	56,406,779	68,234,690	52,427,899	115,409,462	347,156	7,162,499	1,409,592

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	QP-SEC 11	QP-PRI 12	QP-SUB 13	QP-TRA 14	CIP-TOD-SUB 15	CIP-TOD-TRA 16	MW 17	OL 18	SL 19
AFUDC_OFF PRODUCTION	0.56818639	0.26701793	0.01169664	0.04405495	0.00078894	0.00008259	0.04770727	0.00928814	0.00274803	0.00005425	0.00166713	0.02309704	0.02447444	0.00537643	0.11235170	0.01730337	0.00025931	0.00017765	0.00004058
AFUDC_OFF BULKTRAN	0.27509146	0.12927862	0.00566301	0.02132952	0.00038197	0.00003999	0.02309781	0.00449692	0.00133048	0.00002627	0.00080715	0.01118260	0.01184947	0.00260304	0.05439587	0.00837755	0.00012554	0.00008601	0.00001965
AFUDC_OFF SUBTRAN	0.07093553	0.03233593	0.00137950	0.00521012	0.00009403	0.00001325	0.00574042	0.00111929	0.00043630	-	0.00019392	0.00277564	0.00400409	-	0.01760111	-	0.00003196	-	-
AFUDC_OFF DISTPRI	0.04889661	0.03294625	0.00139485	0.00503910	0.00009026	-	0.00549973	0.00107106	-	-	0.00019961	0.00262429	-	-	-	-	0.00003146	-	-
AFUDC_OFF DISTSEC	0.02400002	0.01781945	0.00097411	0.00247102	-	-	0.00238221	-	-	-	0.00007172	-	-	-	-	-	0.00001168	0.00022222	0.00004760
AFUDC_OFF ENERGY	0.00033351	0.00011851	0.00000748	0.00002640	0.00000047	0.00000005	0.00002941	0.00000568	0.00000169	0.00000003	0.00000118	0.00001676	0.00001717	0.00000328	0.00008832	0.00001446	0.00000020	0.00000198	0.00000043
AFUDC_OFF CUSTOMER	0.01255648	0.00572481	0.00147931	0.00045209	0.00014738	0.00003702	0.00015488	0.00004531	0.00009104	0.00000680	0.00000124	0.00002417	0.00011835	0.00003399	0.00006119	0.00001360	0.00000068	0.00375511	0.00040951
AFUDC_OFF TOTAL	1.00000000	0.48524151	0.02259490	0.07858320	0.00150305	0.00017290	0.08461173	0.01602639	0.00460753	0.00008735	0.00294194	0.03972049	0.04046352	0.00801674	0.18449819	0.02570898	0.00046084	0.00424297	0.00051777
ATR_ADJ PRODUCTION	1.00000000	0.40765617	0.04490892	0.12856702	0.00210254	0.00025254	0.11884939	0.02036735	0.00414497	(0.00001678)	0.00376910	0.04333034	0.04017777	0.00839309	0.13773642	0.01815196	0.00071889	0.01744476	0.00344555
ATR_ADJ BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ TOTAL	1.00000000	0.40765617	0.04490892	0.12856702	0.00210254	0.00025254	0.11884939	0.02036735	0.00414497	(0.00001678)	0.00376910	0.04333034	0.04017777	0.00839309	0.13773642	0.01815196	0.00071889	0.01744476	0.00344555
BULK_TRANS PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS BULKTRAN	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
BULK_TRANS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS TOTAL	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
CUST_902 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 CUSTOMER	1.00000000	0.78889726	0.13589226	0.06163153	0.00083852	0.00009982	0.00970292	0.00106955	0.00028521	0.00001426	0.00010268	0.00068451	0.00044493	0.00008556	0.00015401	0.00003423	0.00006275	-	-
CUST_902 TOTAL	1.00000000	0.78889726	0.13589226	0.06163153	0.00083852	0.00009982	0.00970292	0.00106955	0.00028521	0.00001426	0.00010268	0.00068451	0.00044493	0.00008556	0.00015401	0.00003423	0.00006275	-	-
CUST_903 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 CUSTOMER	1.00000000	0.86074937	0.10325827	0.03122060	0.00036411	0.00004329	0.00327678	0.00032497	0.00008677	0.00000416	0.00002609	0.00017336	0.00011267	0.00002155	0.00003894	0.00000870	0.00004764	-	0.00024274
CUST_903 TOTAL	1.00000000	0.86074937	0.10325827	0.03122060	0.00036411	0.00004329	0.00327678	0.00032497	0.00008677	0.00000416	0.00002609	0.00017336	0.00011267	0.00002155	0.00003894	0.00000870	0.00004764	-	0.00024274
CUST_DEP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP CUSTOMER	1.00000000	0.72944254	0.04391236	0.08643739	0.02180074	0.00367576	0.03714454	0.01517663	0.00616385	0.00136968	-	0.01769325	0.01920157	0.01309038	-	-	-	0.00489131	-
CUST_DEP TOTAL	1.00000000	0.72944254	0.04391236	0.08643739	0.02180074	0.00367576	0.03714454	0.01517663	0.00616385	0.00136968	-	0.01769325	0.01920157	0.01309038	-	-	-	0.00489131	-
CUST_DEP_FXNL PRODUCTION	0.50619222	0.36318092	0.01841118	0.04529657	0.00949740	0.00131779	0.01986386	0.00884911	0.00423363	0.00082204	-	0.01042304	0.01403614	0.01019366	-	-	-	0.00006688	-
CUST_DEP_FXNL BULKTRAN	0.13249897	0.09506487	0.00481924	0.01185666	0.00248600	0.00034494	0.00519949	0.00231631	0.00110818	0.00021517	-	0.00272830	0.00367405	0.00266825	-	-	-	0.00001751	-
CUST_DEP_FXNL SUBTRAN	0.03266922	0.02373734	0.00117194	0.00289123	0.00061090	0.00011410	0.00128999	0.00057554	0.00036277	-	-	0.00067603	0.00123937	-	-	-	-	-	-
CUST_DEP_FXNL DISTPRI	0.18559366	0.14396428	0.00705367	0.01664522	0.00349077	-	0.00735676	0.00327830	-	-	-	0.00380466	-	-	-	-	-	-	-
CUST_DEP_FXNL DISTSEC	0.09435732	0.07782265	0.00492334	0.00815785	-	-	0.00318485	-	-	-	-	-	-	-	-	-	-	0.00026864	-
CUST_DEP_FXNL ENERGY	0.00087235	0.00055853	0.00004078	0.00009404	0.00001978	0.00000279	0.00004243	0.00001876	0.00000902	0.00000175	-	0.00002621	0.00003412	0.00002156	-	-	-	0.00000258	-
CUST_DEP_FXNL CUSTOMER	0.04781626	0.02511396	0.00749221	0.00149580	0.00569589	0.00189614	0.00020717	0.00013861	0.00045024	0.00033072	-	0.00003502	0.00021789	0.00020690	-	-	-	0.00453570	-
CUST_DEP_FXNL TOTAL	1.00000000	0.72944254	0.04391236	0.08643739	0.02180074	0.00367576	0.03714454	0.01517663	0.00616385	0.00136968	-	0.01769325	0.01920157	0.01309038	-	-	-	0.00489131	-
CUST_TOTAL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL CUSTOMER	1.00000000	0.63445897	0.10928934	0.03304416	0.00038535	0.00004588	0.00346819	0.00034407	0.00009175	0.00000459	0.00002753	0.00018350	0.00011928	0.00002294	0.00004129	0.00000918	0.00005046	0.21815663	0.00025690
CUST_TOTAL TOTAL	1.00000000	0.63445897	0.10928934	0.03304416	0.00038535	0.00004588	0.00346819	0.00034407	0.00009175	0.00000459	0.00002753	0.00018350	0.00011928	0.00002294	0.00004129	0.00000918	0.00005046	0.21815663	0.00025690
DIST_CPD PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD DISTPRI	1.00000000	0.67379424	0.02852657	0.10305620	0.00184593	-	0.11247677	0.02190449	-	-	0.00408226	0.05367011	-	-	-	-	0.00064343	-	-
DIST_CPD DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD TOTAL	1.00000000	0.67379424	0.02852657	0.10305620	0.00184593	-	0.11247677	0.02190449	-	-	0.00408226	0.05367011	-	-	-	-	0.00064343	-	-
DIST_METERS PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS CUSTOMER	1.00000000	0.42788828	0.24956426	0.07687456	0.05091223	0.01279846	0.04519346	0.01560371	0.03147652	0.00235116	0.00036223	0.00832198	0.04091946	0.01175577	0.02116037	0.00470230	0.00011524	-	-
DIST_METERS TOTAL	1.00000000	0.42788828	0.24956426	0.07687456	0.05091223	0.01279846	0.04519346	0.01560371	0.03147652	0.00235116	0.00036223	0.00832198	0.04091946	0.01175577	0.02116037	0.00470230	0.00011524	-	-

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	QP-SEC 11	QP-PRI 12	QP-SUB 13	QP-TRA 14	CIP-TOD-SUB 15	CIP-TOD-TRA 16	MW 17	OL 18	SL 19
DIST_OHLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES DISTPRI	0.86460000	0.58256250	0.02466407	0.08910239	0.00159599	-	0.09724741	0.01893862	-	-	0.00352952	0.04640317	-	-	-	-	0.00055631	-	-
DIST_OHLINES DISTSEC	0.13540000	0.10053133	0.00549562	0.01394066	-	-	0.01343964	-	-	-	0.00040462	-	-	-	-	-	0.00006591	0.00125371	0.00026853
DIST_OHLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES TOTAL	1.00000000	0.68309383	0.03015970	0.10304305	0.00159599	-	0.11068705	0.01893862	-	-	0.00393414	0.04640317	-	-	-	-	0.00062221	0.00125371	0.00026853
DIST_OL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL CUSTOMER	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIST_OL TOTAL	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIST_PCUST PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST CUSTOMER	1.00000000	0.63467151	0.10932595	0.03305523	0.00038548	-	0.00346935	0.00034418	-	-	0.00002753	0.00018356	-	-	-	-	0.00005048	0.21822971	0.00025699
DIST_PCUST TOTAL	1.00000000	0.63467151	0.10932595	0.03305523	0.00038548	-	0.00346935	0.00034418	-	-	0.00002753	0.00018356	-	-	-	-	0.00005048	0.21822971	0.00025699
DIST_POLES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES DISTPRI	0.56150000	0.37833547	0.01601767	0.05786606	0.00103649	-	0.06315570	0.01229937	-	-	0.00229219	0.03013576	-	-	-	-	0.00036128	-	-
DIST_POLES DISTSEC	0.43850000	0.32557597	0.01779787	0.04514755	-	-	0.04352496	-	-	-	0.00131037	-	-	-	-	-	0.00021344	0.00406021	0.00086963
DIST_POLES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES TOTAL	1.00000000	0.70391144	0.03381554	0.10301360	0.00103649	-	0.10668067	0.01229937	-	-	0.00360256	0.03013576	-	-	-	-	0.00057472	0.00406021	0.00086963
DIST_SERV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV CUSTOMER	1.00000000	0.63525164	0.10942589	0.03308545	-	-	0.00347253	-	-	-	0.00002756	-	-	-	-	-	0.00005053	0.21842919	0.00025722
DIST_SERV TOTAL	1.00000000	0.63525164	0.10942589	0.03308545	-	-	0.00347253	-	-	-	0.00002756	-	-	-	-	-	0.00005053	0.21842919	0.00025722
DIST_SL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL CUSTOMER	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_SL TOTAL	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_TRANSF PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF DISTPRI	0.24980000	0.16831380	0.00712594	0.02574344	0.00046111	-	0.02809670	0.00547174	-	-	0.00101975	0.01340679	-	-	-	-	0.00016073	-	-
DIST_TRANSF DISTSEC	0.75020000	0.55700591	0.03044917	0.07723988	-	-	0.07446392	-	-	-	0.00224182	-	-	-	-	-	0.00036515	0.00694634	0.00148780
DIST_TRANSF ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF TOTAL	1.00000000	0.72531971	0.03757511	0.10298332	0.00046111	-	0.10256061	0.00547174	-	-	0.00326157	0.01340679	-	-	-	-	0.00052588	0.00694634	0.00148780
DIST_UGLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES DISTPRI	0.72760000	0.49025269	0.02075593	0.07498369	0.00134310	-	0.08183810	0.01593771	-	-	0.00297025	0.03905037	-	-	-	-	0.00046816	-	-
DIST_UGLINES DISTSEC	0.27240000	0.20225061	0.01105619	0.02804605	-	-	0.02703808	-	-	-	0.00081401	-	-	-	-	-	0.00013259	0.00252224	0.00054022
DIST_UGLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES TOTAL	1.00000000	0.69250331	0.03181212	0.10302974	0.00134310	-	0.10887618	0.01593771	-	-	0.00378426	0.03905037	-	-	-	-	0.00060075	0.00252224	0.00054022
EXP_OM_AG_REG PRODUCTION	0.56323941	0.20895270	0.01433999	0.05356864	0.00081514	0.00007922	0.05365965	0.00862695	0.00328525	0.00007280	0.00192511	0.02586730	0.03016784	0.00508996	0.13121059	0.02497085	0.00034190	0.00019664	0.00006888
EXP_OM_AG_REG BULKTRAN	0.14743142	0.05469467	0.00375358	0.01402193	0.00021337	0.00002074	0.01404575	0.00225816	0.00085994	0.00001906	0.00050391	0.00677093	0.00789662	0.00133233	0.03434519	0.00653627	0.00008949	0.00005147	0.00001803
EXP_OM_AG_REG SUBTRAN	0.03795495	0.01365705	0.00091279	0.00341923	0.00005243	0.00000686	0.00348474	0.00056109	0.00028151	-	0.00012085	0.00167773	0.00266378	-	0.01109413	-	0.00002274	-	-
EXP_OM_AG_REG DISTPRI	0.14169228	0.08282848	0.00549392	0.01968498	0.00029961	-	0.01987334	0.00319600	-	-	0.00074051	0.00944217	-	-	-	-	0.00013327	-	-
EXP_OM_AG_REG DISTSEC	0.06822485	0.04477452	0.00383466	0.00964764	-	-	0.00860345	-	-	-	0.00026592	-	-	-	-	-	0.00004946	0.00078982	0.00025938
EXP_OM_AG_REG ENERGY	0.00120088	0.00032134	0.00003177	0.00011122	0.00000170	0.00000017	0.00011463	0.00001829	0.00000700	0.00000015	0.00000471	0.00006505	0.00007334	0.00001077	0.00035740	0.00007233	0.00000093	0.00000758	0.00000253
EXP_OM_AG_REG CUSTOMER	0.04025622	0.01444908	0.00583549	0.00176897	0.00048887	0.00011399	0.00055964	0.00013513	0.00034938	0.00002929	0.00000460	0.00008692	0.00046832	0.00010331	0.00022940	0.00006299	0.00000290	0.01333533	0.00223261
EXP_OM_AG_REG TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
EXP_OM_CUSTACCT PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT CUSTOMER	1.00000000	0.85558580	0.10631437	0.03409641	0.00040902	0.00004864	0.00388589	0.00039557	0.00010559	0.00000512	0.00003335	0.00022185	0.00014419	0.00002762	0.00004986	0.00001112	0.00004905	(0.00160304)	0.00021957
EXP_OM_CUSTACCT TOTAL	1.00000000	0.85558580	0.10631437	0.03409641	0.00040902	0.00004864	0.00388589	0.00039557	0.00010559	0.00000512	0.00003335	0.00022185	0.00014419	0.00002762	0.00004986	0.00001112	0.00004905	(0.00160304)	0.00021957

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	QP-SEC 11	QP-PRI 12	QP-SUB 13	QP-TRA 14	CIP-TOD-SUB 15	CIP-TOD-TRA 16	MW 17	OL 18	SL 19
EXP_OM_CUSTSERV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV CUSTOMER	1.00000000	0.63445897	0.10928934	0.03304416	0.00038535	0.00004588	0.00346819	0.00034407	0.00009175	0.00000459	0.00002753	0.00018350	0.00011928	0.00002294	0.00004129	0.00000918	0.00005046	0.21815663	0.00025690
EXP_OM_CUSTSERV TOTAL	1.00000000	0.63445897	0.10928934	0.03304416	0.00038535	0.00004588	0.00346819	0.00034407	0.00009175	0.00000459	0.00002753	0.00018350	0.00011928	0.00002294	0.00004129	0.00000918	0.00005046	0.21815663	0.00025690
EXP_OM_DIST PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST DISTPRI	0.67817526	0.45695059	0.01934601	0.06989017	0.00125186	-	0.07627896	0.01485509	-	-	0.00276849	0.03639774	-	-	-	-	0.00043636	-	-
EXP_OM_DIST DISTSEC	0.26518074	0.19689048	0.01076317	0.02730276	-	-	0.02632151	-	-	-	0.00079244	-	-	-	-	-	0.00012907	0.00245539	0.00052591
EXP_OM_DIST ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST CUSTOMER	0.05664400	0.02158935	0.00858785	0.00263583	0.00141141	0.00035435	0.00130452	0.00043363	0.00087149	0.00006510	0.00001045	0.00023127	0.00113293	0.00032548	0.00058586	0.00013019	0.00000397	0.01153113	0.00543919
EXP_OM_DIST TOTAL	1.00000000	0.67543042	0.03869704	0.09982875	0.00266327	0.00035435	0.10390499	0.01528872	0.00087149	0.00006510	0.00357138	0.03662901	0.00113293	0.00032548	0.00058586	0.00013019	0.00056940	0.01398652	0.00596509
EXP_OM_SS PRODUCTION	0.00236154	0.00110980	0.00004861	0.00018310	0.00000328	0.00000034	0.00019828	0.00003860	0.00001142	0.00000023	0.00000693	0.00009600	0.00010172	0.00002235	0.00046697	0.00007192	0.00000108	0.00000074	0.00000017
EXP_OM_SS BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS ENERGY	0.99763846	0.35450248	0.02236775	0.07895978	0.00141812	0.00015104	0.08797937	0.01699512	0.00505691	0.00009944	0.00351842	0.05014469	0.05136477	0.00981664	0.26419616	0.04326654	0.00060639	0.00590907	0.00128576
EXP_OM_SS CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS TOTAL	1.00000000	0.35561228	0.02241636	0.07914289	0.00142140	0.00015139	0.08817766	0.01703373	0.00506833	0.00009967	0.00352535	0.05024069	0.05146649	0.00983899	0.26466312	0.04333846	0.00060746	0.00590981	0.00128592
EXP_OM_TRAN PRODUCTION	0.53249320	0.25024400	0.01096186	0.04128744	0.00073938	0.00007740	0.04471032	0.00870467	0.00257540	0.00005084	0.00156240	0.02164610	0.02293697	0.00503869	0.10529382	0.01621638	0.00024302	0.00016649	0.00003804
EXP_OM_TRAN BULKTRAN	0.37166791	0.17466451	0.00765113	0.02881768	0.00051607	0.00005403	0.03120677	0.00607565	0.00179757	0.00003549	0.00109052	0.01510847	0.01600947	0.00351689	0.07349265	0.01131866	0.00016962	0.00011620	0.00002655
EXP_OM_TRAN SUBTRAN	0.09583889	0.04368812	0.00186380	0.00703924	0.00012703	0.00001790	0.00775571	0.00151224	0.00058947	-	0.00026199	0.00375008	0.00540980	-	0.02378033	-	0.00004318	-	-
EXP_OM_TRAN DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN TOTAL	1.00000000	0.46859663	0.02047678	0.07714436	0.00138248	0.00014933	0.08367280	0.01629256	0.00496243	0.00008633	0.00291491	0.04050465	0.04435624	0.00855557	0.20256680	0.02753504	0.00045581	0.00028269	0.00006458
EXP_OM PRODUCTION	0.48244003	0.22667652	0.00993369	0.03741452	0.00066990	0.00007013	0.04051281	0.00788598	0.00233377	0.00004608	0.00141576	0.01961382	0.02078572	0.00456487	0.09541249	0.01469840	0.00022024	0.00015085	0.00003448
EXP_OM BULKTRAN	(0.11392060)	(0.05354854)	(0.00234458)	(0.00883086)	(0.00015817)	(0.00001656)	(0.00956389)	(0.00186238)	(0.00055086)	(0.00001087)	(0.00033420)	(0.00463030)	(0.00490584)	(0.00107802)	(0.02252216)	(0.00346765)	(0.00005197)	(0.00003561)	(0.00000813)
EXP_OM SUBTRAN	(0.02937580)	(0.01339390)	(0.00057114)	(0.00215710)	(0.00003894)	(0.00000549)	(0.00237688)	(0.00046355)	(0.00018064)	-	(0.00008029)	(0.00114929)	(0.00165775)	-	(0.00728761)	-	(0.00001323)	-	-
EXP_OM DISTPRI	0.10127255	0.06822663	0.00289013	0.01044088	0.00018697	-	0.01139399	0.00221840	-	-	0.00041355	0.00543680	-	-	-	-	0.00006520	-	-
EXP_OM DISTSEC	0.03961006	0.02940479	0.00160856	0.00408034	-	-	0.00393313	-	-	-	0.00011842	-	-	-	-	-	0.00001929	0.00036689	0.00007866
EXP_OM ENERGY	0.48330624	0.17173874	0.01083607	0.03825210	0.00068701	0.00007317	0.04262164	0.00823329	0.00244982	0.00004817	0.00170450	0.02429261	0.02488369	0.00475568	0.12798994	0.02096050	0.00029376	0.00286265	0.00062289
EXP_OM CUSTOMER	0.03666752	0.02580623	0.00430299	0.00134830	0.00022229	0.00005430	0.00030165	0.00007558	0.00013315	0.00000987	0.00000246	0.00004055	0.00017326	0.00004938	0.00008892	0.00001977	0.00000199	0.00321724	0.00081957
EXP_OM TOTAL	1.00000000	0.45491048	0.02665573	0.08054817	0.00156906	0.00017555	0.08682244	0.01608732	0.00418525	0.00009325	0.00324020	0.04360419	0.03927908	0.00829190	0.19368157	0.03221103	0.00053528	0.00656202	0.00154747
EXP_OTHTAX_PSC PRODUCTION	0.31439089	0.10753205	0.00681395	0.02803525	0.00027619	0.00001919	0.02863329	0.00475984	0.00195766	0.00002470	0.00103055	0.01426005	0.01882963	0.00330583	0.08236427	0.01626881	0.00018114	0.00007285	0.00002566
EXP_OTHTAX_PSC BULKTRAN	0.22059642	0.07674515	0.00488140	0.01979200	0.00030260	0.00002812	0.01988414	0.00330247	0.00141202	0.00003347	0.00071120	0.00992106	0.01314808	0.00237664	0.05661016	0.01125398	0.00012460	0.00005160	0.00001773
EXP_OTHTAX_PSC SUBTRAN	0.05704768	0.01922755	0.00119107	0.00484243	0.00007466	0.00000934	0.00494963	0.00082333	0.00046380	-	0.00017113	0.00246645	0.00445004	-	0.01834648	-	0.00003177	-	-
EXP_OTHTAX_PSC DISTPRI	0.20126525	0.11721146	0.00721321	0.02804961	0.00042884	-	0.02840668	0.00475209	-	-	0.00105310	0.01396302	-	-	-	-	0.00018724	-	-
EXP_OTHTAX_PSC DISTSEC	0.09557978	0.06312651	0.00501546	0.01369508	-	-	0.01225120	-	-	-	0.00037682	-	-	-	-	-	0.00006923	0.00078955	0.00025594
EXP_OTHTAX_PSC ENERGY	0.06064753	0.01507594	0.00140057	0.00527805	0.00009550	0.00000974	0.00541978	0.00095841	0.00037693	0.00001161	0.00021629	0.00317181	0.00406170	0.00066900	0.01953720	0.00401134	0.00004262	0.00023058	0.00008046
EXP_OTHTAX_PSC CUSTOMER	0.05047244	0.02075918	0.00768654	0.00253019	0.00069332	0.00015457	0.00079648	0.00019948	0.00057267	0.00005152	0.00000652	0.00012770	0.00078045	0.00018490	0.00037861	0.00010832	0.00000408	0.01323625	0.00220165
EXP_OTHTAX_PSC TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
FORF_DISC PRODUCTION	1.00000000	0.71112214	0.06620871	0.12269002	0.00178294	0.00066684	0.04297993	0.00580371	0.00223445	0.00021246	0.00214966	0.01012398	0.01530002	0.00447882	0.00857472	-	-	0.00567159	-
FORF_DISC BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC TOTAL	1.00000000	0.71112214	0.06620871	0.12269002	0.00178294	0.00066684	0.04297993	0.00580371	0.00223445	0.00021246	0.00214966	0.01012398	0.01530002	0.00447882	0.00857472	-	-	0.00567159	-
FORF_DISC_FXNL PRODUCTION	0.34060038	0.24942388	0.01693756	0.03998340	0.00047287	0.00014971	0.01434404	0.00218543	0.00093251	0.00006368	0.00067985	0.00341080	0.00646450	0.00200850	0.00336851	-	-	0.00017515	-
FORF_DISC_FXNL BULKTRAN	(0.00983515)	(0.01645584)	0.00144537	0.00401491	0.00002268	0.00000691	0.00077044	(0.00009745)	0.00010491	0.00001625	0.00002670	0.00001342	0.00051429	(0.00019118)	(0.00003210)	-	-	0.00000554	-
FORF_DISC_FXNL SUBTRAN	(0.00239813)	(0.00411783)	0.00035294	0.00098290	0.00000561	0.00000230	0.00019201	(0.00002423)	0.00003447	(0.00000000)	0.00000643	0.00000339	0.00017419	(0.00000000)	(0.00001033)	-	-	(0.00000000)	-
FORF_DISC_FXNL DISTPRI	0.19018732	0.14292360	0.01050052	0.02452425	0.00029984	(0.00000000)	0.00847601	0.00113145	(0.00000000)	(0.00000000)	0.00041615	0.00191551	(0.00000000)	(0.00000000)	(0.00000000)	-	-	(0.00000000)	-
FORF_DISC_FXNL DISTSEC	0.08764130	0.06640136	0.00662396	0.01090286	(0.00000000)	(0.00000000)	0.00328560	(0.00000000)	(0.00000000)	(0.00000000)	0.00013303	(0.00000000)	(0.00000000)	(0.00000000)	(0.00000000)	-	-	0.00029450	-
FORF_DISC_FXNL ENERGY	0.33499615	0.23462158	0.01803482	0.03983093	0.00056571	0.00018795	0.01568813	0.00256735	0.00101063	0.00007712	0.00088507	0.00476548	0.00800301	0.00261777	0.00524120	-	-	0.00089940	-
FORF_DISC_FXNL CUSTOMER	0.05880813	0.03832539	0.01231355	0.00245076	0.00041623	0.00031997	0.00022371	0.00004115	0.00015194	0.00005541	0.00000243	0.00001537	0.00014404	0.00004373	0.00000743	-	-	0.00429701	-
FORF_DISC_FXNL TOTAL	1.00000000	0.71112214	0.06620871	0.12269002	0.00178294	0.00066684	0.04297993	0.00580371	0.00223445	0.00021246	0.00214966	0.01012398	0.01530002	0.00447882	0.00857472	-	-	0.00567159	-
FUELREV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV ENERGY	1.00000000	0.35720720	0.02166932	0.07650617	0.00148466	0.00015896	0.08458175	0.01369288	0.00559711	0.00010266	0.00356425	0.05053996	0.05259031	0.00927104	0.26629823	0.04833319	0.00058969	0.00650972	0.00130290
FUELREV CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV TOTAL	1.00000000	0.35720720	0.02166932	0.07650617	0.00148466	0.00015896	0.08458175	0.01369288	0.00559711	0.00010266	0.00356425	0.05053996	0.05259031	0.00927104	0.26629823	0.04833319	0.00058969	0.00650972	0.00130290
LABOR_M PRODUCTION	0.43108943	0.20258952	0.00887437	0.03342499	0.00059858	0.00006266	0.03619605	0.00704702	0.00208496	0.00004116	0.00126487	0.01752399	0.01856903	0.00407916	0.08524250	0.01312826	0.00019674	0.00013478	0.00003079
LABOR_M BULKTRAN	0.01873309	0.00880357	0.00038564	0.00145249	0.00002601	0.00000272	0.00157291	0.00030623	0.00009060	0.00000179	0.00005497	0.00076151	0.00080692	0.00017726	0.00370423	0.00057049	0.00000855	0.00000586	0.00000134
LABOR_M SUBTRAN	0.00483055	0.00220200	0.00009394	0.00035480	0.00000640	0.00000090	0.00039091	0.00007622	0.00002971	-	0.00001321	0.00018901	0.00027267	-	0.00119859	-	0.00000218	-	-
LABOR_M DISTPRI	0.27182362	0.18315319	0.00775420	0.02801311	0.00050177	-	0.03057384	0.00595416	-	-	0.00110965	0.01458880	-	-	-	-	0.00017490	-	-
LABOR_M DISTSEC	0.10628873	0.07891689	0.00431405	0.01094339	-	-	0.01055009	-	-	-	0.00031762	-	-	-	-	-	0.00005174	0.00098416	0.00021079
LABOR_M ENERGY	0.05612117	0.01994219	0.00125828	0.00444180	0.00007978	0.00000850	0.00494919	0.00095604	0.00028447	0.00000559	0.00019793	0.00282084	0.00288947	0.00055223	0.01486209	0.00243392	0.00003411	0.00033241	0.00007233
LABOR_M CUSTOMER	0.11111342	0.07848128	0.01291958	0.00404327	0.00060125	0.00014626	0.00085544	0.00020742	0.00035828	0.00002653	0.00000698	0.00011130	0.00046619	0.00013278	0.00023901	0.00005311	0.00000596	0.01025827	0.00220051
LABOR_M TOTAL	1.00000000	0.57408864	0.03560006	0.08267384	0.00181379	0.00022104	0.08508842	0.01454710	0.00284802	0.00007507	0.00296522	0.03599546	0.02300429	0.00494142	0.10524643	0.01618579	0.00047417	0.01171547	0.00251576

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	QP-SEC 11	QP-PRI 12	QP-SUB 13	QP-TRA 14	CIP-TOD-SUB 15	CIP-TOD-TRA 16	MW 17	OL 18	SL 19
LABOR_TD PRODUCTION	0.05948139	0.02795315	0.00122448	0.00461195	0.00008259	0.00000865	0.00499430	0.00097234	0.00028768	0.00000568	0.00017453	0.00241795	0.00256214	0.00056284	0.01176170	0.00181143	0.00002715	0.00001860	0.00000425
LABOR_TD BULKTRAN	0.04151663	0.01951065	0.00085466	0.00321904	0.00005765	0.00000603	0.00348591	0.00067867	0.00020079	0.00000396	0.00012181	0.00168767	0.00178832	0.00039285	0.00820939	0.00126433	0.00001895	0.00001298	0.00000297
LABOR_TD SUBTRAN	0.01070555	0.00488012	0.00020819	0.00078631	0.00001419	0.00000200	0.00086634	0.00016892	0.00006585	-	0.00002927	0.00041890	0.00060429	-	0.00265635	-	0.00000482	-	-
LABOR_TD DISTPRI	0.60242066	0.40590757	0.01718500	0.06208319	0.00111203	-	0.06775833	0.01319572	-	-	0.00245924	0.03233198	-	-	-	-	0.00038761	-	-
LABOR_TD DISTSEC	0.23555910	0.17489711	0.00956089	0.02425294	-	-	0.02338130	-	-	-	0.00070392	-	-	-	-	-	0.00011466	0.00218112	0.00046716
LABOR_TD ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_TD CUSTOMER	0.05031667	0.01917775	0.00762856	0.00234140	0.00125375	0.00031477	0.00115880	0.00038519	0.00077414	0.00005782	0.00000928	0.00020544	0.00100638	0.00028912	0.00052042	0.00011565	0.00000352	0.01024306	0.00483161
LABOR_TD TOTAL	1.00000000	0.65232635	0.03666177	0.09729483	0.00252020	0.00033145	0.10164498	0.01540085	0.00132846	0.00006747	0.00349805	0.03706193	0.00596113	0.00124481	0.02314786	0.00319141	0.00055671	0.01245575	0.00530598
PROD_DEMAND PRODUCTION	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
PROD_DEMAND BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND TOTAL	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
PROD_ENERGY PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY ENERGY	1.00000000	0.35534163	0.02242070	0.07914669	0.00142148	0.00015140	0.08818763	0.01703535	0.00506888	0.00009968	0.00352675	0.05026339	0.05148636	0.00983988	0.26482155	0.04336896	0.00060782	0.00592306	0.00128880
PROD_ENERGY CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY TOTAL	1.00000000	0.35534163	0.02242070	0.07914669	0.00142148	0.00015140	0.08818763	0.01703535	0.00506888	0.00009968	0.00352675	0.05026339	0.05148636	0.00983988	0.26482155	0.04336896	0.00060782	0.00592306	0.00128880
LABOR_PROD PRODUCTION	0.87809590	0.41265922	0.01807641	0.06808412	0.00121925	0.00012764	0.07372855	0.01435423	0.00424690	0.00008384	0.00257644	0.03569501	0.03782369	0.00830893	0.17363240	0.02674126	0.00040074	0.00027454	0.00006272
LABOR_PROD BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD ENERGY	0.12190410	0.04331760	0.00273318	0.00964831	0.00017328	0.00001846	0.01075043	0.00207668	0.00061792	0.00001215	0.00042993	0.00612731	0.00627640	0.00119952	0.03228283	0.00528685	0.00007410	0.00072204	0.00015711
LABOR_PROD CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD TOTAL	1.00000000	0.45597682	0.02080959	0.07773243	0.00139254	0.00014610	0.08447899	0.01643091	0.00486482	0.00009599	0.00300636	0.04182232	0.04410009	0.00950845	0.20591523	0.03202811	0.00047484	0.00099658	0.00021983
RATEBASE PRODUCTION	0.29647495	0.13645765	0.00593330	0.02287178	0.00021891	0.00001587	0.02541521	0.00489317	0.00138788	0.00001144	0.00090041	0.01227820	0.01294035	0.00270029	0.06086557	0.00932926	0.00014040	0.00009333	0.00002190
RATEBASE BULKTRAN	0.20871639	0.09738921	0.00425051	0.01614675	0.00023985	0.00002326	0.01764937	0.00339498	0.00100106	0.00001551	0.00062139	0.00854225	0.00903580	0.00194131	0.04183379	0.00645353	0.00009657	0.00006611	0.00001513
RATEBASE SUBTRAN	0.05393653	0.02439967	0.00103713	0.00395057	0.00005918	0.00000773	0.00439334	0.00084639	0.00032881	-	0.00014952	0.00212367	0.00305821	-	0.01355769	-	0.00002462	-	-
RATEBASE DISTPRI	0.22143212	0.14874077	0.00628096	0.02288350	0.00033991	-	0.02521407	0.00488521	-	-	0.00092011	0.01202245	-	-	-	-	0.00014513	-	-
RATEBASE DISTSEC	0.10813435	0.08010723	0.00436725	0.01117275	-	-	0.01087430	-	-	-	0.00032924	-	-	-	-	-	0.00005366	0.00101147	0.00021845
RATEBASE ENERGY	0.05420183	0.01913129	0.00121956	0.00430595	0.00007569	0.00000806	0.00481065	0.00098526	0.00026723	0.00000538	0.00018898	0.00273100	0.00279133	0.00054646	0.01443761	0.00230028	0.00003303	0.00029539	0.00006867
RATEBASE CUSTOMER	0.05710383	0.02634330	0.00669311	0.00206418	0.00054955	0.00012783	0.00070697	0.00020507	0.00040599	0.00002387	0.00000570	0.00010996	0.00053635	0.00015103	0.00027979	0.00006211	0.00000317	0.01695662	0.00187923
RATEBASE TOTAL	1.00000000	0.53256912	0.02978183	0.08339548	0.00148310	0.00018275	0.08906391	0.01521009	0.00339097	0.00005620	0.00311536	0.03780752	0.02836205	0.00533909	0.13097445	0.01814519	0.00049657	0.01842292	0.00220339
RB_GUP_CWIP PRODUCTION	0.40868804	0.19206204	0.00841322	0.03168807	0.00056747	0.00005941	0.03431513	0.00668082	0.00197661	0.00003902	0.00119914	0.01661336	0.01760410	0.00386719	0.08081291	0.01244606	0.00018651	0.00012778	0.00002919
RB_GUP_CWIP BULKTRAN	0.37326318	0.17541420	0.00768397	0.02894137	0.00051828	0.00005426	0.03134072	0.00610173	0.00180528	0.00003564	0.00109520	0.01517332	0.01607819	0.00353198	0.07380809	0.01136724	0.00017035	0.00011670	0.00002666
RB_GUP_CWIP SUBTRAN	0.09625025	0.04387564	0.00187180	0.00706946	0.00012758	0.00001798	0.00778899	0.00151873	0.00059200	-	0.00026312	0.00376618	0.00543302	-	0.02388240	-	0.00004336	-	-
RB_GUP_CWIP DISTPRI	0.06909643	0.04655678	0.00197108	0.00712082	0.00012755	-	0.00777174	0.00151352	-	-	0.00028207	0.00370841	-	-	-	-	0.00004446	-	-
RB_GUP_CWIP DISTSEC	0.03368788	0.02501246	0.00136733	0.00346847	-	-	0.00334382	-	-	-	0.00010067	-	-	-	-	-	0.00001640	0.00031193	0.00006681
RB_GUP_CWIP ENERGY	0.00092505	0.00032871	0.00002074	0.00007321	0.00000131	0.00000014	0.00008158	0.00001576	0.00000469	0.00000009	0.00000326	0.00004650	0.00004763	0.00000910	0.00024497	0.00004012	0.00000056	0.00000548	0.00000119
RB_GUP_CWIP CUSTOMER	0.01808916	0.00847993	0.00212969	0.00065165	0.00020644	0.00005182	0.00021881	0.00006365	0.00012741	0.00000951	0.00000175	0.00003396	0.00016564	0.00004757	0.00008562	0.00001903	0.00000098	0.00521762	0.00057805
RB_GUP_CWIP TOTAL	1.00000000	0.49172976	0.02345783	0.07901305	0.00154864	0.00018360	0.08486079	0.01589422	0.00450599	0.00008426	0.00294521	0.03934173	0.03932858	0.00745584	0.17883400	0.02387244	0.00046263	0.00577951	0.00070190
RB_GUP_EPIS_D PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D DISTPRI	0.57278802	0.38594127	0.01633968	0.05902936	0.00105733	-	0.06442534	0.01254663	-	-	0.00233827	0.03074159	-	-	-	-	0.00036855	-	-
RB_GUP_EPIS_D DISTSEC	0.28309593	0.21019209	0.01149032	0.02914729	-	-	0.02809975	-	-	-	0.00084598	-	-	-	-	-	0.00013780	0.00262128	0.00056144
RB_GUP_EPIS_D ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D CUSTOMER	0.14411605	0.06370307	0.01699094	0.00518580	0.00174217	0.00043795	0.00181467	0.00053394	0.00107710	0.00008045	0.00001452	0.00028477	0.00140023	0.00040227	0.00072409	0.00016091	0.00000785	0.04475275	0.00480257
RB_GUP_EPIS_D TOTAL	1.00000000	0.65983643	0.04482093	0.09336245	0.00279950	0.00043795	0.09433976	0.01308058	0.00107710	0.00008045	0.00319877	0.03102637	0.00140023	0.00040227	0.00072409	0.00016091	0.00051419	0.04737403	0.00536400
RB_GUP_EPIS_G PRODUCTION	0.43108943	0.20258952	0.00887437	0.03342499	0.00059858	0.00006266	0.03619605	0.00704702	0.00208496	0.00004116	0.00126487	0.01752399	0.01856903	0.00407916	0.08524250	0.01312826	0.00019674	0.00013478	0.00003079
RB_GUP_EPIS_G BULKTRAN	0.01873309	0.00880357	0.00038564	0.00145249	0.00002601	0.00000272	0.00157291	0.00030623	0.00009060	0.00000179	0.00005497	0.00076151	0.00080692	0.00017726	0.00370423	0.00057049	0.00000855	0.00000586	0.00000134
RB_GUP_EPIS_G SUBTRAN	0.00483055	0.00220200	0.00009394	0.00035480	0.00000640	0.00000090	0.00039091	0.00007622	0.00002971	-	0.00001321	0.00018901	0.00027267	-	0.00119859	-	0.00000218	-	-
RB_GUP_EPIS_G DISTPRI	0.27182362	0.18315319	0.00775420	0.02801311	0.00050177	-	0.03057384	0.00595416	-	-	0.00110965	0.01458880	-	-	-	-	0.00017490	-	-
RB_GUP_EPIS_G DISTSEC	0.10628873	0.07891689	0.00431405	0.01094339	-	-	0.01055009	-	-	-	0.00031762	-	-	-	-	-	0.00005174	0.00098416	0.00021079
RB_GUP_EPIS_G ENERGY	0.05612117	0.01994219	0.00125828	0.00444180	0.00007978	0.00000850	0.00494919	0.00095604	0.00028447	0.00000559	0.00019793	0.00282084	0.00288947	0.00055223	0.01486209	0.00243392	0.00003411	0.00033241	0.00007233
RB_GUP_EPIS_G CUSTOMER	0.11111342	0.07848128	0.01291958	0.00404327	0.00060125	0.00014626	0.00085544	0.00020742	0.00035828	0.00002653	0.00000698	0.00011130	0.00046619	0.00013278	0.00023901	0.00005311	0.00000596	0.01025827	0.00220051
RB_GUP_EPIS_G TOTAL	1.00000000	0.57408864	0.03560006	0.08267384	0.00181379	0.00022104	0.08508842	0.01454710	0.00284802	0.00007507	0.00296522	0.03599546	0.02300429	0.00494142	0.10524643	0.01618579	0.00047417	0.01171547	0.00251576
RB_GUP_EPIS_P PRODUCTION	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
RB_GUP_EPIS_P BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P TOTAL	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
RB_GUP_EPIS_T PRODUCTION	0.02148003	0.01009449	0.00044219	0.00166548	0.00002983	0.00000312	0.00180355	0.00035113	0.00010389	0.00000205	0.00006302	0.00087317	0.00092525	0.00020325	0.00424741	0.00065415	0.00000980	0.00000672	0.00000153
RB_GUP_EPIS_T BULKTRAN	0.77792338	0.36558337	0.01601427	0.06031714	0.00108016	0.00011308	0.06531765	0.01271671	0.00376242	0.00007427	0.00228252	0.03162295	0.03350879	0.00736106	0.15382455	0.02369064	0.00035502	0.00024322	0.00005557
RB_GUP_EPIS_T SUBTRAN	0.20059659	0.09144188	0.00390104	0.01473356	0.00026589	0.00003747	0.01623316	0.00316520	0.00123379	-	0.00054837	0.00784915	0.01132304	-	0.04977368	-	0.00009037	-	-
RB_GUP_EPIS_T DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T TOTAL	1.00000000	0.46711974	0.02035749	0.07671618	0.00137588	0.00015367	0.08335436	0.01623305	0.00510009	0.00007633	0.00289391	0.04034527	0.04575708	0.00756431	0.20784563	0.02434478	0.00045520	0.00024994	0.00005710

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	QP-SEC 11	QP-PRI 12	QP-SUB 13	QP-TRA 14	CIP-TOD-SUB 15	CIP-TOD-TRA 16	MW 17	OL 18	SL 19
RB_GUP_EPIS PRODUCTION	0.55115145	0.25901240	0.01134596	0.04273413	0.00076529	0.00008012	0.04627695	0.00900967	0.00266564	0.00005262	0.00161714	0.02240456	0.02374066	0.00521524	0.10898325	0.01678459	0.00025153	0.00017232	0.00003937
RB_GUP_EPIS BULKTRAN	0.14426732	0.06779811	0.00296988	0.01118592	0.00020032	0.00002097	0.01211328	0.00235834	0.00069775	0.00001377	0.00042330	0.00586453	0.00621427	0.00136512	0.02852705	0.00439347	0.00006584	0.00004511	0.00001030
RB_GUP_EPIS SUBTRAN	0.03713710	0.01692893	0.00072221	0.00272767	0.00004923	0.00000694	0.00300530	0.00058598	0.00022842	-	0.00010152	0.00145314	0.00209627	-	0.00921476	-	0.00001673	-	-
RB_GUP_EPIS DISTPRI	0.15237895	0.10267206	0.00434685	0.01570360	0.00028128	-	0.01713909	0.00333778	-	-	0.00062205	0.00817819	-	-	-	-	0.00009804	-	-
RB_GUP_EPIS DISTSEC	0.07475165	0.05550135	0.00303403	0.00769636	-	-	0.00741976	-	-	-	0.00022338	-	-	-	-	-	0.00003638	0.00069215	0.00014825
RB_GUP_EPIS ENERGY	0.00112097	0.00039833	0.00002513	0.00008872	0.00000159	0.00000017	0.00009886	0.00001910	0.00000568	0.00000011	0.00000395	0.00005634	0.00005771	0.00001103	0.00029686	0.00004862	0.00000068	0.00000664	0.00000144
RB_GUP_EPIS CUSTOMER	0.03919256	0.01791070	0.00461710	0.00141118	0.00045897	0.00011528	0.00048264	0.00014113	0.00028349	0.00002117	0.00000387	0.00007528	0.00036854	0.00010586	0.00019054	0.00004234	0.00000213	0.01168628	0.00127606
RB_GUP_EPIS TOTAL	1.00000000	0.52022188	0.02706116	0.08154759	0.00175667	0.00022347	0.08653587	0.01545200	0.00388097	0.00008768	0.00299521	0.03803206	0.03247746	0.00669725	0.14721246	0.02126902	0.00047134	0.01260249	0.00147542
RB_GUP PRODUCTION	0.55115145	0.25901240	0.01134596	0.04273413	0.00076529	0.00008012	0.04627695	0.00900967	0.00266564	0.00005262	0.00161714	0.02240456	0.02374066	0.00521524	0.10898325	0.01678459	0.00025153	0.00017232	0.00003937
RB_GUP BULKTRAN	0.14426732	0.06779811	0.00296988	0.01118592	0.00020032	0.00002097	0.01211328	0.00235834	0.00069775	0.00001377	0.00042330	0.00586453	0.00621427	0.00136512	0.02852705	0.00439347	0.00006584	0.00004511	0.00001030
RB_GUP SUBTRAN	0.03713710	0.01692893	0.00072221	0.00272767	0.00004923	0.00000694	0.00300530	0.00058598	0.00022842	-	0.00010152	0.00145314	0.00209627	-	0.00921476	-	0.00001673	-	-
RB_GUP DISTPRI	0.15237895	0.10267206	0.00434685	0.01570360	0.00028128	-	0.01713909	0.00333778	-	-	0.00062205	0.00817819	-	-	-	-	0.00009804	-	-
RB_GUP DISTSEC	0.07475165	0.05550135	0.00303403	0.00769636	-	-	0.00741976	-	-	-	0.00022338	-	-	-	-	-	0.00003638	0.00069215	0.00014825
RB_GUP ENERGY	0.00112097	0.00039833	0.00002513	0.00008872	0.00000159	0.00000017	0.00009886	0.00001910	0.00000568	0.00000011	0.00000395	0.00005634	0.00005771	0.00001103	0.00029686	0.00004862	0.00000068	0.00000664	0.00000144
RB_GUP CUSTOMER	0.03919256	0.01791070	0.00461710	0.00141118	0.00045897	0.00011528	0.00048264	0.00014113	0.00028349	0.00002117	0.00000387	0.00007528	0.00036854	0.00010586	0.00019054	0.00004234	0.00000213	0.01168628	0.00127606
RB_GUP TOTAL	1.00000000	0.52022188	0.02706116	0.08154759	0.00175667	0.00022347	0.08653587	0.01545200	0.00388097	0.00008768	0.00299521	0.03803206	0.03247746	0.00669725	0.14721246	0.02126902	0.00047134	0.01260249	0.00147542
REV_OTHER PRODUCTION	0.12722787	0.09316980	0.00632686	0.01493540	0.00017664	0.00005592	0.00535807	0.00081634	0.00034833	0.00002379	0.00025395	0.00127407	0.00241475	0.00075025	0.00125827	-	-	0.00006543	-
REV_OTHER BULKTRAN	(0.03362678)	(0.02022324)	(0.00007671)	(0.00082270)	(0.00003312)	(0.00000177)	(0.00222718)	(0.00052604)	(0.00010568)	0.00000321	(0.00007791)	(0.00121259)	(0.00109811)	(0.00035484)	(0.00593481)	(0.00091218)	(0.00001367)	(0.00000730)	(0.00000214)
REV_OTHER SUBTRAN	(0.00861952)	(0.00505903)	(0.00001837)	(0.00020014)	(0.00000814)	(0.00000058)	(0.00055331)	(0.00013092)	(0.00003463)	(0.00000000)	(0.00001871)	(0.00030095)	(0.00037091)	(0.00000000)	(0.00192033)	-	(0.00000348)	(0.00000000)	-
REV_OTHER DISTPRI	0.43912859	0.30140192	0.01442260	0.04709433	0.00079146	(0.00000000)	0.04456725	0.00848538	(0.00000000)	(0.00000000)	0.00165807	0.02047073	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00023684	(0.00000000)	-
REV_OTHER DISTSEC	0.29451295	0.21916568	0.01309927	0.03102481	(0.00000000)	(0.00000000)	0.02721080	(0.00000000)	(0.00000000)	(0.00000000)	0.00083196	(0.00000000)	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00012742	0.00253387	0.00051915
REV_OTHER ENERGY	0.13687416	0.09181215	0.00699994	0.01580760	0.00022800	0.00007198	0.00689544	0.00115900	0.00043702	0.00002998	0.00037201	0.00237018	0.00359388	0.00109336	0.00506672	0.00050914	0.00000714	0.00040550	0.00001513
REV_OTHER CUSTOMER	0.04450272	0.02427736	0.00725649	0.00172637	0.00042790	0.00018801	0.00036732	0.00009886	0.00022518	0.00003328	0.00000318	0.00005027	0.00027276	0.00007924	0.00011600	0.00002516	0.00000123	0.00860313	0.00075098
REV_OTHER TOTAL	1.00000000	0.70454464	0.04801008	0.10956566	0.00158274	0.00031356	0.08161840	0.00990262	0.00087022	0.00009026	0.00302255	0.02265171	0.00481237	0.00156801	(0.00141414)	(0.00037788)	0.00035547	0.01160062	0.00128312
REV_SALES PRODUCTION	0.36609198	0.15042720	0.00976220	0.03613338	0.00052211	0.00005350	0.03629803	0.00721071	0.00191249	0.00003547	0.00116007	0.01565425	0.01807723	0.00335999	0.07282073	0.01147387	0.00020935	0.00081077	0.00017063
REV_SALES BULKTRAN	(0.00210248)	(0.00927060)	0.00073988	0.00331444	0.00002259	0.00000219	0.00179443	(0.00029944)	0.00020381	0.00000916	0.00004196	0.00005743	0.00136043	(0.00030039)	(0.00066193)	0.00085018	0.00001678	0.00001223	0.00000438
REV_SALES SUBTRAN	(0.00060498)	(0.00231983)	0.00018067	0.00081142	0.00000559	0.00000073	0.00044720	(0.00007446)	0.00006697	(0.00000000)	0.00001011	0.00001452	0.00046079	(0.00000000)	(0.00021297)	-	0.00000428	(0.00000000)	-
REV_SALES DISTPRI	0.13863181	0.08051775	0.00537522	0.02024555	0.00029865	(0.00000000)	0.01974134	0.00347680	(0.00000000)	(0.00000000)	0.00065401	0.00819980	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00012271	(0.00000000)	-
REV_SALES DISTSEC	0.05853803	0.03740801	0.00339080	0.00900066	(0.00000000)	(0.00000000)	0.00765244	(0.00000000)	(0.00000000)	(0.00000000)	0.00020907	(0.00000000)	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00004116	0.00065009	0.00018579
REV_SALES ENERGY	0.39617879	0.13217692	0.00923202	0.03288171	0.00056346	0.00005945	0.03653897	0.00788912	0.00196349	0.00004346	0.00139094	0.02039982	0.02117020	0.00411327	0.10809418	0.01690479	0.00025260	0.00198540	0.00051897
REV_SALES CUSTOMER	0.04326685	0.02159108	0.00630331	0.00202318	0.00041457	0.00010121	0.00052103	0.00012645	0.00029519	0.00003122	0.00000382	0.00006581	0.00038102	0.00006872	0.00015317	0.00004049	0.00000294	0.00948553	0.00165809
REV_SALES TOTAL	1.00000000	0.41053053	0.03498410	0.10441034	0.00182696	0.00021708	0.10299344	0.01832918	0.00444196	0.00011931	0.00346998	0.04439163	0.04144967	0.00724158	0.18019319	0.02926934	0.00064982	0.01294401	0.00253786
REV PRODUCTION	0.36200668	0.14944792	0.00970344	0.03577083	0.00051620	0.00005354	0.03576887	0.00710134	0.00188574	0.00003527	0.00114458	0.01540831	0.01780935	0.00331535	0.07159679	0.01127764	0.00020577	0.00079802	0.00016771
REV BULKTRAN	(0.00264164)	(0.00945792)	0.00072592	0.00324368	0.00002164	0.00000212	0.00172564	(0.00030332)	0.00019852	0.00000905	0.00003991	0.00003571	0.00131838	(0.00030133)	(0.00075211)	0.00082004	0.00001625	0.00001189	0.00000427
REV SUBTRAN	(0.00074205)	(0.00236668)	0.00017726	0.00079412	0.00000535	0.00000071	0.00043009	(0.00007542)	0.00006523	(0.00000000)	0.00000962	0.00000912	0.00044656	(0.00000000)	(0.00024217)	-	0.00000415	(0.00000000)	-
REV DISTPRI	0.14377122	0.08429554	0.00552995	0.02070475	0.00030707	(0.00000000)	0.02016594	0.00356246	(0.00000000)	(0.00000000)	0.00067118	0.00840967	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00012466	(0.00000000)	-
REV DISTSEC	0.06257392	0.04051662	0.00355685	0.00937734	(0.00000000)	(0.00000000)	0.00798694	(0.00000000)	(0.00000000)	(0.00000000)	0.00021972	(0.00000000)	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00004264	0.00068231	0.00019149
REV ENERGY	0.39174389	0.13148656	0.00919385	0.03258969	0.00055773	0.00005967	0.03603198	0.00777402	0.00193738	0.00004322	0.00137351	0.02009146	0.02086959	0.00406162	0.10633210	0.01662438	0.00024840	0.00195838	0.00051036
REV CUSTOMER	0.04328799	0.02163702	0.00631961	0.00201811	0.00041480	0.00010270	0.00051840	0.00012598	0.00029399	0.00003126	0.00000381	0.00006555	0.00037917	0.00006890	0.00015254	0.00004023	0.00000291	0.00947043	0.00164258
REV TOTAL	1.00000000	0.41555907	0.03520688	0.10449852	0.00182279	0.00021873	0.10262786	0.01818506	0.00438087	0.00011881	0.00346233	0.04401981	0.04082306	0.00714455	0.17708715	0.02876228	0.00064478	0.01292104	0.00251641
REVSALES PRODUCTION	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
REVSALES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
REVSALES_FXNL PRODUCTION	0.34965613	0.14720070	0.00874963	0.03331328	0.00049625	0.00004961	0.03348768	0.00557140	0.00199613	0.00003635	0.00112766	0.01479346	0.01743717	0.00293119	0.06962609	0.01210964	0.00019440	0.00044411	0.00009137
REVSALES_FXNL BULKTRAN	(0.00229353)	(0.00971162)	0.00074665	0.00334514	0.00002380	0.00000229	0.00179868	(0.00024843)	0.00022456	0.00000928	0.00004429	0.00005818	0.00138722	(0.00027900)	(0.00066340)	0.00093318	0.00001700	0.00001405	0.00000461
REVSALES_FXNL SUBTRAN	(0.00067586)	(0.00243019)	0.00018232	0.00081893	0.00000589	0.00000076	0.00044826	(0.00006177)	0.00007379	(0.00000000)	0.00001067	0.00001471	0.00046986	(0.00000000)	(0.00021344)	-	0.00000434	(0.00000000)	-
REVSALES_FXNL DISTPRI	0.14231549	0.08434819	0.00542437	0.02043306	0.00031467	(0.00000000)	0.01978814	0.00288446	(0.00000000)	(0.00000000)	0.00069026	0.00830801	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00012433	(0.00000000)	-
REVSALES_FXNL DISTSEC	0.06056854	0.03918761	0.00342181	0.00908402	(0.00000000)	(0.00000000)	0.00767058	(0.00000000)	(0.00000000)	(0.00000000)	0.00022066	(0.00000000)	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00004171	0.00074672	0.00019543
REVSALES_FXNL ENERGY	0.40451767	0.13846493	0.00931645	0.03318624	0.00059369	0.00006228	0.03662560	0.00654506	0.00216336	0.00004403	0.00146804	0.02066904	0.02158712	0.00382036	0.10833396	0.01855517	0.00025593	0.00228051	0.00054590
REVSALES_FXNL CUSTOMER	0.04591156	0.02261822	0.00636095	0.00204192	0.00043681	0.00010603	0.00052226	0.00010491	0.00032524	0.00003164	0.00000403	0.00006668	0.00038853	0.00006382	0.00015351	0.00004444	0.00000298	0.01089545	0.00174412
REVSALES_FXNL TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
REVYEC PRODUCTION	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414
REVYEC BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC TOTAL	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414
REVYEC_FXNL PRODUCTION	(0.54270748)	1.48490508	(0.04864797)	(0.17988134)	0.02639156	0.00225622	(0.50098652)	(1.70771860)	0.22235726	-	0.06251300	0.00002952	0.15393703	(0.36902159)	(1.05646224)	1.29042117	(0.00000152)	0.07254583	0.00465564
REVYEC_FXNL BULKTRAN	0.11730396	(0.09796721)	(0.00415138)	(0.01806270)	0.00126577	0.00010413	(0.02690883)	0.07614610	0.02501477	-	0.00245509	0.00000012	0.01224652	0.03512504	0.01006597	0.09944150	(0.00000013)	0.00229436	0.00023485
REVYEC_FXNL SUBTRAN	(0.00117675)	(0.02451482)	(0.00101370)	(0.00442199)	0.00031322	0.00003473	(0.00670618)	0.01893418	0.00821965	-	0.00059152	0.00000003	0.00414799	0.00000000	0.00323865	-	(0.00000003)	(0.00000000)	-
REVYEC_FXNL DISTPRI	(0.41477046)	0.85087274	(0.03015953)	(0.11033215)	0.01673451	(0.00000000)	(0.29603696)	(0.88412980)	(0.00000000)	-	0.03826512	0.00001658	(0.00000000)	0.00000000	0.00000000	-	(0.00000097)	(0.00000000)	-
REVYEC_FXNL DISTSEC	0.35664757	0.39530985	(0.01902529)	(0.04905089)	(0.00000000)	(0.00000000)	(0.11475429)	0.00000000	(0.00000000)	-	0.01223240	(0.00000000)	(0.00000000)	0.00000000	0.00000000	-	(0.00000033)	0.12197839	0.00995773
REVYEC_FXNL ENERGY	(0.58806379)	1.39678195	(0.05179951)	(0.17919539)	0.03157342	0.00283263	(0.54793069)	(2.00615846)	0.24098515	-	0.08138239	0.00004125	0.19057319	(0.48096367)	(1.64379101)	1.97726719	(0.00000200)	0.37252387	0.02781590
REVYEC_FXNL CUSTOMER	2.07276695	0.22816407	(0.03536692)	(0.01102574)	0.02323029	0.00482232	(0.00781323)	(0.03215587)	0.03622971	-	0.00022349	0.00000013	0.00342996	(0.00803501)	(0.00232934)	0.00473608	(0.00000002)	1.77978700	0.08887003
REVYEC_FXNL TOTAL	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414
REVYEC_EXP_OM PRODUCTION	(0.70072779)	2.10952880	(0.07086782)	(0.25638944)	0.04248480	0.00401464	(0.70045554)	(2.22309022)	0.29710226	-	0.08636593	0.00003942	0.19279881	(0.45302114)	(1.32480698)	1.53863589	(0.00000206)	0.05400380	0.00293107
REVYEC_EXP_OM BULKTRAN	0.16553377	(0.49834092)	0.01672643	0.06051499	(0.01003127)	(0.00094805)	0.16535716	0.52501357	(0.07012723)	-	(0.02038725)	(0.00000931)	(0.04550432)	0.10698337	0.31272129	(0.36299485)	0.00000049	(0.01274918)	(0.00069114)
REVYEC_EXP_OM SUBTRAN	0.12111271	(0.12464816)	0.00407453	0.01478193	(0.00246929)	(0.00031414)	0.04109570	0.13067652	(0.02299647)	-	(0.00489799)	(0.00000231)	(0.01537652)	-	0.10118880	-	0.00000012	-	-
REVYEC_EXP_OM DISTPRI	(0.24250515)	0.63494025	(0.02061846)	(0.07154791)	0.01185766	-	(0.19699910)	(0.62537596)	-	-	0.02522805	0.00001093	-	-	-	-	(0.00000061)	-	-
REVYEC_EXP_OM DISTSEC	0.31146337	0.27365093	(0.01147559)	(0.02796121)	-	-	(0.06800272)	-	-	-	0.00722384	-	-	-	-	-	(0.00000018)	0.13134266	0.00668565
REVYEC_EXP_OM ENERGY	(0.08182657)	1.59825916	(0.07730544)	(0.26212911)	0.04356956	0.00418903	(0.73691669)	(2.32099969)	0.31187658	-	0.10398023	0.00004882	0.23080964	(0.47195707)	(1.77714642)	2.19415532	(0.00000275)	1.02479722	0.05294502
REVYEC_EXP_OM CUSTOMER	1.42694966	0.24016160	(0.03069793)	(0.00923944)	0.01409730	0.00310855	(0.00521551)	(0.02130668)	0.01695140	-	0.00015020	0.00000008	0.00160708	(0.00490039)	(0.00123466)	0.00206958	(0.00000002)	1.15173495	0.06966355
REVYEC_EXP_OM TOTAL	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9	LGS-TRA 10	QP-SEC 11	QP-PRI 12	QP-SUB 13	QP-TRA 14	CIP-TOD-SUB 15	CIP-TOD-TRA 16	MW 17	OL 18	SL 19
TDOMX PRODUCTION	0.16947264	0.07964329	0.00348875	0.01314025	0.00023532	0.00002464	0.01422962	0.00277037	0.00081965	0.00001618	0.00049725	0.00688914	0.00729998	0.00160363	0.03351108	0.00516107	0.00007734	0.00005299	0.00001211
TDOMX BULKTRAN	0.11828798	0.05558917	0.00243507	0.00917159	0.00016425	0.00001719	0.00993195	0.00193365	0.00057210	0.00001129	0.00034707	0.00480846	0.00509522	0.00111929	0.02338996	0.00360231	0.00005398	0.00003698	0.00000845
TDOMX SUBTRAN	0.03050193	0.01390429	0.00059318	0.00224033	0.00004043	0.00000570	0.00246835	0.00048129	0.00018760	-	0.00008338	0.00119351	0.00172174	-	0.00756839	-	0.00001374	-	-
TDOMX DISTPRI	0.46233747	0.31152033	0.01318890	0.04764674	0.00085344	-	0.05200222	0.01012727	-	-	0.00188738	0.02481370	-	-	-	-	0.00029748	-	-
TDOMX DISTSEC	0.18078364	0.13422762	0.00733766	0.01861331	-	-	0.01794436	-	-	-	0.00054024	-	-	-	-	-	0.00008800	0.00167393	0.00035853
TDOMX ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDOMX CUSTOMER	0.03861634	0.01471827	0.00585466	0.00179694	0.00096221	0.00024157	0.00088934	0.00029562	0.00059413	0.00004438	0.00000713	0.00015767	0.00077236	0.00022189	0.00039941	0.00008876	0.00000270	0.00786120	0.00370810
TDOMX TOTAL	1.00000000	0.60960297	0.03289822	0.09260916	0.00225564	0.00028910	0.09746584	0.01560820	0.00217348	0.00007185	0.00336245	0.03786248	0.01488929	0.00294481	0.06486883	0.00885213	0.00053325	0.00962511	0.00408718
TDPLANT PRODUCTION	0.00898476	0.00422237	0.00018496	0.00069664	0.00001248	0.00000131	0.00075440	0.00014687	0.00004345	0.00000086	0.00002636	0.00036523	0.00038702	0.00008502	0.00177662	0.00027362	0.00000410	0.00000281	0.00000064
TDPLANT BULKTRAN	0.32595470	0.15318169	0.00671008	0.02527325	0.00045259	0.00004738	0.02736850	0.00532838	0.00157648	0.00003112	0.00095639	0.01325021	0.01404039	0.00308433	0.06445343	0.00992652	0.00014876	0.00010191	0.00002328
TDPLANT SUBTRAN	0.08390644	0.03824872	0.00163174	0.00616282	0.00011122	0.00001567	0.00679008	0.00132395	0.00051607	-	0.00022937	0.00328318	0.00473625	-	0.02081956	-	0.00003780	-	-
TDPLANT DISTPRI	0.33287810	0.22429135	0.00949587	0.03430515	0.00061447	-	0.03744105	0.00729153	-	-	0.00135889	0.01786560	-	-	-	-	0.00021418	-	-
TDPLANT DISTSEC	0.16452236	0.12215399	0.00667764	0.01693907	-	-	0.01633028	-	-	-	0.00049164	-	-	-	-	-	0.00008008	0.00152337	0.00032628
TDPLANT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDPLANT CUSTOMER	0.08375364	0.03702130	0.00987435	0.00301375	0.00101247	0.00025452	0.00105460	0.00031030	0.00062596	0.00004676	0.00000844	0.00016550	0.00081375	0.00023378	0.00042081	0.00009351	0.00000456	0.02600824	0.00279103
TDPLANT TOTAL	1.00000000	0.57911942	0.03457465	0.08639069	0.00220323	0.00031888	0.08973891	0.01440104	0.00276196	0.00007874	0.00307110	0.03492972	0.01997741	0.00340313	0.08747042	0.01029365	0.00048948	0.02763633	0.00314124
TOTMXEXP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP DISTPRI	0.71346355	0.48072763	0.02035267	0.07352684	0.00131700	-	0.08024807	0.01562806	-	-	0.00291254	0.03829166	-	-	-	-	0.00045906	-	-
TOTMXEXP DISTSEC	0.27735383	0.20592871	0.01125726	0.02855609	-	-	0.02752980	-	-	-	0.00082882	-	-	-	-	-	0.00013500	0.00256811	0.00055005
TOTMXEXP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP CUSTOMER	0.00918263	0.00096886	0.00056508	0.00017407	0.00011528	0.00002898	0.00010233	0.00003533	0.00007127	0.00000532	0.00000082	0.00001884	0.00009265	0.00002662	0.00004791	0.00001065	0.00000026	0.00541244	0.00150590
TOTMXEXP TOTAL	1.00000000	0.68762520	0.03217501	0.10225700	0.00143228	0.00002898	0.10788020	0.01566339	0.00007127	0.00000532	0.00374218	0.03831051	0.00009265	0.00002662	0.00004791	0.00001065	0.00059432	0.00798055	0.00205595
TOTOHLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES DISTPRI	0.71460136	0.48149429	0.02038513	0.07364410	0.00131910	-	0.08037605	0.01565298	-	-	0.00291719	0.03835273	-	-	-	-	0.00045979	-	-
TOTOHLINES DISTSEC	0.28539864	0.21190180	0.01158378	0.02938437	-	-	0.02832831	-	-	-	0.00085286	-	-	-	-	-	0.00013892	0.00264260	0.00056600
TOTOHLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES TOTAL	1.00000000	0.69339608	0.03196891	0.10302848	0.00131910	-	0.10870436	0.01565298	-	-	0.00377004	0.03835273	-	-	-	-	0.00059871	0.00264260	0.00056600
TOTOX234 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 CUSTOMER	1.00000000	0.85558580	0.10631437	0.03409641	0.00040902	0.00004864	0.00388589	0.00039557	0.00010559	0.00000512	0.00003335	0.00022185	0.00014419	0.00002762	0.00004986	0.00001112	0.00004905	(0.00160304)	0.00021957
TOTOX234 TOTAL	1.00000000	0.85558580	0.10631437	0.03409641	0.00040902	0.00004864	0.00388589	0.00039557	0.00010559	0.00000512	0.00003335	0.00022185	0.00014419	0.00002762	0.00004986	0.00001112	0.00004905	(0.00160304)	0.00021957
TOTOXEXP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP DISTPRI	0.53609267	0.36121615	0.01529289	0.05524767	0.00098959	-	0.06029797	0.01174284	-	-	0.00218847	0.02877215	-	-	-	-	0.00034494	-	-
TOTOXEXP DISTSEC	0.21616776	0.16049949	0.00877383	0.02225643	-	-	0.02145654	-	-	-	0.00064597	-	-	-	-	-	0.00010522	0.00200157	0.00042870
TOTOXEXP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP CUSTOMER	0.24773957	0.10461445	0.04089024	0.01254772	0.00663006	0.00166440	0.00614495	0.00203733	0.00409342	0.00030576	0.00004923	0.00108657	0.00532145	0.00152880	0.00275184	0.00061152	0.00001888	0.03616703	0.02127591
TOTOXEXP TOTAL	1.00000000	0.62633010	0.06495696	0.09005182	0.00761965	0.00166440	0.08789946	0.01378016	0.00409342	0.00030576	0.00288367	0.02985873	0.00532145	0.00152880	0.00275184	0.00061152	0.00046904	0.03816859	0.02170462
TOTUGLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES DISTPRI	0.72760000	0.49025269	0.02075593	0.07498369	0.00134310	-	0.08183810	0.01593771	-	-	0.00297025	0.03905037	-	-	-	-	0.00046816	-	-
TOTUGLINES DISTSEC	0.27240000	0.20225061	0.01105619	0.02804605	-	-	0.02703808	-	-	-	0.00081401	-	-	-	-	-	0.00013259	0.00252224	0.00054022
TOTUGLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES TOTAL	1.00000000	0.69250331	0.03181212	0.10302974	0.00134310	-	0.10887618	0.01593771	-	-	0.00378426	0.03905037	-	-	-	-	0.00060075	0.00252224	0.00054022
TRANS_TOTAL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL BULKTRAN	0.79500000	0.37360849	0.01636580	0.06164119	0.00110387	0.00011556	0.06675148	0.01299586	0.00384501	0.00007590	0.00233262	0.03231712	0.03424436	0.00752264	0.15720123	0.02421068	0.00036282	0.00024856	0.00005679
TRANS_TOTAL SUBTRAN	0.20500000	0.09344917	0.00398667	0.01505699	0.00027173	0.00003829	0.01658950	0.00323468	0.00126087	-	0.00056041	0.00802145	0.01157160	-	0.05086628	-	0.00009235	-	-
TRANS_TOTAL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL TOTAL	1.00000000	0.46705766	0.02035248	0.07669818	0.00137560	0.00015386	0.08334098	0.01623054	0.00510588	0.00007590	0.00289303	0.04033857	0.04581596	0.00752264	0.20806752	0.02421068	0.00045517	0.00024856	0.00005679
WEATHER_FXNL PRODUCTION	0.35074689	0.35074689	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL BULKTRAN	(0.02314067)	(0.02314067)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL SUBTRAN	(0.00579060)	(0.00579060)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL DISTPRI	0.20098320	0.20098320	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL DISTSEC	0.09337546	0.09337546	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL ENERGY	0.32993148	0.32993148	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL CUSTOMER	0.05389424	0.05389424	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL TOTAL	1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
INPUTS FROM WORKPAPERS																				
CPG		1,135,297	533,531	23,371	88,027	1,576	165	95,324	18,559	5,491	108	3,331	46,150	48,903	10,743	224,491	34,574	518	355	81
PROD_DEMAND	PRODUCTION	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
PROD_DEMAND	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	TOTAL	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
ENER		6,936,779,389	2,464,926,510	155,527,434	549,023,139	9,860,484	1,050,234	611,738,140	118,170,497	35,161,710	691,432	24,464,275	348,666,057	357,149,505	68,257,086	1,837,008,639	300,840,877	4,216,330	41,086,927	8,940,115
PROD_ENERGY	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	ENERGY	1.00000000	0.35534163	0.02242070	0.07914669	0.00142148	0.00015140	0.08818763	0.01703535	0.00506888	0.00009968	0.00352675	0.05026339	0.05148636	0.00983988	0.26482155	0.04336896	0.00060782	0.00592306	0.00128880
PROD_ENERGY	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	TOTAL	1.00000000	0.35534163	0.02242070	0.07914669	0.00142148	0.00015140	0.08818763	0.01703535	0.00506888	0.00009968	0.00352675	0.05026339	0.05148636	0.00983988	0.26482155	0.04336896	0.00060782	0.00592306	0.00128880
CPT		1,135,297	533,531	23,371	88,027	1,576	165	95,324	18,559	5,491	108	3,331	46,150	48,903	10,743	224,491	34,574	518	355	81
BULK_TRANS	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	BULKTRAN	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
BULK_TRANS	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	TOTAL	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
CPST		875,462	399,079	17,025	64,302	1,160	164	70,846	13,814	5,385	0	2,393	34,256	49,417	0	217,227	0	394	0	0
SUB_TRANS	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	SUBTRAN	1.00000000	0.45584960	0.01944719	0.07344872	0.00132550	0.00018679	0.08092440	0.01577893	0.00615059	-	0.00273369	0.03912901	0.05644684	-	0.24812822	-	0.00045051	-	-
SUB_TRANS	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	TOTAL	1.00000000	0.45584960	0.01944719	0.07344872	0.00132550	0.00018679	0.08092440	0.01577893	0.00615059	-	0.00273369	0.03912901	0.05644684	-	0.24812822	-	0.00045051	-	-
ENER_SUB		5,351,552,502	1,809,522,763	114,224,064	403,247,193	7,241,451	1,019,967	449,377,547	86,802,959	34,152,839	0	17,973,192	256,179,808	346,976,932	0	1,784,967,113	0	3,097,895	30,197,883	6,570,896
SUB_ENERGY	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_ENERGY	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_ENERGY	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_ENERGY	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_ENERGY	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_ENERGY	ENERGY	1.00000000	0.33813043	0.02134410	0.07535144	0.00135315	0.00019059	0.08397144	0.01622015	0.00638186	-	0.00335850	0.04787018	0.06483669	-	0.33354192	-	0.00057888	0.00564283	0.00122785
SUB_ENERGY	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_ENERGY	TOTAL	1.00000000	0.33813043	0.02134410	0.07535144	0.00135315	0.00019059	0.08397144	0.01622015	0.00638186	-	0.00335850	0.04787018	0.06483669	-	0.33354192	-	0.00057888	0.00564283	0.00122785
CPD		792,245	533,810	22,600	81,646	1,462	0	89,109	17,354	0	0	3,234	42,520	0	0	0	0	510	0	0
DIST_CPD	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	DISTPRI	1.00000000	0.67379424	0.02852657	0.10305620	0.00184593	-	0.11247677	0.02190449	-	-	0.00408226	0.05367011	-	-	-	-	0.00064343	-	-
DIST_CPD	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	TOTAL	1.00000000	0.67379424	0.02852657	0.10305620	0.00184593	-	0.11247677	0.02190449	-	-	0.00408226	0.05367011	-	-	-	-	0.00064343	-	-
SECDEM		1,518,254	1,127,268	61,623	156,318	0	0	150,700	0	0	0	4,537	0	0	0	0	0	739	14,058	3,011
DISTSEC	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	DISTSEC	1.00000000	0.74247656	0.04058807	0.10295906	-	-	0.09925875	-	-	-	0.00298830	-	-	-	-	-	0.00048674	0.00925932	0.00198320
DISTSEC	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	TOTAL	1.00000000	0.74247656	0.04058807	0.10295906	-	-	0.09925875	-	-	-	0.00298830	-	-	-	-	-	0.00048674	0.00925932	0.00198320
TOTCUST		217,981	138,300	23,823	7,203	84	10	756	75	20	1	6	40	26	5	9	2	11	47,554	56
CUST_TOTAL	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	CUSTOMER	1.00000000	0.63445897	0.10928934	0.03304416	0.00038535	0.00004588	0.00346819	0.00034407	0.00009175	0.00000459	0.00002753	0.00018350	0.00011928	0.00002294	0.00004129	0.00000918	0.00005046	0.21815663	0.00025690
CUST_TOTAL	TOTAL	1.00000000	0.63445897	0.10928934	0.03304416	0.00038535	0.00004588	0.00346819	0.00034407	0.00009175	0.00000459	0.00002753	0.00018350	0.00011928	0.00002294	0.00004129	0.00000918	0.00005046	0.21815663	0.00025690
PRICUST		217,908	138,300	23,823	7,203	84	0	756	75	0	0	6	40	0	0	0	0	11	47,554	56
DIST_PCUST	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	CUSTOMER	1.00000000	0.63467151	0.10932595	0.03305523	0.00038548	-	0.00346935	0.00034418	-	-	0.00002753	0.00018356	-	-	-	-	0.00005048	0.21822971	0.00025699
DIST_PCUST	TOTAL	1.00000000	0.63467151	0.10932595	0.03305523	0.00038548	-	0.00346935	0.00034418	-	-	0.00002753	0.00018356	-	-	-	-	0.00005048	0.21822971	0.00025699

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
SECCUST		217,709	138,300	23,823	7,203	0	0	756	0	0		6	0	0		0	0	11	47,554	56
DIST_SERV	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	CUSTOMER	1.00000000	0.63525164	0.10942589	0.03308545	-	-	0.00347253	-	-	-	0.00002756	-	-	-	-	-	0.00005053	0.21842919	0.00025722
DIST_SERV	TOTAL	1.00000000	0.63525164	0.10942589	0.03308545	-	-	0.00347253	-	-	-	0.00002756	-	-	-	-	-	0.00005053	0.21842919	0.00025722
METER		34,588,386	14,799,965	8,632,025	2,658,967	1,760,972	442,678	1,563,169	539,707	1,088,722	81,323	12,529	287,844	1,415,338	406,613	731,903	162,645	3,986	0	0
DIST_METERS	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	CUSTOMER	1.00000000	0.42788828	0.24956426	0.07687456	0.05091223	0.01279846	0.04519346	0.01560371	0.03147652	0.00235116	0.00036223	0.00832198	0.04091946	0.01175577	0.02116037	0.00470230	0.00011524	-	-
DIST_METERS	TOTAL	1.00000000	0.42788828	0.24956426	0.07687456	0.05091223	0.01279846	0.04519346	0.01560371	0.03147652	0.00235116	0.00036223	0.00832198	0.04091946	0.01175577	0.02116037	0.00470230	0.00011524	-	-
DIR371		1	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	1	0
DIST_OL	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	CUSTOMER	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIST_OL	TOTAL	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIR373		1	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	1
DIST_SL	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	CUSTOMER	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_SL	TOTAL	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIR902		350,616	276,600	47,646	21,609	294	35	3,402	375	100	5	36	240	156	30	54	12	22	0	0
CUST_902	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	CUSTOMER	1.00000000	0.78889726	0.13589226	0.06163153	0.00083852	0.00009982	0.00970292	0.00106955	0.00028521	0.00001426	0.00010268	0.00068451	0.00044493	0.00008556	0.00015401	0.00003423	0.00006275	-	-
CUST_902	TOTAL	1.00000000	0.78889726	0.13589226	0.06163153	0.00083852	0.00009982	0.00970292	0.00106955	0.00028521	0.00001426	0.00010268	0.00068451	0.00044493	0.00008556	0.00015401	0.00003423	0.00006275	-	-
DIR903		5,289,649	4,553,062	546,200	165,146	1,926	229	17,333	1,719	459	22	138	917	596	114	206	46	252	0	1,284
CUST_903	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	CUSTOMER	1.00000000	0.86074937	0.10325827	0.03122060	0.00036411	0.00004329	0.00327678	0.00032497	0.00008677	0.00000416	0.00002609	0.00017336	0.00011267	0.00002155	0.00003894	0.00000870	0.00004764	-	0.00024274
CUST_903	TOTAL	1.00000000	0.86074937	0.10325827	0.03122060	0.00036411	0.00004329	0.00327678	0.00032497	0.00008677	0.00000416	0.00002609	0.00017336	0.00011267	0.00002155	0.00003894	0.00000870	0.00004764	-	0.00024274
CUST451		439,928	393,866	31,803	11,011	161	-	189	33	-	-	-	46	7	-	-	7	-	2,805	-
CUST_451	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	CUSTOMER	1.00000000	0.89529643	0.07229171	0.02502863	0.00036697	-	0.00042959	0.00007476	-	-	-	0.00010418	0.00001591	-	-	0.00001591	-	0.00637590	-
CUST_451	TOTAL	1.00000000	0.89529643	0.07229171	0.02502863	0.00036697	-	0.00042959	0.00007476	-	-	-	0.00010418	0.00001591	-	-	0.00001591	-	0.00637590	-
CUSTDEP		24,459,717	17,841,958	1,074,084	2,114,234	533,240	89,908	908,545	371,216	150,766	33,502	-	432,772	469,665	320,187	-	-	-	119,640	-
CUST_DEP	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	CUSTOMER	1.00000000	0.72944254	0.04391236	0.08643739	0.02180074	0.00367576	0.03714454	0.01517663	0.00616385	0.00136968	-	0.01769325	0.01920157	0.01309038	-	-	-	0.00489131	-
CUST_DEP	TOTAL	1.00000000	0.72944254	0.04391236	0.08643739	0.02180074	0.00367576	0.03714454	0.01517663	0.00616385	0.00136968	-	0.01769325	0.01920157	0.01309038	-	-	-	0.00489131	-
RYEC		(399,402)	(1,690,889)	75,952	220,458	(39,744)	(4,014)	599,557	1,811,321	(212,804)	-	(78,947)	(35)	(145,516)	328,666	1,074,103	(1,346,730)	2	(938,247)	(52,535)
REVYEC	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	CUSTOMER	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414
REVYEC	TOTAL	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
FORF DISCOUNTS			3,643,764	2,591,161	241,249	447,053	6,497	2,430	156,609	21,147	8,142	774	7,833	36,889	55,750	16,320	31,244	-	-	20,666	-
FORF_DISC	PRODUCTION		1.00000000	0.71112214	0.06620871	0.12269002	0.00178294	0.00066684	0.04297993	0.00580371	0.00223445	0.00021246	0.00214966	0.01012398	0.01530002	0.00447882	0.00857472	-	-	0.00567159	-
FORF_DISC	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	TOTAL		1.00000000	0.71112214	0.06620871	0.12269002	0.00178294	0.00066684	0.04297993	0.00580371	0.00223445	0.00021246	0.00214966	0.01012398	0.01530002	0.00447882	0.00857472	-	-	0.00567159	-
YEAR END CUST ADJ			(399,402)	(1,690,889)	75,952	220,458	(39,744)	(4,014)	599,557	1,811,321	(212,804)	-	(78,947)	(35)	(145,516)	328,666	1,074,103	(1,346,730)	2	(938,247)	(52,535)
REVYEC	PRODUCTION		1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414
REVYEC	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	TOTAL		1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414
FUELR			13,374,764	4,777,562	289,822	1,023,252	19,857	2,126	1,131,261	183,139	74,860	1,373	47,671	675,960	703,383	123,998	3,561,676	646,445	7,887	87,066	17,426
FUELREV	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	ENERGY		1.00000000	0.35720720	0.02166932	0.07650617	0.00148466	0.00015896	0.08458175	0.01369288	0.00559711	0.00010266	0.00356425	0.05053996	0.05259031	0.00927104	0.26629823	0.04833319	0.00058969	0.00650972	0.00130290
FUELREV	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	TOTAL		1.00000000	0.35720720	0.02166932	0.07650617	0.00148466	0.00015896	0.08458175	0.01369288	0.00559711	0.00010266	0.00356425	0.05053996	0.05259031	0.00927104	0.26629823	0.04833319	0.00058969	0.00650972	0.00130290
WEATHER			(5,929,131)	(5,929,131)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	ENERGY		1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	TOTAL		1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_GROSS_UP			10,014,069	4,082,297	449,721	1,287,479	21,055	2,529	1,190,166	203,960	41,508	(168)	37,744	433,913	402,343	84,049	1,379,302	181,775	7,199	174,693	34,504
ATR_ADJ	PRODUCTION		1.00000000	0.40765617	0.04490892	0.12856702	0.00210254	0.00025254	0.11884939	0.02036735	0.00414497	(0.00001678)	0.00376910	0.04333034	0.04017777	0.00839309	0.13773642	0.01815196	0.00071889	0.01744476	0.00344555
ATR_ADJ	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATR_ADJ	TOTAL		1.00000000	0.40765617	0.04490892	0.12856702	0.00210254	0.00025254	0.11884939	0.02036735	0.00414497	(0.00001678)	0.00376910	0.04333034	0.04017777	0.00839309	0.13773642	0.01815196	0.00071889	0.01744476	0.00344555

INTERNALLY DERIVED

Bulk Transmission Plant	$409,750,988.28
Subtransmission Plant	$105,804,409.72
Total Transmisison Plant	$515,555,398.00

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
BULK_TRANS	BULKTRAN	79.50%	1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
SUB_TRANS	SUBTRAN	20.50%	1.00000000	0.45584960	0.01944719	0.07344872	0.00132550	0.00018679	0.08092440	0.01577893	0.00615059	-	0.00273369	0.03912901	0.05644684	-	0.24812822	-	0.00045051	-	-
TRANS_TOTAL	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	BULKTRAN		0.79500000	0.37360849	0.01636580	0.06164119	0.00110387	0.00011556	0.06675148	0.01299586	0.00384501	0.00007590	0.00233262	0.03231712	0.03424436	0.00752264	0.15720123	0.02421068	0.00036282	0.00024856	0.00005679
TRANS_TOTAL	SUBTRAN		0.20500000	0.09344917	0.00398667	0.01505699	0.00027173	0.00003829	0.01658950	0.00323468	0.00126087	-	0.00056041	0.00802145	0.01157160	-	0.05086628	-	0.00009235	-	-
TRANS_TOTAL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	TOTAL		1.00000000	0.46705766	0.02035248	0.07669818	0.00137560	0.00015386	0.08334098	0.01623054	0.00510588	0.00007590	0.00289303	0.04033857	0.04581596	0.00752264	0.20806752	0.02421068	0.00045517	0.00024856	0.00005679
DIST_CPD	DISTPRI	56.15%	1.00000000	0.67379424	0.02852657	0.10305620	0.00184593	-	0.11247677	0.02190449	-	-	0.00408226	0.05367011	-	-	-	-	0.00064343	-	-
DISTSEC	DISTSEC	43.85%	1.00000000	0.74247656	0.04058807	0.10295906	-	-	0.09925875	-	-	-	0.00298830	-	-	-	-	-	0.00048674	0.00925932	0.00198320
DIST_POLES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	DISTPRI		0.56150000	0.37833547	0.01601767	0.05786606	0.00103649	-	0.06315570	0.01229937	-	-	0.00229219	0.03013576	-	-	-	-	0.00036128	-	-
DIST_POLES	DISTSEC		0.43850000	0.32557597	0.01779787	0.04514755	-	-	0.04352496	-	-	-	0.00131037	-	-	-	-	-	0.00021344	0.00406021	0.00086963
DIST_POLES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	TOTAL		1.00000000	0.70391144	0.03381554	0.10301360	0.00103649	-	0.10668067	0.01229937	-	-	0.00360256	0.03013576	-	-	-	-	0.00057472	0.00406021	0.00086963
DIST_CPD	DISTPRI	86.46%	1.00000000	0.67379424	0.02852657	0.10305620	0.00184593	-	0.11247677	0.02190449	-	-	0.00408226	0.05367011	-	-	-	-	0.00064343	-	-
DISTSEC	DISTSEC	13.54%	1.00000000	0.74247656	0.04058807	0.10295906	-	-	0.09925875	-	-	-	0.00298830	-	-	-	-	-	0.00048674	0.00925932	0.00198320
DIST_OHLINES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	DISTPRI		0.86460000	0.58256250	0.02466407	0.08910239	0.00159599	-	0.09724741	0.01893862	-	-	0.00352952	0.04640317	-	-	-	-	0.00055631	-	-
DIST_OHLINES	DISTSEC		0.13540000	0.10053133	0.00549562	0.01394066	-	-	0.01343964	-	-	-	0.00040462	-	-	-	-	-	0.00006591	0.00125371	0.00026853
DIST_OHLINES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	TOTAL		1.00000000	0.68309383	0.03015970	0.10304305	0.00159599	-	0.11068705	0.01893862	-	-	0.00393414	0.04640317	-	-	-	-	0.00062221	0.00125371	0.00026853

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION		Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
DIST_CPD	DISTPRI	72.76%	1.00000000	0.67379424	0.02852657	0.10305620	0.00184593	-	0.11247677	0.02190449	-	-	0.00408226	0.05367011	-	-	-	-	0.00064343	-	-
DISTSEC	DISTSEC	27.24%	1.00000000	0.74247656	0.04058807	0.10295906	-	-	0.09925875	-	-	-	0.00298830	-	-	-	-	-	0.00048674	0.00925932	0.00198320
DIST_UGLINES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	DISTPRI		0.72760000	0.49025269	0.02075593	0.07498369	0.00134310	-	0.08183810	0.01593771	-	-	0.00297025	0.03905037	-	-	-	-	0.00046816	-	-
DIST_UGLINES	DISTSEC		0.27240000	0.20225061	0.01105619	0.02804605	-	-	0.02703808	-	-	-	0.00081401	-	-	-	-	-	0.00013259	0.00252224	0.00054022
DIST_UGLINES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	TOTAL		1.00000000	0.69250331	0.03181212	0.10302974	0.00134310	-	0.10887618	0.01593771	-	-	0.00378426	0.03905037	-	-	-	-	0.00060075	0.00252224	0.00054022
DIST_CPD	DISTPRI	24.98%	1.00000000	0.67379424	0.02852657	0.10305620	0.00184593	-	0.11247677	0.02190449	-	-	0.00408226	0.05367011	-	-	-	-	0.00064343	-	-
DISTSEC	DISTSEC	75.02%	1.00000000	0.74247656	0.04058807	0.10295906	-	-	0.09925875	-	-	-	0.00298830	-	-	-	-	-	0.00048674	0.00925932	0.00198320
DIST_TRANSF	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	DISTPRI		0.24980000	0.16831380	0.00712594	0.02574344	0.00046111	-	0.02809670	0.00547174	-	-	0.00101975	0.01340679	-	-	-	-	0.00016073	-	-
DIST_TRANSF	DISTSEC		0.75020000	0.55700591	0.03044917	0.07723988	-	-	0.07446392	-	-	-	0.00224182	-	-	-	-	-	0.00036515	0.00694634	0.00148780
DIST_TRANSF	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	TOTAL		1.00000000	0.72531971	0.03757511	0.10298332	0.00046111	-	0.10256061	0.00547174	-	-	0.00326157	0.01340679	-	-	-	-	0.00052588	0.00694634	0.00148780
SALES OF ELECTRICITY	PRODUCTION		205,228,629	84,328,446	5,472,620	20,256,125	292,689	29,989	20,348,426	4,042,272	1,072,130	19,886	650,329	8,775,666	10,133,969	1,883,585	40,822,796	6,432,175	117,360	454,511	95,656
	BULKTRAN		(1,178,637)	(5,197,033)	414,774	1,858,052	12,663	1,225	1,005,943	(167,864)	114,257	5,133	23,523	32,193	762,647	(168,399)	(371,073)	476,606	9,404	6,855	2,456
	SUBTRAN		(339,147)	(1,300,479)	101,281	454,876	3,134	409	250,700	(41,740)	37,544	-	5,668	8,140	258,314	-	(119,390)	-	2,399	-	-
	DISTPRI		77,716,035	45,137,693	3,013,309	11,349,515	167,419	-	11,066,859	1,949,069	-	-	366,631	4,596,750	-	-	-	-	68,790	-	-
	DISTSEC		32,816,013	20,970,674	1,900,861	5,045,708	-	-	4,289,902	-	-	-	117,203	-	-	-	-	-	23,076	364,438	104,150
	ENERGY		222,095,087	74,097,467	5,175,409	18,433,256	315,873	33,329	20,483,496	4,422,587	1,100,720	24,361	779,752	11,435,998	11,867,867	2,305,872	60,596,851	9,476,710	141,604	1,113,000	290,933
	CUSTOMER		24,255,095	12,103,807	3,533,591	1,134,182	232,405	56,740	292,085	70,888	165,482	17,504	2,141	36,895	213,599	38,522	85,869	22,699	1,650	5,317,520	929,514
	TOTAL		560,593,075	230,140,574	19,611,844	58,531,716	1,024,183	121,692	57,737,410	10,275,210	2,490,133	66,884	1,945,247	24,885,642	23,236,397	4,059,580	101,015,053	16,408,190	364,284	7,256,325	1,422,710
REV_SALES	PRODUCTION		0.36609198	0.15042720	0.00976220	0.03613338	0.00052211	0.00005350	0.03629803	0.00721071	0.00191249	0.00003547	0.00116007	0.01565425	0.01807723	0.00335999	0.07282073	0.01147387	0.00020935	0.00081077	0.00017063
REV_SALES	BULKTRAN		(0.00210248)	(0.00927060)	0.00073988	0.00331444	0.00002259	0.00000219	0.00179443	(0.00029944)	0.00020381	0.00000916	0.00004196	0.00005743	0.00136043	(0.00030039)	(0.00066193)	0.00085018	0.00001678	0.00001223	0.00000438
REV_SALES	SUBTRAN		(0.00060498)	(0.00231983)	0.00018067	0.00081142	0.00000559	0.00000073	0.00044720	(0.00007446)	0.00006697	-	0.00001011	0.00001452	0.00046079	-	(0.00021297)	-	0.00000428	-	-
REV_SALES	DISTPRI		0.13863181	0.08051775	0.00537522	0.02024555	0.00029865	-	0.01974134	0.00347680	-	-	0.00065401	0.00819980	-	-	-	-	0.00012271	-	-
REV_SALES	DISTSEC		0.05853803	0.03740801	0.00339080	0.00900066	-	-	0.00765244	-	-	-	0.00020907	-	-	-	-	-	0.00004116	0.00065009	0.00018579
REV_SALES	ENERGY		0.39617879	0.13217692	0.00923202	0.03288171	0.00056346	0.00005945	0.03653897	0.00788912	0.00196349	0.00004346	0.00139094	0.02039982	0.02117020	0.00411327	0.10809418	0.01690479	0.00025260	0.00198540	0.00051897
REV_SALES	CUSTOMER		0.04326685	0.02159108	0.00630331	0.00202318	0.00041457	0.00010121	0.00052103	0.00012645	0.00029519	0.00003122	0.00000382	0.00006581	0.00038102	0.00006872	0.00015317	0.00004049	0.00000294	0.00948553	0.00165809
REV_SALES	TOTAL		1.00000000	0.41053053	0.03498410	0.10441034	0.00182696	0.00021708	0.10299344	0.01832918	0.00444196	0.00011931	0.00346998	0.04439163	0.04144967	0.00724158	0.18019319	0.02926934	0.00064982	0.01294401	0.00253786
Production EPIS	PRODUCTION		1,562,785,754	734,427,704	32,171,380	121,172,296	2,169,961	227,171	131,217,934	25,546,856	7,558,392	149,211	4,585,398	63,527,972	67,316,475	14,787,771	309,021,190	47,592,590	713,215	488,611	111,628
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		1,562,785,754	734,427,704	32,171,380	121,172,296	2,169,961	227,171	131,217,934	25,546,856	7,558,392	149,211	4,585,398	63,527,972	67,316,475	14,787,771	309,021,190	47,592,590	713,215	488,611	111,628
RB_GUP_EPIS_P	PRODUCTION		1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
RB_GUP_EPIS_P	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	TOTAL		1.00000000	0.46994779	0.02058592	0.07753609	0.00138852	0.00014536	0.08396412	0.01634700	0.00483649	0.00009548	0.00293412	0.04065047	0.04307467	0.00946244	0.19773740	0.03045369	0.00045637	0.00031265	0.00007143
Transmission EPIS	PRODUCTION		11,074,145	5,204,270	227,971	858,646	15,377	1,610	929,831	181,029	53,560	1,057	32,493	450,169	477,015	104,788	2,189,773	337,249	5,054	3,462	791
	BULKTRAN		401,062,596	188,478,479	8,256,242	31,096,825	556,884	58,300	33,674,869	6,556,170	1,939,734	38,293	1,176,765	16,303,382	17,275,637	3,795,032	79,305,075	12,213,835	183,035	125,394	28,647
	SUBTRAN		103,418,657	47,143,353	2,011,202	7,595,968	137,082	19,318	8,369,093	1,631,836	636,086	-	282,715	4,046,669	5,837,657	-	25,661,087	-	46,591	-	-
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		515,555,398	240,826,102	10,495,416	39,551,440	709,342	79,227	42,973,793	8,369,034	2,629,380	39,350	1,491,973	20,800,221	23,590,309	3,899,820	107,155,934	12,551,084	234,680	128,856	29,438
RB_GUP_EPIS_T	PRODUCTION		0.02148003	0.01009449	0.00044219	0.00166548	0.00002983	0.00000312	0.00180355	0.00035113	0.00010389	0.00000205	0.00006302	0.00087317	0.00092525	0.00020325	0.00424741	0.00065415	0.00000980	0.00000672	0.00000153
RB_GUP_EPIS_T	BULKTRAN		0.77792338	0.36558337	0.01601427	0.06031714	0.00108016	0.00011308	0.06531765	0.01271671	0.00376242	0.00007427	0.00228252	0.03162295	0.03350879	0.00736106	0.15382455	0.02369064	0.00035502	0.00024322	0.00005557
RB_GUP_EPIS_T	SUBTRAN		0.20059659	0.09144188	0.00390104	0.01473356	0.00026589	0.00003747	0.01623316	0.00316520	0.00123379	-	0.00054837	0.00784915	0.01132304	-	0.04977368	-	0.00009037	-	-
RB_GUP_EPIS_T	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	TOTAL		1.00000000	0.46711974	0.02035749	0.07671618	0.00137588	0.00015367	0.08335436	0.01623305	0.00510009	0.00007633	0.00289391	0.04034527	0.04575708	0.00756431	0.20784563	0.02434478	0.00045520	0.00024994	0.00005710
Distribution EPIS	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		410,287,990	276,449,686	11,704,110	42,282,722	757,363	-	46,147,866	8,987,151	-	-	1,674,901	22,020,200	-	-	-	-	263,991	-	-
	DISTSEC		202,781,578	150,560,567	8,230,513	20,878,200	-	-	20,127,847	-	-	-	605,972	-	-	-	-	-	98,703	1,877,620	402,156
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		103,230,312	45,630,505	12,170,606	3,714,589	1,247,917	313,705	1,299,845	382,465	771,525	57,630	10,403	203,981	1,002,983	288,147	518,665	115,259	5,620	32,056,390	3,440,078
	TOTAL		716,299,880	472,640,758	32,105,228	66,875,511	2,005,280	313,705	67,575,559	9,369,615	771,525	57,630	2,291,277	22,224,182	1,002,983	288,147	518,665	115,259	368,313	33,934,010	3,842,234
RB_GUP_EPIS_D	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	DISTPRI		0.57278802	0.38594127	0.01633968	0.05902936	0.00105733	-	0.06442534	0.01254663	-	-	0.00233827	0.03074159	-	-	-	-	0.00036855	-	-
RB_GUP_EPIS_D	DISTSEC		0.28309593	0.21019209	0.01149032	0.02914729	-	-	0.02809975	-	-	-	0.00084598	-	-	-	-	-	0.00013780	0.00262128	0.00056144
RB_GUP_EPIS_D	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	CUSTOMER		0.14411605	0.06370307	0.01699094	0.00518580	0.00174217	0.00043795	0.00181467	0.00053394	0.00107710	0.00008045	0.00001452	0.00028477	0.00140023	0.00040227	0.00072409	0.00016091	0.00000785	0.04475275	0.00480257
RB_GUP_EPIS_D	TOTAL		1.00000000	0.65983643	0.04482093	0.09336245	0.00279950	0.00043795	0.09433976	0.01308058	0.00107710	0.00008045	0.00319877	0.03102637	0.00140023	0.00040227	0.00072409	0.00016091	0.00051419	0.04737403	0.00536400

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
Gen & Int Plant	PRODUCTION	24,041,251	11,298,133	494,911	1,864,065	33,382	3,495	2,018,603	393,002	116,275	2,295	70,540	977,288	1,035,569	227,489	4,753,854	732,145	10,972	7,517	1,717
	BULKTRAN	1,044,718	490,963	21,506	81,003	1,451	152	87,719	17,078	5,053	100	3,065	42,468	45,001	9,886	206,580	31,816	477	327	75
	SUBTRAN	269,393	122,803	5,239	19,787	357	50	21,800	4,251	1,657	-	736	10,541	15,206	-	66,844	-	121	-	-
	DISTPRI	15,159,221	10,214,196	432,441	1,562,252	27,983	-	1,705,060	332,055	-	-	61,884	813,597	-	-	-	-	9,754	-	-
	DISTSEC	5,927,573	4,401,084	240,589	610,297	-	-	588,364	-	-	-	17,713	-	-	-	-	-	2,885	54,885	11,756
	ENERGY	3,129,799	1,112,148	70,172	247,713	4,449	474	276,010	53,317	15,865	312	11,038	157,314	161,142	30,797	828,838	135,736	1,902	18,538	4,034
	CUSTOMER	6,196,639	4,376,790	720,507	225,487	33,531	8,157	47,707	11,568	19,981	1,480	390	6,207	25,999	7,405	13,329	2,962	333	572,089	122,719
	TOTAL	55,768,593	32,016,116	1,985,365	4,610,604	101,152	12,327	4,745,262	811,271	158,830	4,187	165,366	2,007,416	1,282,917	275,576	5,869,445	902,659	26,444	653,356	140,300
RB_GUP_EPIS_G	PRODUCTION	0.43108943	0.20258952	0.00887437	0.03342499	0.00059858	0.00006266	0.03619605	0.00704702	0.00208496	0.00004116	0.00126487	0.01752399	0.01856903	0.00407916	0.08524250	0.01312826	0.00019674	0.00013478	0.00003079
RB_GUP_EPIS_G	BULKTRAN	0.01873309	0.00880357	0.00038564	0.00145249	0.00002601	0.00000272	0.00157291	0.00030623	0.00009060	0.00000179	0.00005497	0.00076151	0.00080692	0.00017726	0.00370423	0.00057049	0.00000855	0.00000586	0.00000134
RB_GUP_EPIS_G	SUBTRAN	0.00483055	0.00220200	0.00009394	0.00035480	0.00000640	0.00000090	0.00039091	0.00007622	0.00002971	-	0.00001321	0.00018901	0.00027267	-	0.00119859	-	0.00000218	-	-
RB_GUP_EPIS_G	DISTPRI	0.27182362	0.18315319	0.00775420	0.02801311	0.00050177	-	0.03057384	0.00595416	-	-	0.00110965	0.01458880	-	-	-	-	0.00017490	-	-
RB_GUP_EPIS_G	DISTSEC	0.10628873	0.07891689	0.00431405	0.01094339	-	-	0.01055009	-	-	-	0.00031762	-	-	-	-	-	0.00005174	0.00098416	0.00021079
RB_GUP_EPIS_G	ENERGY	0.05612117	0.01994219	0.00125828	0.00444180	0.00007978	0.00000850	0.00494919	0.00095604	0.00028447	0.00000559	0.00019793	0.00282084	0.00288947	0.00055223	0.01486209	0.00243392	0.00003411	0.00033241	0.00007233
RB_GUP_EPIS_G	CUSTOMER	0.11111342	0.07848128	0.01291958	0.00404327	0.00060125	0.00014626	0.00085544	0.00020742	0.00035828	0.00002653	0.00000698	0.00011130	0.00046619	0.00013278	0.00023901	0.00005311	0.00000596	0.01025827	0.00220051
RB_GUP_EPIS_G	TOTAL	1.00000000	0.57408864	0.03560006	0.08267384	0.00181379	0.00022104	0.08508842	0.01454710	0.00284802	0.00007507	0.00296522	0.03599546	0.02300429	0.00494142	0.10524643	0.01618579	0.00047417	0.01171547	0.00251576
CWIP	PRODUCTION	31,714,172	14,904,005	652,865	2,458,993	44,036	4,610	2,662,853	518,432	153,385	3,028	93,053	1,289,196	1,366,077	300,094	6,271,078	965,813	14,474	9,916	2,265
	BULKTRAN	28,965,204	13,612,134	596,275	2,245,849	40,219	4,210	2,432,038	473,494	140,090	2,766	84,987	1,177,449	1,247,666	274,082	5,727,504	882,097	13,219	9,056	2,069
	SUBTRAN	7,469,015	3,404,747	145,251	548,590	9,900	1,395	604,426	117,853	45,939	-	20,418	292,255	421,602	-	1,853,273	-	3,365	-	-
	DISTPRI	5,361,880	3,612,804	152,956	552,575	9,898	-	603,087	117,449	-	-	21,889	287,773	-	-	-	-	3,450	-	-
	DISTSEC	2,614,178	1,940,966	106,104	269,153	-	-	259,480	-	-	-	7,812	-	-	-	-	-	1,272	24,206	5,184
	ENERGY	71,784	25,508	1,609	5,681	102	11	6,330	1,223	364	7	253	3,608	3,696	706	19,010	3,113	44	425	93
	CUSTOMER	1,403,718	658,042	165,264	50,568	16,020	4,021	16,980	4,939	9,887	738	136	2,635	12,854	3,691	6,644	1,477	76	404,887	44,856
	TOTAL	77,599,950	38,158,205	1,820,326	6,131,409	120,175	14,247	6,585,193	1,233,390	349,665	6,539	228,548	3,052,916	3,051,896	578,573	13,877,510	1,852,501	35,900	448,490	54,468
RB_GUP_CWIP	PRODUCTION	0.40868804	0.19206204	0.00841322	0.03168807	0.00056747	0.00005941	0.03431513	0.00668082	0.00197661	0.00003902	0.00119914	0.01661336	0.01760410	0.00386719	0.08081291	0.01244606	0.00018651	0.00012778	0.00002919
RB_GUP_CWIP	BULKTRAN	0.37326318	0.17541420	0.00768397	0.02894137	0.00051828	0.00005426	0.03134072	0.00610173	0.00180528	0.00003564	0.00109520	0.01517332	0.01607819	0.00353198	0.07380809	0.01136724	0.00017035	0.00011670	0.00002666
RB_GUP_CWIP	SUBTRAN	0.09625025	0.04387564	0.00187180	0.00706946	0.00012758	0.00001798	0.00778899	0.00151873	0.00059200	-	0.00026312	0.00376618	0.00543302	-	0.02388240	-	0.00004336	-	-
RB_GUP_CWIP	DISTPRI	0.06909643	0.04655678	0.00197108	0.00712082	0.00012755	-	0.00777174	0.00151352	-	-	0.00028207	0.00370841	-	-	-	-	0.00004446	-	-
RB_GUP_CWIP	DISTSEC	0.03368788	0.02501246	0.00136733	0.00346847	-	-	0.00334382	-	-	-	0.00010067	-	-	-	-	-	0.00001640	0.00031193	0.00006681
RB_GUP_CWIP	ENERGY	0.00092505	0.00032871	0.00002074	0.00007321	0.00000131	0.00000014	0.00008158	0.00001576	0.00000469	0.00000009	0.00000326	0.00004650	0.00004763	0.00000910	0.00024497	0.00004012	0.00000056	0.00000548	0.00000119
RB_GUP_CWIP	CUSTOMER	0.01808916	0.00847993	0.00212969	0.00065165	0.00020644	0.00005182	0.00021881	0.00006365	0.00012741	0.00000951	0.00000175	0.00003396	0.00016564	0.00004757	0.00008562	0.00001903	0.00000098	0.00521762	0.00057805
RB_GUP_CWIP	TOTAL	1.00000000	0.49172976	0.02345783	0.07901305	0.00154864	0.00018360	0.08486079	0.01589422	0.00450599	0.00008426	0.00294521	0.03934173	0.03932858	0.00745584	0.17883400	0.02387244	0.00046263	0.00577951	0.00070190
T&D Plant	PRODUCTION	11,074,145	5,204,270	227,971	858,646	15,377	1,610	929,831	181,029	53,560	1,057	32,493	450,169	477,015	104,788	2,189,773	337,249	5,054	3,462	791
	BULKTRAN	401,754,562	188,803,667	8,270,487	31,150,478	557,845	58,400	33,732,969	6,567,481	1,943,080	38,359	1,178,795	16,331,511	17,305,444	3,801,580	79,441,902	12,234,908	183,350	125,610	28,697
	SUBTRAN	103,418,657	47,143,353	2,011,202	7,595,968	137,082	19,318	8,369,093	1,631,836	636,086	-	282,715	4,046,669	5,837,657	-	25,661,087	-	46,591	-	-
	DISTPRI	410,287,990	276,449,686	11,704,110	42,282,722	757,363	-	46,147,866	8,987,151	-	-	1,674,901	22,020,200	-	-	-	-	263,991	-	-
	DISTSEC	202,781,578	150,560,567	8,230,513	20,878,200	-	-	20,127,847	-	-	-	605,972	-	-	-	-	-	98,703	1,877,620	402,156
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	103,230,312	45,630,505	12,170,606	3,714,589	1,247,917	313,705	1,299,845	382,465	771,525	57,630	10,403	203,981	1,002,983	288,147	518,665	115,259	5,620	32,056,390	3,440,078
	TOTAL	1,232,547,244	713,792,048	42,614,889	106,480,603	2,715,583	393,033	110,607,452	17,749,961	3,404,252	97,046	3,785,280	43,052,531	24,623,098	4,194,515	107,811,427	12,687,415	603,308	34,063,082	3,871,722
TDPLANT	PRODUCTION	0.00898476	0.00422237	0.00018496	0.00069664	0.00001248	0.00000131	0.00075440	0.00014687	0.00004345	0.00000086	0.00002636	0.00036523	0.00038702	0.00008502	0.00177662	0.00027362	0.00000410	0.00000281	0.00000064
TDPLANT	BULKTRAN	0.32595470	0.15318169	0.00671008	0.02527325	0.00045259	0.00004738	0.02736850	0.00532838	0.00157648	0.00003112	0.00095639	0.01325021	0.01404039	0.00308433	0.06445343	0.00992652	0.00014876	0.00010191	0.00002328
TDPLANT	SUBTRAN	0.08390644	0.03824872	0.00163174	0.00616282	0.00011122	0.00001567	0.00679008	0.00132395	0.00051607	-	0.00022937	0.00328318	0.00473625	-	0.02081956	-	0.00003780	-	-
TDPLANT	DISTPRI	0.33287810	0.22429135	0.00949587	0.03430515	0.00061447	-	0.03744105	0.00729153	-	-	0.00135889	0.01786560	-	-	-	-	0.00021418	-	-
TDPLANT	DISTSEC	0.16452236	0.12215399	0.00667764	0.01693907	-	-	0.01633028	-	-	-	0.00049164	-	-	-	-	-	0.00008008	0.00152337	0.00032628
TDPLANT	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDPLANT	CUSTOMER	0.08375364	0.03702130	0.00987435	0.00301375	0.00101247	0.00025452	0.00105460	0.00031030	0.00062596	0.00004676	0.00000844	0.00016550	0.00081375	0.00023378	0.00042081	0.00009351	0.00000456	0.02600824	0.00279103
TDPLANT	TOTAL	1.00000000	0.57911942	0.03457465	0.08639069	0.00220323	0.00031888	0.08973891	0.01440104	0.00276196	0.00007874	0.00307110	0.03492972	0.01997741	0.00340313	0.08747042	0.01029365	0.00048948	0.02763633	0.00314124
Electric Plant in Service	PRODUCTION	1,538,833,598	723,171,441	31,678,303	119,315,139	2,136,703	223,689	129,206,812	25,155,310	7,442,548	146,924	4,515,120	62,554,306	66,284,743	14,561,125	304,284,953	46,863,158	702,284	481,122	109,917
	BULKTRAN	402,799,280	189,294,630	8,291,993	31,231,481	559,295	58,552	33,820,688	6,584,559	1,948,133	38,458	1,181,861	16,373,979	17,350,444	3,811,465	79,648,482	12,266,724	183,827	125,937	28,772
	SUBTRAN	103,688,050	47,266,156	2,016,441	7,615,755	137,439	19,368	8,390,893	1,636,087	637,743	-	283,451	4,057,210	5,852,863	-	25,727,931	-	46,712	-	-
	DISTPRI	425,447,211	286,663,882	12,136,550	43,844,974	785,346	-	47,852,927	9,319,206	-	-	1,736,785	22,833,797	-	-	-	-	273,744	-	-
	DISTSEC	208,709,151	154,961,651	8,471,102	21,488,497	-	-	20,716,210	-	-	-	623,686	-	-	-	-	-	101,588	1,932,505	413,912
	ENERGY	3,129,799	1,112,148	70,172	247,713	4,449	474	276,010	53,317	15,865	312	11,038	157,314	161,142	30,797	828,838	135,736	1,902	18,538	4,034
	CUSTOMER	109,426,951	50,007,295	12,891,113	3,940,076	1,281,448	321,861	1,347,552	394,032	791,506	59,109	10,793	210,188	1,028,981	295,552	531,994	118,221	5,952	32,628,479	3,562,797
	TOTAL	2,792,034,039	1,452,477,202	75,555,674	227,683,636	4,904,680	623,945	241,611,092	43,142,511	10,835,794	244,804	8,362,733	106,186,795	90,678,174	18,698,939	411,022,198	59,383,839	1,316,011	35,186,581	4,119,431
RB_GUP_EPIS	PRODUCTION	0.55115145	0.25901240	0.01134596	0.04273413	0.00076529	0.00008012	0.04627695	0.00900967	0.00266564	0.00005262	0.00161714	0.02240456	0.02374066	0.00521524	0.10898325	0.01678459	0.00025153	0.00017232	0.00003937
RB_GUP_EPIS	BULKTRAN	0.14426732	0.06779811	0.00296988	0.01118592	0.00020032	0.00002097	0.01211328	0.00235834	0.00069775	0.00001377	0.00042330	0.00586453	0.00621427	0.00136512	0.02852705	0.00439347	0.00006584	0.00004511	0.00001030
RB_GUP_EPIS	SUBTRAN	0.03713710	0.01692893	0.00072221	0.00272767	0.00004923	0.00000694	0.00300530	0.00058598	0.00022842	-	0.00010152	0.00145314	0.00209627	-	0.00921476	-	0.00001673	-	-
RB_GUP_EPIS	DISTPRI	0.15237895	0.10267206	0.00434685	0.01570360	0.00028128	-	0.01713909	0.00333778	-	-	0.00062205	0.00817819	-	-	-	-	0.00009804	-	-
RB_GUP_EPIS	DISTSEC	0.07475165	0.05550135	0.00303403	0.00769636	-	-	0.00741976	-	-	-	0.00022338	-	-	-	-	-	0.00003638	0.00069215	0.00014825
RB_GUP_EPIS	ENERGY	0.00112097	0.00039833	0.00002513	0.00008872	0.00000159	0.00000017	0.00009886	0.00001910	0.00000568	0.00000011	0.00000395	0.00005634	0.00005771	0.00001103	0.00029686	0.00004862	0.00000068	0.00000664	0.00000144
RB_GUP_EPIS	CUSTOMER	0.03919256	0.01791070	0.00461710	0.00141118	0.00045897	0.00011528	0.00048264	0.00014113	0.00028349	0.00002117	0.00000387	0.00007528	0.00036854	0.00010586	0.00019054	0.00004234	0.00000213	0.01168628	0.00127606
RB_GUP_EPIS	TOTAL	1.00000000	0.52022188	0.02706116	0.08154759	0.00175667	0.00022347	0.08653587	0.01545200	0.00388097	0.00008768	0.00299521	0.03803206	0.03247746	0.00669725	0.14721246	0.02126902	0.00047134	0.01260249	0.00147542
Gross Utility Plant	PRODUCTION	1,538,833,598	723,171,441	31,678,303	119,315,139	2,136,703	223,689	129,206,812	25,155,310	7,442,548	146,924	4,515,120	62,554,306	66,284,743	14,561,125	304,284,953	46,863,158	702,284	481,122	109,917
	BULKTRAN	402,799,280	189,294,630	8,291,993	31,231,481	559,295	58,552	33,820,688	6,584,559	1,948,133	38,458	1,181,861	16,373,979	17,350,444	3,811,465	79,648,482	12,266,724	183,827	125,937	28,772
	SUBTRAN	103,688,050	47,266,156	2,016,441	7,615,755	137,439	19,368	8,390,893	1,636,087	637,743	-	283,451	4,057,210	5,852,863	-	25,727,931	-	46,712	-	-
	DISTPRI	425,447,211	286,663,882	12,136,550	43,844,974	785,346	-	47,852,927	9,319,206	-	-	1,736,785	22,833,797	-	-	-	-	273,744	-	-
	DISTSEC	208,709,151	154,961,651	8,471,102	21,488,497	-	-	20,716,210	-	-	-	623,686	-	-	-	-	-	101,588	1,932,505	413,912
	ENERGY	3,129,799	1,112,148	70,172	247,713	4,449	474	276,010	53,317	15,865	312	11,038	157,314	161,142	30,797	828,838	135,736	1,902	18,538	4,034
	CUSTOMER	109,426,951	50,007,295	12,891,113	3,940,076	1,281,448	321,861	1,347,552	394,032	791,506	59,109	10,793	210,188	1,028,981	295,552	531,994	118,221	5,952	32,628,479	3,562,797
	TOTAL	2,792,034,039	1,452,477,202	75,555,674	227,683,636	4,904,680	623,945	241,611,092	43,142,511	10,835,794	244,804	8,362,733	106,186,795	90,678,174	18,698,939	411,022,198	59,383,839	1,316,011	35,186,581	4,119,431
RB_GUP	PRODUCTION	0.55115145	0.25901240	0.01134596	0.04273413	0.00076529	0.00008012	0.04627695	0.00900967	0.00266564	0.00005262	0.00161714	0.02240456	0.02374066	0.00521524	0.10898325	0.01678459	0.00025153	0.00017232	0.00003937
RB_GUP	BULKTRAN	0.14426732	0.06779811	0.00296988	0.01118592	0.00020032	0.00002097	0.01211328	0.00235834	0.00069775	0.00001377	0.00042330	0.00586453	0.00621427	0.00136512	0.02852705	0.00439347	0.00006584	0.00004511	0.00001030
RB_GUP	SUBTRAN	0.03713710	0.01692893	0.00072221	0.00272767	0.00004923	0.00000694	0.00300530	0.00058598	0.00022842	-	0.00010152	0.00145314	0.00209627	-	0.00921476	-	0.00001673	-	-
RB_GUP	DISTPRI	0.15237895	0.10267206	0.00434685	0.01570360	0.00028128	-	0.01713909	0.00333778	-	-	0.00062205	0.00817819	-	-	-	-	0.00009804	-	-
RB_GUP	DISTSEC	0.07475165	0.05550135	0.00303403	0.00769636	-	-	0.00741976	-	-	-	0.00022338	-	-	-	-	-	0.00003638	0.00069215	0.00014825
RB_GUP	ENERGY	0.00112097	0.00039833	0.00002513	0.00008872	0.00000159	0.00000017	0.00009886	0.00001910	0.00000568	0.00000011	0.00000395	0.00005634	0.00005771	0.00001103	0.00029686	0.00004862	0.00000068	0.00000664	0.00000144
RB_GUP	CUSTOMER	0.03919256	0.01791070	0.00461710	0.00141118	0.00045897	0.00011528	0.00048264	0.00014113	0.00028349	0.00002117	0.00000387	0.00007528	0.00036854	0.00010586	0.00019054	0.00004234	0.00000213	0.01168628	0.00127606
RB_GUP	TOTAL	1.00000000	0.52022188	0.02706116	0.08154759	0.00175667	0.00022347	0.08653587	0.01545200	0.00388097	0.00008768	0.00299521	0.03803206	0.03247746	0.00669725	0.14721246	0.02126902	0.00047134	0.01260249	0.00147542

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
Net EPIS	PRODUCTION	435,482,125	204,653,860	8,964,799	33,765,581	604,676	63,303	36,564,874	7,118,826	2,106,203	41,579	1,277,756	17,702,552	18,758,247	4,120,725	86,111,103	13,262,037	198,743	136,155	31,106
	BULKTRAN	276,497,133	129,939,215	5,691,947	21,438,506	383,922	40,192	23,215,839	4,519,898	1,337,275	26,399	811,275	11,239,738	11,910,022	2,616,338	54,673,824	8,420,357	126,186	86,448	19,750
	SUBTRAN	71,372,976	32,535,342	1,388,004	5,242,254	94,605	13,332	5,775,815	1,126,189	438,986	-	195,112	2,792,754	4,028,779	-	17,709,650	-	32,154	-	-
	DISTPRI	309,433,431	208,494,465	8,827,075	31,889,034	571,193	-	34,804,072	6,777,983	-	-	1,263,187	16,607,325	-	-	-	-	199,098	-	-
	DISTSEC	151,810,755	112,715,926	6,161,706	15,630,292	-	-	15,068,546	-	-	-	453,656	-	-	-	-	-	73,893	1,405,664	301,071
	ENERGY	2,248,730	799,068	50,418	177,980	3,197	340	198,310	38,308	11,399	224	7,931	113,029	115,779	22,127	595,512	97,525	1,367	13,319	2,898
	CUSTOMER	79,566,660	36,347,232	9,373,489	2,864,891	932,125	234,124	980,095	286,608	575,748	42,997	7,850	152,885	748,489	214,988	386,978	85,995	4,328	23,736,531	2,591,308
	TOTAL	1,326,411,811	725,485,108	40,457,438	111,008,539	2,589,718	351,292	116,607,553	19,867,811	4,469,611	111,199	4,016,767	48,608,282	35,561,316	6,974,178	159,477,066	21,865,914	635,769	25,378,117	2,946,133
NP	PRODUCTION	0.32831593	0.15429134	0.00675868	0.02545633	0.00045587	0.00004772	0.02756676	0.00536698	0.00158790	0.00003135	0.00096332	0.01334620	0.01414210	0.00310667	0.06492034	0.00999843	0.00014983	0.00010265	0.00002345
NP	BULKTRAN	0.20845497	0.09796295	0.00429124	0.01616278	0.00028944	0.00003030	0.01750274	0.00340761	0.00100819	0.00001990	0.00061163	0.00847379	0.00897913	0.00197249	0.04121934	0.00634822	0.00009513	0.00006517	0.00001489
NP	SUBTRAN	0.05380906	0.02452884	0.00104644	0.00395221	0.00007132	0.00001005	0.00435447	0.00084905	0.00033096	-	0.00014710	0.00210550	0.00303735	-	0.01335155	-	0.00002424	-	-
NP	DISTPRI	0.23328609	0.15718683	0.00665485	0.02404158	0.00043063	-	0.02623927	0.00511001	-	-	0.00095233	0.01252049	-	-	-	-	0.00015010	-	-
NP	DISTSEC	0.11445220	0.08497808	0.00464539	0.01178389	-	-	0.01136038	-	-	-	0.00034202	-	-	-	-	-	0.00005571	0.00105975	0.00022698
NP	ENERGY	0.00169535	0.00060243	0.00003801	0.00013418	0.00000241	0.00000026	0.00014951	0.00002888	0.00000859	0.00000017	0.00000598	0.00008521	0.00008729	0.00001668	0.00044896	0.00007353	0.00000103	0.00001004	0.00000218
NP	CUSTOMER	0.05998639	0.02740267	0.00706680	0.00215988	0.00070274	0.00017651	0.00073891	0.00021608	0.00043406	0.00003242	0.00000592	0.00011526	0.00056430	0.00016208	0.00029175	0.00006483	0.00000326	0.01789530	0.00195362
NP	TOTAL	1.00000000	0.54695314	0.03050142	0.08369086	0.00195242	0.00026484	0.08791203	0.01497861	0.00336970	0.00008383	0.00302830	0.03664645	0.02681016	0.00525793	0.12023194	0.01648501	0.00047931	0.01913291	0.00222113
Rate Base	PRODUCTION	343,373,290	158,043,405	6,871,872	26,489,788	253,544	18,384	29,435,549	5,667,206	1,607,429	13,254	1,042,848	14,220,448	14,987,341	3,127,440	70,493,688	10,805,026	162,609	108,095	25,364
	BULKTRAN	241,732,514	112,794,873	4,922,888	18,700,951	277,793	26,940	20,441,267	3,932,018	1,159,410	17,964	719,691	9,893,514	10,465,143	2,248,398	48,451,336	7,474,396	111,847	76,562	17,527
	SUBTRAN	62,468,563	28,259,368	1,201,193	4,575,492	68,540	8,950	5,088,312	980,279	380,827	-	173,176	2,459,601	3,541,981	-	15,702,328	-	28,515	-	-
	DISTPRI	256,459,691	172,269,554	7,274,522	26,503,356	393,681	-	29,202,596	5,657,988	-	-	1,065,664	13,924,245	-	-	-	-	168,085	-	-
	DISTSEC	125,239,747	92,779,117	5,058,088	12,940,130	-	-	12,594,464	-	-	-	381,317	-	-	-	-	-	62,146	1,171,474	253,011
	ENERGY	62,775,823	22,157,602	1,412,478	4,987,091	87,669	9,334	5,571,635	1,141,118	309,497	6,230	218,873	3,163,003	3,232,884	632,898	16,721,444	2,664,154	38,258	342,120	79,537
	CUSTOMER	66,136,888	30,510,455	7,751,874	2,390,708	636,482	148,057	818,800	237,512	470,217	27,646	6,596	127,350	621,195	174,922	324,045	71,941	3,666	19,638,926	2,176,496
	TOTAL	1,158,186,516	616,814,372	34,492,915	96,587,516	1,717,708	211,664	103,152,623	17,616,122	3,927,380	65,094	3,608,164	43,788,162	32,848,544	6,183,658	151,692,839	21,015,516	575,126	21,337,177	2,551,935
RATEBASE	PRODUCTION	0.29647495	0.13645765	0.00593330	0.02287178	0.00021891	0.00001587	0.02541521	0.00489317	0.00138788	0.00001144	0.00090041	0.01227820	0.01294035	0.00270029	0.06086557	0.00932926	0.00014040	0.00009333	0.00002190
RATEBASE	BULKTRAN	0.20871639	0.09738921	0.00425051	0.01614675	0.00023985	0.00002326	0.01764937	0.00339498	0.00100106	0.00001551	0.00062139	0.00854225	0.00903580	0.00194131	0.04183379	0.00645353	0.00009657	0.00006611	0.00001513
RATEBASE	SUBTRAN	0.05393653	0.02439967	0.00103713	0.00395057	0.00005918	0.00000773	0.00439334	0.00084639	0.00032881	-	0.00014952	0.00212367	0.00305821	-	0.01355769	-	0.00002462	-	-
RATEBASE	DISTPRI	0.22143212	0.14874077	0.00628096	0.02288350	0.00033991	-	0.02521407	0.00488521	-	-	0.00092011	0.01202245	-	-	-	-	0.00014513	-	-
RATEBASE	DISTSEC	0.10813435	0.08010723	0.00436725	0.01117275	-	-	0.01087430	-	-	-	0.00032924	-	-	-	-	-	0.00005366	0.00101147	0.00021845
RATEBASE	ENERGY	0.05420183	0.01913129	0.00121956	0.00430595	0.00007569	0.00000806	0.00481065	0.00098526	0.00026723	0.00000538	0.00018898	0.00273100	0.00279133	0.00054646	0.01443761	0.00230028	0.00003303	0.00029539	0.00006867
RATEBASE	CUSTOMER	0.05710383	0.02634330	0.00669311	0.00206418	0.00054955	0.00012783	0.00070697	0.00020507	0.00040599	0.00002387	0.00000570	0.00010996	0.00053635	0.00015103	0.00027979	0.00006211	0.00000317	0.01695662	0.00187923
RATEBASE	TOTAL	1.00000000	0.53256912	0.02978183	0.08339548	0.00148310	0.00018275	0.08906391	0.01521009	0.00339097	0.00005620	0.00311536	0.03780752	0.02836205	0.00533909	0.13097445	0.01814519	0.00049657	0.01842292	0.00220339
System Sales	PRODUCTION	(519,481)	(244,129)	(10,694)	(40,279)	(721)	(76)	(43,618)	(8,492)	(2,512)	(50)	(1,524)	(21,117)	(22,376)	(4,916)	(102,721)	(15,820)	(237)	(162)	(37)
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	(219,455,800)	(77,981,782)	(4,920,352)	(17,369,201)	(311,952)	(33,226)	(19,353,287)	(3,738,507)	(1,112,395)	(21,875)	(773,965)	(11,030,593)	(11,298,980)	(2,159,419)	(58,116,624)	(9,517,569)	(133,390)	(1,299,849)	(282,834)
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	(219,975,281)	(78,225,911)	(4,931,046)	(17,409,479)	(312,673)	(33,301)	(19,396,905)	(3,746,999)	(1,114,908)	(21,924)	(775,490)	(11,051,710)	(11,321,356)	(2,164,335)	(58,219,345)	(9,533,389)	(133,627)	(1,300,011)	(282,872)
EXP_OM_SS	PRODUCTION	0.00236154	0.00110980	0.00004861	0.00018310	0.00000328	0.00000034	0.00019828	0.00003860	0.00001142	0.00000023	0.00000693	0.00009600	0.00010172	0.00002235	0.00046697	0.00007192	0.00000108	0.00000074	0.00000017
EXP_OM_SS	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS	ENERGY	0.99763846	0.35450248	0.02236775	0.07895978	0.00141812	0.00015104	0.08797937	0.01699512	0.00505691	0.00009944	0.00351842	0.05014469	0.05136477	0.00981664	0.26419616	0.04326654	0.00060639	0.00590907	0.00128576
EXP_OM_SS	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_SS	TOTAL	1.00000000	0.35561228	0.02241636	0.07914289	0.00142140	0.00015139	0.08817766	0.01703373	0.00506833	0.00009967	0.00352535	0.05024069	0.05146649	0.00983899	0.26466312	0.04333846	0.00060746	0.00590981	0.00128592
CUST_451	TOTAL	1.00000000	0.89529643	0.07229171	0.02502863	0.00036697	-	0.00042959	0.00007476	-	-	-	0.00010418	0.00001591	-	-	0.00001591	-	0.00637590	-
RB_GUP_EPIS_D	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	DISTPRI	0.57278802	0.38594127	0.01633968	0.05902936	0.00105733	-	0.06442534	0.01254663	-	-	0.00233827	0.03074159	-	-	-	-	0.00036855	-	-
RB_GUP_EPIS_D	DISTSEC	0.28309593	0.21019209	0.01149032	0.02914729	-	-	0.02809975	-	-	-	0.00084598	-	-	-	-	-	0.00013780	0.00262128	0.00056144
RB_GUP_EPIS_D	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	CUSTOMER	0.14411605	0.06370307	0.01699094	0.00518580	0.00174217	0.00043795	0.00181467	0.00053394	0.00107710	0.00008045	0.00001452	0.00028477	0.00140023	0.00040227	0.00072409	0.00016091	0.00000785	0.04475275	0.00480257
RB_GUP_EPIS_D	TOTAL	1.00000000	0.65983643	0.04482093	0.09336245	0.00279950	0.00043795	0.09433976	0.01308058	0.00107710	0.00008045	0.00319877	0.03102637	0.00140023	0.00040227	0.00072409	0.00016091	0.00051419	0.04737403	0.00536400
MISC_SERV_REV	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	DISTPRI	0.56644866	0.52366287	0.02635428	0.01582461	0.00013860	-	0.00029337	0.00007171	-	-	-	0.00010322	-	-	-	-	-	-	-
MISC_SERV_REV	DISTSEC	0.31202559	0.28519829	0.01853274	0.00781381	-	-	0.00012796	-	-	-	-	-	-	-	-	-	-	0.00035279	-
MISC_SERV_REV	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	CUSTOMER	0.12152575	0.08643526	0.02740469	0.00139021	0.00022837	-	0.00000826	0.00000305	-	-	-	0.00000096	0.00001591	-	-	0.00001591	-	0.00602312	-
MISC_SERV_REV	TOTAL	1.00000000	0.89529643	0.07229171	0.02502863	0.00036697	-	0.00042959	0.00007476	-	-	-	0.00010418	0.00001591	-	-	0.00001591	-	0.00637590	-

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
364 Poles	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	103,620,433	69,818,851	2,955,936	10,678,728	191,276	-	11,654,891	2,269,753	-	-	423,005	5,561,320	-	-	-	-	66,672	-	-
	DISTSEC	80,921,745	60,082,499	3,284,457	8,331,627	-	-	8,032,192	-	-	-	241,819	-	-	-	-	-	39,388	749,280	160,484
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	184,542,178	129,901,350	6,240,393	19,010,355	191,276	-	19,687,083	2,269,753	-	-	664,824	5,561,320	-	-	-	-	106,060	749,280	160,484
365 Overhead Lines	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	162,855,574	109,731,148	4,645,711	16,783,277	300,620	-	18,317,468	3,567,269	-	-	664,818	8,740,476	-	-	-	-	104,786	-	-
	DISTSEC	25,503,868	18,936,024	1,035,153	2,625,854	-	-	2,531,482	-	-	-	76,213	-	-	-	-	-	12,414	236,148	50,579
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	188,359,442	128,667,172	5,680,864	19,409,131	300,620	-	20,848,951	3,567,269	-	-	741,032	8,740,476	-	-	-	-	117,200	236,148	50,579
TOTOHLINES	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	DISTPRI	0.71460136	0.48149429	0.02038513	0.07364410	0.00131910	-	0.08037605	0.01565298	-	-	0.00291719	0.03835273	-	-	-	-	0.00045979	-	-
TOTOHLINES	DISTSEC	0.28539864	0.21190180	0.01158378	0.02938437	-	-	0.02832831	-	-	-	0.00085286	-	-	-	-	-	0.00013892	0.00264260	0.00056600
TOTOHLINES	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	TOTAL	1.00000000	0.69339608	0.03196891	0.10302848	0.00131910	-	0.10870436	0.01565298	-	-	0.00377004	0.03835273	-	-	-	-	0.00059871	0.00264260	0.00056600
366 Underground Conduit	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	4,919,948	3,315,032	140,349	507,031	9,082	-	553,380	107,769	-	-	20,084	264,054	-	-	-	-	3,166	-	-
	DISTSEC	1,841,937	1,367,595	74,761	189,644	-	-	182,828	-	-	-	5,504	-	-	-	-	-	897	17,055	3,653
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	6,761,885	4,682,628	215,110	696,675	9,082	-	736,208	107,769	-	-	25,589	264,054	-	-	-	-	4,062	17,055	3,653
367 Underground Lines	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	7,341,028	4,946,342	209,414	756,538	13,551	-	825,695	160,801	-	-	29,968	393,994	-	-	-	-	4,723	-	-
	DISTSEC	2,748,345	2,040,582	111,550	282,967	-	-	272,797	-	-	-	8,213	-	-	-	-	-	1,338	25,448	5,451
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	10,089,373	6,986,924	320,964	1,039,505	13,551	-	1,098,492	160,801	-	-	38,181	393,994	-	-	-	-	6,061	25,448	5,451
TOTUGLINES	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	DISTPRI	0.72760000	0.49025269	0.02075593	0.07498369	0.00134310	-	0.08183810	0.01593771	-	-	0.00297025	0.03905037	-	-	-	-	0.00046816	-	-
TOTUGLINES	DISTSEC	0.27240000	0.20225061	0.01105619	0.02804605	-	-	0.02703808	-	-	-	0.00081401	-	-	-	-	-	0.00013259	0.00252224	0.00054022
TOTUGLINES	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	TOTAL	1.00000000	0.69250331	0.03181212	0.10302974	0.00134310	-	0.10887618	0.01593771	-	-	0.00378426	0.03905037	-	-	-	-	0.00060075	0.00252224	0.00054022
Acct 581-589	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(Excluding Severance)	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	4,303,952	2,899,978	122,777	443,549	7,945	-	484,095	94,276	-	-	17,570	230,994	-	-	-	-	2,769	-	-
	DISTSEC	1,735,476	1,288,550	70,440	178,683	-	-	172,261	-	-	-	5,186	-	-	-	-	-	845	16,069	3,442
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	1,988,946	839,884	328,282	100,738	53,229	13,362	49,334	16,356	32,864	2,455	395	8,723	42,723	12,274	22,093	4,910	152	290,362	170,811
	TOTAL	8,028,374	5,028,412	521,499	722,970	61,173	13,362	705,690	110,632	32,864	2,455	23,151	239,717	42,723	12,274	22,093	4,910	3,766	306,432	174,253
TOTOXEXP	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	DISTPRI	0.53609267	0.36121615	0.01529289	0.05524767	0.00098959	-	0.06029797	0.01174284	-	-	0.00218847	0.02877215	-	-	-	-	0.00034494	-	-
TOTOXEXP	DISTSEC	0.21616776	0.16049949	0.00877383	0.02225643	-	-	0.02145654	-	-	-	0.00064597	-	-	-	-	-	0.00010522	0.00200157	0.00042870
TOTOXEXP	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	CUSTOMER	0.24773957	0.10461445	0.04089024	0.01254772	0.00663006	0.00166440	0.00614495	0.00203733	0.00409342	0.00030576	0.00004923	0.00108657	0.00532145	0.00152880	0.00275184	0.00061152	0.00001888	0.03616703	0.02127591
TOTOXEXP	TOTAL	1.00000000	0.62633010	0.06495696	0.09005182	0.00761965	0.00166440	0.08789946	0.01378016	0.00409342	0.00030576	0.00288367	0.02985873	0.00532145	0.00152880	0.00275184	0.00061152	0.00046904	0.03816859	0.02170462
Acct 591-598	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	25,000,290	16,845,051	713,173	2,576,435	46,149	-	2,811,952	547,619	-	-	102,058	1,341,768	-	-	-	-	16,086	-	-
	DISTSEC	9,718,683	7,215,894	394,463	1,000,626	-	-	964,664	-	-	-	29,042	-	-	-	-	-	4,731	89,988	19,274
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	321,766	33,950	19,801	6,099	4,039	1,015	3,586	1,238	2,497	187	29	660	3,247	933	1,679	373	9	189,656	52,768
	TOTAL	35,040,739	24,094,895	1,127,436	3,583,161	50,188	1,015	3,780,202	548,857	2,497	187	131,129	1,342,429	3,247	933	1,679	373	20,826	279,644	72,042
TOTMXEXP	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	DISTPRI	0.71346355	0.48072763	0.02035267	0.07352684	0.00131700	-	0.08024807	0.01562806	-	-	0.00291254	0.03829166	-	-	-	-	0.00045906	-	-
TOTMXEXP	DISTSEC	0.27735383	0.20592871	0.01125726	0.02855609	-	-	0.02752980	-	-	-	0.00082882	-	-	-	-	-	0.00013500	0.00256811	0.00055005
TOTMXEXP	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	CUSTOMER	0.00918263	0.00096886	0.00056508	0.00017407	0.00011528	0.00002898	0.00010233	0.00003533	0.00007127	0.00000532	0.00000082	0.00001884	0.00009265	0.00002662	0.00004791	0.00001065	0.00000026	0.00541244	0.00150590
TOTMXEXP	TOTAL	1.00000000	0.68762520	0.03217501	0.10225700	0.00143228	0.00002898	0.10788020	0.01566339	0.00007127	0.00000532	0.00374218	0.03831051	0.00009265	0.00002662	0.00004791	0.00001065	0.00059432	0.00798055	0.00205595

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
Acct 560-574	PRODUCTION	10,874,895	5,110,633	223,870	843,197	15,100	1,581	913,101	177,772	52,596	1,038	31,908	442,070	468,432	102,903	2,150,373	331,181	4,963	3,400	777
	BULKTRAN	7,590,425	3,567,103	156,256	588,532	10,539	1,103	637,323	124,081	36,711	725	22,271	308,554	326,955	71,824	1,500,911	231,156	3,464	2,373	542
	SUBTRAN	1,957,279	892,225	38,064	143,760	2,594	366	158,392	30,884	12,038	-	5,351	76,586	110,482	-	485,656	-	882	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	20,422,599	9,569,961	418,189	1,575,488	28,234	3,050	1,708,816	332,736	101,346	1,763	59,530	827,210	905,870	174,727	4,136,941	562,337	9,309	5,773	1,319
EXP_OM_TRAN	PRODUCTION	0.53249320	0.25024400	0.01096186	0.04128744	0.00073938	0.00007740	0.04471032	0.00870467	0.00257540	0.00005084	0.00156240	0.02164610	0.02293697	0.00503869	0.10529382	0.01621638	0.00024302	0.00016649	0.00003804
EXP_OM_TRAN	BULKTRAN	0.37166791	0.17466451	0.00765113	0.02881768	0.00051607	0.00005403	0.03120677	0.00607565	0.00179757	0.00003549	0.00109052	0.01510847	0.01600947	0.00351689	0.07349265	0.01131866	0.00016962	0.00011620	0.00002655
EXP_OM_TRAN	SUBTRAN	0.09583889	0.04368812	0.00186380	0.00703924	0.00012703	0.00001790	0.00775571	0.00151224	0.00058947	-	0.00026199	0.00375008	0.00540980	-	0.02378033	-	0.00004318	-	-
EXP_OM_TRAN	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	TOTAL	1.00000000	0.46859663	0.02047678	0.07714436	0.00138248	0.00014933	0.08367280	0.01629256	0.00496243	0.00008633	0.00291491	0.04050465	0.04435624	0.00855557	0.20256680	0.02753504	0.00045581	0.00028269	0.00006458
Acct 580-598	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	29,667,747	19,989,957	846,319	3,057,445	54,765	-	3,336,932	649,857	-	-	121,111	1,592,271	-	-	-	-	19,089	-	-
	DISTSEC	11,600,711	8,613,256	470,850	1,194,398	-	-	1,151,472	-	-	-	34,666	-	-	-	-	-	5,647	107,415	23,007
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	2,477,973	944,457	375,688	115,308	61,744	15,502	57,068	18,970	38,124	2,848	457	10,117	49,562	14,239	25,629	5,695	173	504,446	237,945
	TOTAL	43,746,431	29,547,670	1,692,858	4,367,152	116,509	15,502	4,545,473	668,827	38,124	2,848	156,235	1,602,388	49,562	14,239	25,629	5,695	24,909	611,860	260,952
EXP_OM_DIST	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	DISTPRI	0.67817526	0.45695059	0.01934601	0.06989017	0.00125186	-	0.07627896	0.01485509	-	-	0.00276849	0.03639774	-	-	-	-	0.00043636	-	-
EXP_OM_DIST	DISTSEC	0.26518074	0.19689048	0.01076317	0.02730276	-	-	0.02632151	-	-	-	0.00079244	-	-	-	-	-	0.00012907	0.00245539	0.00052591
EXP_OM_DIST	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	CUSTOMER	0.05664400	0.02158935	0.00858785	0.00263583	0.00141141	0.00035435	0.00130452	0.00043363	0.00087149	0.00006510	0.00001045	0.00023127	0.00113293	0.00032548	0.00058586	0.00013019	0.00000397	0.01153113	0.00543919
EXP_OM_DIST	TOTAL	1.00000000	0.67543042	0.03869704	0.09982875	0.00266327	0.00035435	0.10390499	0.01528872	0.00087149	0.00006510	0.00357138	0.03662901	0.00113293	0.00032548	0.00058586	0.00013019	0.00056940	0.01398652	0.00596509
Acct 560-598	PRODUCTION	10,874,895	5,110,633	223,870	843,197	15,100	1,581	913,101	177,772	52,596	1,038	31,908	442,070	468,432	102,903	2,150,373	331,181	4,963	3,400	777
	BULKTRAN	7,590,425	3,567,103	156,256	588,532	10,539	1,103	637,323	124,081	36,711	725	22,271	308,554	326,955	71,824	1,500,911	231,156	3,464	2,373	542
	SUBTRAN	1,957,279	892,225	38,064	143,760	2,594	366	158,392	30,884	12,038	-	5,351	76,586	110,482	-	485,656	-	882	-	-
	DISTPRI	29,667,747	19,989,957	846,319	3,057,445	54,765	-	3,336,932	649,857	-	-	121,111	1,592,271	-	-	-	-	19,089	-	-
	DISTSEC	11,600,711	8,613,256	470,850	1,194,398	-	-	1,151,472	-	-	-	34,666	-	-	-	-	-	5,647	107,415	23,007
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	2,477,973	944,457	375,688	115,308	61,744	15,502	57,068	18,970	38,124	2,848	457	10,117	49,562	14,239	25,629	5,695	173	504,446	237,945
	TOTAL	64,169,030	39,117,631	2,111,047	5,942,640	144,743	18,551	6,254,289	1,001,563	139,470	4,611	215,765	2,429,599	955,431	188,966	4,162,570	568,033	34,218	617,634	262,270
TDOMX	PRODUCTION	0.16947264	0.07964329	0.00348875	0.01314025	0.00023532	0.00002464	0.01422962	0.00277037	0.00081965	0.00001618	0.00049725	0.00688914	0.00729998	0.00160363	0.03351108	0.00516107	0.00007734	0.00005299	0.00001211
TDOMX	BULKTRAN	0.11828798	0.05558917	0.00243507	0.00917159	0.00016425	0.00001719	0.00993195	0.00193365	0.00057210	0.00001129	0.00034707	0.00480846	0.00509522	0.00111929	0.02338996	0.00360231	0.00005398	0.00003698	0.00000845
TDOMX	SUBTRAN	0.03050193	0.01390429	0.00059318	0.00224033	0.00004043	0.00000570	0.00246835	0.00048129	0.00018760	-	0.00008338	0.00119351	0.00172174	-	0.00756839	-	0.00001374	-	-
TDOMX	DISTPRI	0.46233747	0.31152033	0.01318890	0.04764674	0.00085344	-	0.05200222	0.01012727	-	-	0.00188738	0.02481370	-	-	-	-	0.00029748	-	-
TDOMX	DISTSEC	0.18078364	0.13422762	0.00733766	0.01861331	-	-	0.01794436	-	-	-	0.00054024	-	-	-	-	-	0.00008800	0.00167393	0.00035853
TDOMX	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDOMX	CUSTOMER	0.03861634	0.01471827	0.00585466	0.00179694	0.00096221	0.00024157	0.00088934	0.00029562	0.00059413	0.00004438	0.00000713	0.00015767	0.00077236	0.00022189	0.00039941	0.00008876	0.00000270	0.00786120	0.00370810
TDOMX	TOTAL	1.00000000	0.60960297	0.03289822	0.09260916	0.00225564	0.00028910	0.09746584	0.01560820	0.00217348	0.00007185	0.00336245	0.03786248	0.01488929	0.00294481	0.06486883	0.00885213	0.00053325	0.00962511	0.00408718
Acct 902-904	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	5,797,811	4,960,525	616,391	197,685	2,371	282	22,530	2,293	612	30	193	1,286	836	160	289	64	284	(9,294)	1,273
	TOTAL	5,797,811	4,960,525	616,391	197,685	2,371	282	22,530	2,293	612	30	193	1,286	836	160	289	64	284	(9,294)	1,273
TOTOX234	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	CUSTOMER	1.00000000	0.85558580	0.10631437	0.03409641	0.00040902	0.00004864	0.00388589	0.00039557	0.00010559	0.00000512	0.00003335	0.00022185	0.00014419	0.00002762	0.00004986	0.00001112	0.00004905	(0.00160304)	0.00021957
TOTOX234	TOTAL	1.00000000	0.85558580	0.10631437	0.03409641	0.00040902	0.00004864	0.00388589	0.00039557	0.00010559	0.00000512	0.00003335	0.00022185	0.00014419	0.00002762	0.00004986	0.00001112	0.00004905	(0.00160304)	0.00021957

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
Acct 901-905	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	6,109,997	5,227,627	649,580	208,329	2,499	297	23,743	2,417	645	31	204	1,355	881	169	305	68	300	(9,795)	1,342
	TOTAL	6,109,997	5,227,627	649,580	208,329	2,499	297	23,743	2,417	645	31	204	1,355	881	169	305	68	300	(9,795)	1,342
EXP_OM_CUSTACCT	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	CUSTOMER	1.00000000	0.85558580	0.10631437	0.03409641	0.00040902	0.00004864	0.00388589	0.00039557	0.00010559	0.00000512	0.00003335	0.00022185	0.00014419	0.00002762	0.00004986	0.00001112	0.00004905	(0.00160304)	0.00021957
EXP_OM_CUSTACCT	TOTAL	1.00000000	0.85558580	0.10631437	0.03409641	0.00040902	0.00004864	0.00388589	0.00039557	0.00010559	0.00000512	0.00003335	0.00022185	0.00014419	0.00002762	0.00004986	0.00001112	0.00004905	(0.00160304)	0.00021957
A&G Regulatory																				
REVSALES	TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
RB_GUP	PRODUCTION	0.55115145	0.25901240	0.01134596	0.04273413	0.00076529	0.00008012	0.04627695	0.00900967	0.00266564	0.00005262	0.00161714	0.02240456	0.02374066	0.00521524	0.10898325	0.01678459	0.00025153	0.00017232	0.00003937
	BULKTRAN	0.14426732	0.06779811	0.00296988	0.01118592	0.00020032	0.00002097	0.01211328	0.00235834	0.00069775	0.00001377	0.00042330	0.00586453	0.00621427	0.00136512	0.02852705	0.00439347	0.00006584	0.00004511	0.00001030
	SUBTRAN	0.03713710	0.01692893	0.00072221	0.00272767	0.00004923	0.00000694	0.00300530	0.00058598	0.00022842	-	0.00010152	0.00145314	0.00209627	-	0.00921476	-	0.00001673	-	-
	DISTPRI	0.15237895	0.10267206	0.00434685	0.01570360	0.00028128	-	0.01713909	0.00333778	-	-	0.00062205	0.00817819	-	-	-	-	0.00009804	-	-
	DISTSEC	0.07475165	0.05550135	0.00303403	0.00769636	-	-	0.00741976	-	-	-	0.00022338	-	-	-	-	-	0.00003638	0.00069215	0.00014825
	ENERGY	0.00112097	0.00039833	0.00002513	0.00008872	0.00000159	0.00000017	0.00009886	0.00001910	0.00000568	0.00000011	0.00000395	0.00005634	0.00005771	0.00001103	0.00029686	0.00004862	0.00000068	0.00000664	0.00000144
	CUSTOMER	0.03919256	0.01791070	0.00461710	0.00141118	0.00045897	0.00011528	0.00048264	0.00014113	0.00028349	0.00002117	0.00000387	0.00007528	0.00036854	0.00010586	0.00019054	0.00004234	0.00000213	0.01168628	0.00127606
	TOTAL	1.00000000	0.52022188	0.02706116	0.08154759	0.00175667	0.00022347	0.08653587	0.01545200	0.00388097	0.00008768	0.00299521	0.03803206	0.03247746	0.00669725	0.14721246	0.02126902	0.00047134	0.01260249	0.00147542
EXP_OM_AG_REG	PRODUCTION	0.56323941	0.20895270	0.01433999	0.05356864	0.00081514	0.00007922	0.05365965	0.00862695	0.00328525	0.00007280	0.00192511	0.02586730	0.03016784	0.00508996	0.13121059	0.02497085	0.00034190	0.00019664	0.00006888
EXP_OM_AG_REG	BULKTRAN	0.14743142	0.05469467	0.00375358	0.01402193	0.00021337	0.00002074	0.01404575	0.00225816	0.00085994	0.00001906	0.00050391	0.00677093	0.00789662	0.00133233	0.03434519	0.00653627	0.00008949	0.00005147	0.00001803
EXP_OM_AG_REG	SUBTRAN	0.03795495	0.01365705	0.00091279	0.00341923	0.00005243	0.00000686	0.00348474	0.00056109	0.00028151	-	0.00012085	0.00167773	0.00266378	-	0.01109413	-	0.00002274	-	-
EXP_OM_AG_REG	DISTPRI	0.14169228	0.08282848	0.00549392	0.01968498	0.00029961	-	0.01987334	0.00319600	-	-	0.00074051	0.00944217	-	-	-	-	0.00013327	-	-
EXP_OM_AG_REG	DISTSEC	0.06822485	0.04477452	0.00383466	0.00964764	-	-	0.00860345	-	-	-	0.00026592	-	-	-	-	-	0.00004946	0.00078982	0.00025938
EXP_OM_AG_REG	ENERGY	0.00120088	0.00032134	0.00003177	0.00011122	0.00000170	0.00000017	0.00011463	0.00001829	0.00000700	0.00000015	0.00000471	0.00006505	0.00007334	0.00001077	0.00035740	0.00007233	0.00000093	0.00000758	0.00000253
EXP_OM_AG_REG	CUSTOMER	0.04025622	0.01444908	0.00583549	0.00176897	0.00048887	0.00011399	0.00055964	0.00013513	0.00034938	0.00002929	0.00000460	0.00008692	0.00046832	0.00010331	0.00022940	0.00006299	0.00000290	0.01333533	0.00223261
EXP_OM_AG_REG	TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
Acct 907-916	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	5,025,154	3,188,254	549,196	166,052	1,936	231	17,428	1,729	461	23	138	922	599	115	207	46	254	1,096,271	1,291
	TOTAL	5,025,154	3,188,254	549,196	166,052	1,936	231	17,428	1,729	461	23	138	922	599	115	207	46	254	1,096,271	1,291
EXP_OM_CUSTSERV	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	CUSTOMER	1.00000000	0.63445897	0.10928934	0.03304416	0.00038535	0.00004588	0.00346819	0.00034407	0.00009175	0.00000459	0.00002753	0.00018350	0.00011928	0.00002294	0.00004129	0.00000918	0.00005046	0.21815663	0.00025690
EXP_OM_CUSTSERV	TOTAL	1.00000000	0.63445897	0.10928934	0.03304416	0.00038535	0.00004588	0.00346819	0.00034407	0.00009175	0.00000459	0.00002753	0.00018350	0.00011928	0.00002294	0.00004129	0.00000918	0.00005046	0.21815663	0.00025690
O&M Expense	PRODUCTION	160,056,499	75,203,233	3,295,647	12,412,812	222,251	23,266	13,440,713	2,616,288	774,262	15,287	469,698	6,507,169	6,895,966	1,514,461	31,654,481	4,876,410	73,068	50,048	11,440
	BULKTRAN	(37,794,816)	(17,765,507)	(777,848)	(2,929,767)	(52,477)	(5,494)	(3,172,961)	(617,873)	(182,755)	(3,607)	(110,875)	(1,536,168)	(1,627,584)	(357,648)	(7,472,055)	(1,150,442)	(17,243)	(11,815)	(2,698)
	SUBTRAN	(9,745,850)	(4,443,620)	(189,483)	(715,651)	(12,918)	(1,821)	(788,566)	(153,789)	(59,930)	-	(26,638)	(381,294)	(549,982)	-	(2,417,770)	-	(4,389)	-	-
	DISTPRI	33,598,642	22,635,178	958,844	3,463,913	62,031	-	3,780,123	735,986	-	-	137,202	1,803,736	-	-	-	-	21,630	-	-
	DISTSEC	13,141,215	9,755,465	533,663	1,353,711	-	-	1,304,872	-	-	-	39,287	-	-	-	-	-	6,401	121,721	26,095
	ENERGY	160,343,876	56,976,826	3,595,023	12,690,692	227,925	24,276	14,140,349	2,731,514	812,764	15,982	565,493	8,059,428	8,255,525	1,577,764	42,462,524	6,953,952	97,461	949,726	206,651
	CUSTOMER	12,164,983	8,561,594	1,427,581	447,317	73,747	18,015	100,078	25,075	44,176	3,276	817	13,454	57,481	16,382	29,500	6,559	659	1,067,365	271,906
	TOTAL	331,764,550	150,923,170	8,843,427	26,723,028	520,560	58,242	28,804,608	5,337,201	1,388,518	30,938	1,074,983	14,466,326	13,031,406	2,750,960	64,256,681	10,686,478	177,587	2,177,044	513,395
EXP_OM	PRODUCTION	0.48244003	0.22667652	0.00993369	0.03741452	0.00066990	0.00007013	0.04051281	0.00788598	0.00233377	0.00004608	0.00141576	0.01961382	0.02078572	0.00456487	0.09541249	0.01469840	0.00022024	0.00015085	0.00003448
EXP_OM	BULKTRAN	(0.11392060)	(0.05354854)	(0.00234458)	(0.00883086)	(0.00015817)	(0.00001656)	(0.00956389)	(0.00186238)	(0.00055086)	(0.00001087)	(0.00033420)	(0.00463030)	(0.00490584)	(0.00107802)	(0.02252216)	(0.00346765)	(0.00005197)	(0.00003561)	(0.00000813)
EXP_OM	SUBTRAN	(0.02937580)	(0.01339390)	(0.00057114)	(0.00215710)	(0.00003894)	(0.00000549)	(0.00237688)	(0.00046355)	(0.00018064)	-	(0.00008029)	(0.00114929)	(0.00165775)	-	(0.00728761)	-	(0.00001323)	-	-
EXP_OM	DISTPRI	0.10127255	0.06822663	0.00289013	0.01044088	0.00018697	-	0.01139399	0.00221840	-	-	0.00041355	0.00543680	-	-	-	-	0.00006520	-	-
EXP_OM	DISTSEC	0.03961006	0.02940479	0.00160856	0.00408034	-	-	0.00393313	-	-	-	0.00011842	-	-	-	-	-	0.00001929	0.00036689	0.00007866
EXP_OM	ENERGY	0.48330624	0.17173874	0.01083607	0.03825210	0.00068701	0.00007317	0.04262164	0.00823329	0.00244982	0.00004817	0.00170450	0.02429261	0.02488369	0.00475568	0.12798994	0.02096050	0.00029376	0.00286265	0.00062289
EXP_OM	CUSTOMER	0.03666752	0.02580623	0.00430299	0.00134830	0.00022229	0.00005430	0.00030165	0.00007558	0.00013315	0.00000987	0.00000246	0.00004055	0.00017326	0.00004938	0.00008892	0.00001977	0.00000199	0.00321724	0.00081957
EXP_OM	TOTAL	1.00000000	0.45491048	0.02665573	0.08054817	0.00156906	0.00017555	0.08682244	0.01608732	0.00418525	0.00009325	0.00324020	0.04360419	0.03927908	0.00829190	0.19368157	0.03221103	0.00053528	0.00656202	0.00154747
O&M Labor	PRODUCTION	9,180,999	4,314,590	188,999	711,859	12,748	1,335	770,875	150,082	44,404	877	26,938	373,212	395,468	86,875	1,815,427	279,595	4,190	2,870	656
	BULKTRAN	398,962	187,492	8,213	30,934	554	58	33,499	6,522	1,930	38	1,171	16,218	17,185	3,775	78,890	12,150	182	125	28
	SUBTRAN	102,877	46,896	2,001	7,556	136	19	8,325	1,623	633	-	281	4,025	5,807	-	25,527	-	46	-	-
	DISTPRI	5,789,083	3,900,651	165,143	596,601	10,686	-	651,137	126,807	-	-	23,633	310,701	-	-	-	-	3,725	-	-
	DISTSEC	2,263,653	1,680,709	91,877	233,064	-	-	224,687	-	-	-	6,764	-	-	-	-	-	1,102	20,960	4,489
	ENERGY	1,195,224	424,713	26,798	94,598	1,699	181	105,404	20,361	6,058	119	4,215	60,076	61,538	11,761	316,521	51,836	726	7,079	1,540
	CUSTOMER	2,366,405	1,671,432	275,151	86,110	12,805	3,115	18,219	4,418	7,630	565	149	2,370	9,929	2,828	5,090	1,131	127	218,472	46,865
	TOTAL	21,297,204	12,226,483	758,182	1,760,722	38,629	4,708	1,812,146	309,812	60,655	1,599	63,151	766,603	489,927	105,238	2,241,455	344,712	10,099	249,507	53,579
LABOR_M	PRODUCTION	0.43108943	0.20258952	0.00887437	0.03342499	0.00059858	0.00006266	0.03619605	0.00704702	0.00208496	0.00004116	0.00126487	0.01752399	0.01856903	0.00407916	0.08524250	0.01312826	0.00019674	0.00013478	0.00003079
LABOR_M	BULKTRAN	0.01873309	0.00880357	0.00038564	0.00145249	0.00002601	0.00000272	0.00157291	0.00030623	0.00009060	0.00000179	0.00005497	0.00076151	0.00080692	0.00017726	0.00370423	0.00057049	0.00000855	0.00000586	0.00000134
LABOR_M	SUBTRAN	0.00483055	0.00220200	0.00009394	0.00035480	0.00000640	0.00000090	0.00039091	0.00007622	0.00002971	-	0.00001321	0.00018901	0.00027267	-	0.00119859	-	0.00000218	-	-
LABOR_M	DISTPRI	0.27182362	0.18315319	0.00775420	0.02801311	0.00050177	-	0.03057384	0.00595416	-	-	0.00110965	0.01458880	-	-	-	-	0.00017490	-	-
LABOR_M	DISTSEC	0.10628873	0.07891689	0.00431405	0.01094339	-	-	0.01055009	-	-	-	0.00031762	-	-	-	-	-	0.00005174	0.00098416	0.00021079
LABOR_M	ENERGY	0.05612117	0.01994219	0.00125828	0.00444180	0.00007978	0.00000850	0.00494919	0.00095604	0.00028447	0.00000559	0.00019793	0.00282084	0.00288947	0.00055223	0.01486209	0.00243392	0.00003411	0.00033241	0.00007233
LABOR_M	CUSTOMER	0.11111342	0.07848128	0.01291958	0.00404327	0.00060125	0.00014626	0.00085544	0.00020742	0.00035828	0.00002653	0.00000698	0.00011130	0.00046619	0.00013278	0.00023901	0.00005311	0.00000596	0.01025827	0.00220051
LABOR_M	TOTAL	1.00000000	0.57408864	0.03560006	0.08267384	0.00181379	0.00022104	0.08508842	0.01454710	0.00284802	0.00007507	0.00296522	0.03599546	0.02300429	0.00494142	0.10524643	0.01618579	0.00047417	0.01171547	0.00251576

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
Production O&M Labor	PRODUCTION	8,609,401	4,045,969	177,232	667,539	11,954	1,251	722,881	140,738	41,639	822	25,261	349,976	370,847	81,466	1,702,401	262,188	3,929	2,692	615
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	1,195,224	424,713	26,798	94,598	1,699	181	105,404	20,361	6,058	119	4,215	60,076	61,538	11,761	316,521	51,836	726	7,079	1,540
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	9,804,625	4,470,682	204,030	762,137	13,653	1,432	828,285	161,099	47,698	941	29,476	410,052	432,385	93,227	2,018,922	314,024	4,656	9,771	2,155
LABOR_PROD	PRODUCTION	0.87809590	0.41265922	0.01807641	0.06808412	0.00121925	0.00012764	0.07372855	0.01435423	0.00424690	0.00008384	0.00257644	0.03569501	0.03782369	0.00830893	0.17363240	0.02674126	0.00040074	0.00027454	0.00006272
LABOR_PROD	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	ENERGY	0.12190410	0.04331760	0.00273318	0.00964831	0.00017328	0.00001846	0.01075043	0.00207668	0.00061792	0.00001215	0.00042993	0.00612731	0.00627640	0.00119952	0.03228283	0.00528685	0.00007410	0.00072204	0.00015711
LABOR_PROD	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	TOTAL	1.00000000	0.45597682	0.02080959	0.07773243	0.00139254	0.00014610	0.08447899	0.01643091	0.00486482	0.00009599	0.00300636	0.04182232	0.04410009	0.00950845	0.20591523	0.03202811	0.00047484	0.00099658	0.00021983
T&D O&M Labor	PRODUCTION	571,598	268,621	11,767	44,320	794	83	47,994	9,344	2,765	55	1,677	23,236	24,621	5,409	113,026	17,407	261	179	41
	BULKTRAN	398,962	187,492	8,213	30,934	554	58	33,499	6,522	1,930	38	1,171	16,218	17,185	3,775	78,890	12,150	182	125	28
	SUBTRAN	102,877	46,896	2,001	7,556	136	19	8,325	1,623	633	-	281	4,025	5,807	-	25,527	-	46	-	-
	DISTPRI	5,789,083	3,900,651	165,143	596,601	10,686	-	651,137	126,807	-	-	23,633	310,701	-	-	-	-	3,725	-	-
	DISTSEC	2,263,653	1,680,709	91,877	233,064	-	-	224,687	-	-	-	6,764	-	-	-	-	-	1,102	20,960	4,489
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	483,528	184,292	73,308	22,500	12,048	3,025	11,136	3,702	7,439	556	89	1,974	9,671	2,778	5,001	1,111	34	98,433	46,430
	TOTAL	9,609,702	6,268,662	352,309	934,974	24,218	3,185	976,778	147,998	12,766	648	33,615	356,154	57,285	11,962	222,444	30,669	5,350	119,696	50,989
LABOR_TD	PRODUCTION	0.05948139	0.02795315	0.00122448	0.00461195	0.00008259	0.00000865	0.00499430	0.00097234	0.00028768	0.00000568	0.00017453	0.00241795	0.00256214	0.00056284	0.01176170	0.00181143	0.00002715	0.00001860	0.00000425
LABOR_TD	BULKTRAN	0.04151663	0.01951065	0.00085466	0.00321904	0.00005765	0.00000603	0.00348591	0.00067867	0.00020079	0.00000396	0.00012181	0.00168767	0.00178832	0.00039285	0.00820939	0.00126433	0.00001895	0.00001298	0.00000297
LABOR_TD	SUBTRAN	0.01070555	0.00488012	0.00020819	0.00078631	0.00001419	0.00000200	0.00086634	0.00016892	0.00006585	-	0.00002927	0.00041890	0.00060429	-	0.00265635	-	0.00000482	-	-
LABOR_TD	DISTPRI	0.60242066	0.40590757	0.01718500	0.06208319	0.00111203	-	0.06775833	0.01319572	-	-	0.00245924	0.03233198	-	-	-	-	0.00038761	-	-
LABOR_TD	DISTSEC	0.23555910	0.17489711	0.00956089	0.02425294	-	-	0.02338130	-	-	-	0.00070392	-	-	-	-	-	0.00011466	0.00218112	0.00046716
LABOR_TD	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_TD	CUSTOMER	0.05031667	0.01917775	0.00762856	0.00234140	0.00125375	0.00031477	0.00115880	0.00038519	0.00077414	0.00005782	0.00000928	0.00020544	0.00100638	0.00028912	0.00052042	0.00011565	0.00000352	0.01024306	0.00483161
LABOR_TD	TOTAL	1.00000000	0.65232635	0.03666177	0.09729483	0.00252020	0.00033145	0.10164498	0.01540085	0.00132846	0.00006747	0.00349805	0.03706193	0.00596113	0.00124481	0.02314786	0.00319141	0.00055671	0.01245575	0.00530598
Other Revenues	PRODUCTION	1,241,067	908,842	61,716	145,690	1,723	545	52,266	7,963	3,398	232	2,477	12,428	23,555	7,318	12,274	-	-	638	-
	BULKTRAN	(328,019)	(197,271)	(748)	(8,025)	(323)	(17)	(21,725)	(5,131)	(1,031)	31	(760)	(11,828)	(10,712)	(3,461)	(57,892)	(8,898)	(133)	(71)	(21)
	SUBTRAN	(84,081)	(49,349)	(179)	(1,952)	(79)	(6)	(5,397)	(1,277)	(338)	-	(183)	(2,936)	(3,618)	-	(18,732)	-	(34)	-	-
	DISTPRI	4,283,560	2,940,080	140,688	459,390	7,720	-	434,739	82,772	-	-	16,174	199,686	-	-	-	-	2,310	-	-
	DISTSEC	2,872,880	2,137,891	127,779	302,637	-	-	265,433	-	-	-	8,115	-	-	-	-	-	1,243	24,717	5,064
	ENERGY	1,335,164	895,598	68,282	154,198	2,224	702	67,263	11,306	4,263	292	3,629	23,120	35,057	10,665	49,424	4,966	70	3,955	148
	CUSTOMER	434,110	236,818	70,785	16,840	4,174	1,834	3,583	964	2,197	325	31	490	2,661	773	1,132	245	12	83,921	7,326
	TOTAL	9,754,682	6,872,609	468,323	1,068,778	15,439	3,059	796,161	96,597	8,489	880	29,484	220,960	46,943	15,295	(13,794)	(3,686)	3,467	113,160	12,516
REV_OTHER	PRODUCTION	0.12722787	0.09316980	0.00632686	0.01493540	0.00017664	0.00005592	0.00535807	0.00081634	0.00034833	0.00002379	0.00025395	0.00127407	0.00241475	0.00075025	0.00125827	-	-	0.00006543	-
REV_OTHER	BULKTRAN	(0.03362678)	(0.02022324)	(0.00007671)	(0.00082270)	(0.00003312)	(0.00000177)	(0.00222718)	(0.00052604)	(0.00010568)	0.00000321	(0.00007791)	(0.00121259)	(0.00109811)	(0.00035484)	(0.00593481)	(0.00091218)	(0.00001367)	(0.00000730)	(0.00000214)
REV_OTHER	SUBTRAN	(0.00861952)	(0.00505903)	(0.00001837)	(0.00020014)	(0.00000814)	(0.00000058)	(0.00055331)	(0.00013092)	(0.00003463)	-	(0.00001871)	(0.00030095)	(0.00037091)	-	(0.00192033)	-	(0.00000348)	-	-
REV_OTHER	DISTPRI	0.43912859	0.30140192	0.01442260	0.04709433	0.00079146	-	0.04456725	0.00848538	-	-	0.00165807	0.02047073	-	-	-	-	0.00023684	-	-
REV_OTHER	DISTSEC	0.29451295	0.21916568	0.01309927	0.03102481	-	-	0.02721080	-	-	-	0.00083196	-	-	-	-	-	0.00012742	0.00253387	0.00051915
REV_OTHER	ENERGY	0.13687416	0.09181215	0.00699994	0.01580760	0.00022800	0.00007198	0.00689544	0.00115900	0.00043702	0.00002998	0.00037201	0.00237018	0.00359388	0.00109336	0.00506672	0.00050914	0.00000714	0.00040550	0.00001513
REV_OTHER	CUSTOMER	0.04450272	0.02427736	0.00725649	0.00172637	0.00042790	0.00018801	0.00036732	0.00009886	0.00022518	0.00003328	0.00000318	0.00005027	0.00027276	0.00007924	0.00011600	0.00002516	0.00000123	0.00860313	0.00075098
REV_OTHER	TOTAL	1.00000000	0.70454464	0.04801008	0.10956566	0.00158274	0.00031356	0.08161840	0.00990262	0.00087022	0.00009026	0.00302255	0.02265171	0.00481237	0.00156801	(0.00141414)	(0.00037788)	0.00035547	0.01160062	0.00128312
Total Revenues	PRODUCTION	206,469,696	85,237,287	5,534,336	20,401,815	294,412	30,535	20,400,692	4,050,235	1,075,527	20,118	652,807	8,788,094	10,157,524	1,890,903	40,835,070	6,432,175	117,360	455,149	95,656
	BULKTRAN	(1,506,655)	(5,394,304)	414,026	1,850,027	12,340	1,208	984,217	(172,996)	113,226	5,164	22,763	20,365	751,935	(171,860)	(428,965)	467,708	9,271	6,784	2,435
	SUBTRAN	(423,227)	(1,349,829)	101,102	452,924	3,054	403	245,302	(43,018)	37,206	-	5,485	5,204	254,696	-	(138,122)	-	2,365	-	-
	DISTPRI	81,999,594	48,077,773	3,153,997	11,808,905	175,139	-	11,501,599	2,031,841	-	-	382,805	4,796,436	-	-	-	-	71,100	-	-
	DISTSEC	35,688,893	23,108,565	2,028,640	5,348,346	-	-	4,555,335	-	-	-	125,318	-	-	-	-	-	24,319	389,155	109,215
	ENERGY	223,430,251	74,993,065	5,243,691	18,587,454	318,097	34,031	20,550,759	4,433,892	1,104,983	24,653	783,381	11,459,118	11,902,924	2,316,538	60,646,275	9,481,676	141,674	1,116,956	291,081
	CUSTOMER	24,689,205	12,340,625	3,604,376	1,151,023	236,579	58,574	295,668	71,852	167,679	17,829	2,172	37,386	216,260	39,295	87,000	22,945	1,662	5,401,441	936,839
	TOTAL	570,347,757	237,013,183	20,080,167	59,600,494	1,039,622	124,751	58,533,572	10,371,807	2,498,622	67,765	1,974,731	25,106,602	23,283,340	4,074,876	101,001,259	16,404,504	367,752	7,369,485	1,435,226
REV	PRODUCTION	0.36200668	0.14944792	0.00970344	0.03577083	0.00051620	0.00005354	0.03576887	0.00710134	0.00188574	0.00003527	0.00114458	0.01540831	0.01780935	0.00331535	0.07159679	0.01127764	0.00020577	0.00079802	0.00016771
REV	BULKTRAN	(0.00264164)	(0.00945792)	0.00072592	0.00324368	0.00002164	0.00000212	0.00172564	(0.00030332)	0.00019852	0.00000905	0.00003991	0.00003571	0.00131838	(0.00030133)	(0.00075211)	0.00082004	0.00001625	0.00001189	0.00000427
REV	SUBTRAN	(0.00074205)	(0.00236668)	0.00017726	0.00079412	0.00000535	0.00000071	0.00043009	(0.00007542)	0.00006523	-	0.00000962	0.00000912	0.00044656	-	(0.00024217)	-	0.00000415	-	-
REV	DISTPRI	0.14377122	0.08429554	0.00552995	0.02070475	0.00030707	-	0.02016594	0.00356246	-	-	0.00067118	0.00840967	-	-	-	-	0.00012466	-	-
REV	DISTSEC	0.06257392	0.04051662	0.00355685	0.00937734	-	-	0.00798694	-	-	-	0.00021972	-	-	-	-	-	0.00004264	0.00068231	0.00019149
REV	ENERGY	0.39174389	0.13148656	0.00919385	0.03258969	0.00055773	0.00005967	0.03603198	0.00777402	0.00193738	0.00004322	0.00137351	0.02009146	0.02086959	0.00406162	0.10633210	0.01662438	0.00024840	0.00195838	0.00051036
REV	CUSTOMER	0.04328799	0.02163702	0.00631961	0.00201811	0.00041480	0.00010270	0.00051840	0.00012598	0.00029399	0.00003126	0.00000381	0.00006555	0.00037917	0.00006890	0.00015254	0.00004023	0.00000291	0.00947043	0.00164258
REV	TOTAL	1.00000000	0.41555907	0.03520688	0.10449852	0.00182279	0.00021873	0.10262786	0.01818506	0.00438087	0.00011881	0.00346233	0.04401981	0.04082306	0.00714455	0.17708715	0.02876228	0.00064478	0.01292104	0.00251641

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
PSC MAINT FEE	PRODUCTION	977,071	410,055	33,418	99,879	1,828	216	98,040	14,456	4,673	119	3,484	42,903	40,324	6,386	173,173	30,917	626	14,051	2,522
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	977,071	410,055	33,418	99,879	1,828	216	98,040	14,456	4,673	119	3,484	42,903	40,324	6,386	173,173	30,917	626	14,051	2,522
Intermediate Step	PRODUCTION	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
RATEBASE	PRODUCTION	0.29647495	0.13645765	0.00593330	0.02287178	0.00021891	0.00001587	0.02541521	0.00489317	0.00138788	0.00001144	0.00090041	0.01227820	0.01294035	0.00270029	0.06086557	0.00932926	0.00014040	0.00009333	0.00002190
	BULKTRAN	0.20871639	0.09738921	0.00425051	0.01614675	0.00023985	0.00002326	0.01764937	0.00339498	0.00100106	0.00001551	0.00062139	0.00854225	0.00903580	0.00194131	0.04183379	0.00645353	0.00009657	0.00006611	0.00001513
	SUBTRAN	0.05393653	0.02439967	0.00103713	0.00395057	0.00005918	0.00000773	0.00439334	0.00084639	0.00032881	-	0.00014952	0.00212367	0.00305821	-	0.01355769	-	0.00002462	-	-
	DISTPRI	0.22143212	0.14874077	0.00628096	0.02288350	0.00033991	-	0.02521407	0.00488521	-	-	0.00092011	0.01202245	-	-	-	-	0.00014513	-	-
	DISTSEC	0.10813435	0.08010723	0.00436725	0.01117275	-	-	0.01087430	-	-	-	0.00032924	-	-	-	-	-	0.00005366	0.00101147	0.00021845
	ENERGY	0.05420183	0.01913129	0.00121956	0.00430595	0.00007569	0.00000806	0.00481065	0.00098526	0.00026723	0.00000538	0.00018898	0.00273100	0.00279133	0.00054646	0.01443761	0.00230028	0.00003303	0.00029539	0.00006867
	CUSTOMER	0.05710383	0.02634330	0.00669311	0.00206418	0.00054955	0.00012783	0.00070697	0.00020507	0.00040599	0.00002387	0.00000570	0.00010996	0.00053635	0.00015103	0.00027979	0.00006211	0.00000317	0.01695662	0.00187923
	TOTAL	1.00000000	0.53256912	0.02978183	0.08339548	0.00148310	0.00018275	0.08906391	0.01521009	0.00339097	0.00005620	0.00311536	0.03780752	0.02836205	0.00533909	0.13097445	0.01814519	0.00049657	0.01842292	0.00220339
EXP_OTHTAX_PSC	PRODUCTION	0.31439089	0.10753205	0.00681395	0.02803525	0.00027619	0.00001919	0.02863329	0.00475984	0.00195766	0.00002470	0.00103055	0.01426005	0.01882963	0.00330583	0.08236427	0.01626881	0.00018114	0.00007285	0.00002566
EXP_OTHTAX_PSC	BULKTRAN	0.22059642	0.07674515	0.00488140	0.01979200	0.00030260	0.00002812	0.01988414	0.00330247	0.00141202	0.00003347	0.00071120	0.00992106	0.01314808	0.00237664	0.05661016	0.01125398	0.00012460	0.00005160	0.00001773
EXP_OTHTAX_PSC	SUBTRAN	0.05704768	0.01922755	0.00119107	0.00484243	0.00007466	0.00000934	0.00494963	0.00082333	0.00046380	-	0.00017113	0.00246645	0.00445004	-	0.01834648	-	0.00003177	-	-
EXP_OTHTAX_PSC	DISTPRI	0.20126525	0.11721146	0.00721321	0.02804961	0.00042884	-	0.02840668	0.00475209	-	-	0.00105310	0.01396302	-	-	-	-	0.00018724	-	-
EXP_OTHTAX_PSC	DISTSEC	0.09557978	0.06312651	0.00501546	0.01369508	-	-	0.01225120	-	-	-	0.00037682	-	-	-	-	-	0.00006923	0.00078955	0.00025594
EXP_OTHTAX_PSC	ENERGY	0.06064753	0.01507594	0.00140057	0.00527805	0.00009550	0.00000974	0.00541978	0.00095841	0.00037693	0.00001161	0.00021629	0.00317181	0.00406170	0.00066900	0.01953720	0.00401134	0.00004262	0.00023058	0.00008046
EXP_OTHTAX_PSC	CUSTOMER	0.05047244	0.02075918	0.00768654	0.00253019	0.00069332	0.00015457	0.00079648	0.00019948	0.00057267	0.00005152	0.00000652	0.00012770	0.00078045	0.00018490	0.00037861	0.00010832	0.00000408	0.01323625	0.00220165
EXP_OTHTAX_PSC	TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
AFUDC Offset	PRODUCTION	3,128,143	1,470,064	64,396	242,544	4,343	455	262,652	51,136	15,129	299	9,178	127,160	134,744	29,600	618,551	95,263	1,428	978	223
	BULKTRAN	1,514,512	711,742	31,178	117,429	2,103	220	127,165	24,758	7,325	145	4,444	61,566	65,237	14,331	299,476	46,122	691	474	108
	SUBTRAN	390,535	178,025	7,595	28,684	518	73	31,604	6,162	2,402	-	1,068	15,281	22,044	-	96,903	-	176	-	-
	DISTPRI	269,200	181,385	7,679	27,743	497	-	30,279	5,897	-	-	1,099	14,448	-	-	-	-	173	-	-
	DISTSEC	132,132	98,105	5,363	13,604	-	-	13,115	-	-	-	395	-	-	-	-	-	64	1,223	262
	ENERGY	1,836	652	41	145	3	0	162	31	9	0	6	92	95	18	486	80	1	11	2
	CUSTOMER	69,130	31,518	8,144	2,489	811	204	853	249	501	37	7	133	652	187	337	75	4	20,674	2,255
	TOTAL	5,505,487	2,671,491	124,396	432,639	8,275	952	465,829	88,233	25,367	481	16,197	218,681	222,771	44,136	1,015,752	141,540	2,537	23,360	2,851
AFUDC_OFF	PRODUCTION	0.56818639	0.26701793	0.01169664	0.04405495	0.00078894	0.00008259	0.04770727	0.00928814	0.00274803	0.00005425	0.00166713	0.02309704	0.02447444	0.00537643	0.11235170	0.01730337	0.00025931	0.00017765	0.00004058
AFUDC_OFF	BULKTRAN	0.27509146	0.12927862	0.00566301	0.02132952	0.00038197	0.00003999	0.02309781	0.00449692	0.00133048	0.00002627	0.00080715	0.01118260	0.01184947	0.00260304	0.05439587	0.00837755	0.00012554	0.00008601	0.00001965
AFUDC_OFF	SUBTRAN	0.07093553	0.03233593	0.00137950	0.00521012	0.00009403	0.00001325	0.00574042	0.00111929	0.00043630	-	0.00019392	0.00277564	0.00400409	-	0.01760111	-	0.00003196	-	-
AFUDC_OFF	DISTPRI	0.04889661	0.03294625	0.00139485	0.00503910	0.00009026	-	0.00549973	0.00107106	-	-	0.00019961	0.00262429	-	-	-	-	0.00003146	-	-
AFUDC_OFF	DISTSEC	0.02400002	0.01781945	0.00097411	0.00247102	-	-	0.00238221	-	-	-	0.00007172	-	-	-	-	-	0.00001168	0.00022222	0.00004760
AFUDC_OFF	ENERGY	0.00033351	0.00011851	0.00000748	0.00002640	0.00000047	0.00000005	0.00002941	0.00000568	0.00000169	0.00000003	0.00000118	0.00001676	0.00001717	0.00000328	0.00008832	0.00001446	0.00000020	0.00000198	0.00000043
AFUDC_OFF	CUSTOMER	0.01255648	0.00572481	0.00147931	0.00045209	0.00014738	0.00003702	0.00015488	0.00004531	0.00009104	0.00000680	0.00000124	0.00002417	0.00011835	0.00003399	0.00006119	0.00001360	0.00000068	0.00375511	0.00040951
AFUDC_OFF	TOTAL	1.00000000	0.48524151	0.02259490	0.07858320	0.00150305	0.00017290	0.08461173	0.01602639	0.00460753	0.00008735	0.00294194	0.03972049	0.04046352	0.00801674	0.18449819	0.02570898	0.00046084	0.00424297	0.00051777

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL	
RBASE		553,292,077	232,204,424	18,923,805	56,558,951	1,035,270	122,264	55,517,995	8,186,301	2,646,442	67,113	1,972,823	24,295,105	22,834,308	3,616,522	98,063,673	17,507,511	354,484	7,956,803	1,428,283	521,694,557
Initial RSALE		553,292,078	232,204,424	18,923,805	56,558,951	1,035,270	122,264	55,517,995	8,186,301	2,646,442	67,113	1,972,823	24,295,105	22,834,308	3,616,522	98,063,673	17,507,511	354,484	7,956,803	1,428,283	539,556,553
Initial Other Revenue		9,607,185	5,347,943	555,565	1,312,753	-23,599	-845	1,419,480	1,911,204	-204,043	901	-48,657	228,741	-98,219	344,061	1,060,486	-1,350,369	3,599	-813,148	-38,667	10,124,028
Initial Total Expense		485,021,545	211,916,612	15,158,967	44,953,836	827,270	97,347	46,331,866	8,941,352	1,955,507	50,696	1,610,554	21,307,132	18,939,638	3,750,717	88,914,524	13,998,042	287,683	4,974,931	1,004,869	549,680,581
Net Operating Income		85,578,115	25,635,756	4,320,404	12,917,868	184,400	24,072	10,605,610	1,156,153	486,892	17,318	313,612	3,216,714	3,796,450	209,866	10,209,635	2,159,100	70,400	2,168,724	384,747	
RATEBASE	PRODUCTION	0.29647495	0.13645765	0.00593330	0.02287178	0.00021891	0.00001587	0.02541521	0.00489317	0.00138788	0.00001144	0.00090041	0.01227820	0.01294035	0.00270029	0.06086557	0.00932926	0.00014040	0.00009333	0.00002190	
RATEBASE	BULKTRAN	0.20871639	0.09738921	0.00425051	0.01614675	0.00023985	0.00002326	0.01764937	0.00339498	0.00100106	0.00001551	0.00062139	0.00854225	0.00903580	0.00194131	0.04183379	0.00645353	0.00009657	0.00006611	0.00001513	
RATEBASE	SUBTRAN	0.05393653	0.02439967	0.00103713	0.00395057	0.00005918	0.00000773	0.00439334	0.00084639	0.00032881	-	0.00014952	0.00212367	0.00305821	-	0.01355769	-	0.00002462	-	-	
RATEBASE	DISTPRI	0.22143212	0.14874077	0.00628096	0.02288350	0.00033991	-	0.02521407	0.00488521	-	-	0.00092011	0.01202245	-	-	-	-	0.00014513	-	-	
RATEBASE	DISTSEC	0.10813435	0.08010723	0.00436725	0.01117275	-	-	0.01087430	-	-	-	0.00032924	-	-	-	-	-	0.00005366	0.00101147	0.00021845	
RATEBASE	ENERGY	0.05420183	0.01913129	0.00121956	0.00430595	0.00007569	0.00000806	0.00481065	0.00098526	0.00026723	0.00000538	0.00018898	0.00273100	0.00279133	0.00054646	0.01443761	0.00230028	0.00003303	0.00029539	0.00006867	
RATEBASE	CUSTOMER	0.05710383	0.02634330	0.00669311	0.00206418	0.00054955	0.00012783	0.00070697	0.00020507	0.00040599	0.00002387	0.00000570	0.00010996	0.00053635	0.00015103	0.00027979	0.00006211	0.00000317	0.01695662	0.00187923	
RATEBASE	TOTAL	1.00000000	0.53256912	0.02978183	0.08339548	0.00148310	0.00018275	0.08906391	0.01521009	0.00339097	0.00005620	0.00311536	0.03780752	0.02836205	0.00533909	0.13097445	0.01814519	0.00049657	0.01842292	0.00220339	
NOI - Functionalized	PRODUCTION	23,465,481	6,568,527	860,735	3,542,814	27,219	2,091	3,026,408	371,941	199,279	3,526	90,641	1,044,646	1,732,153	106,142	4,744,554	1,110,091	19,905	10,987	3,824	
	BULKTRAN	16,474,955	4,687,929	616,615	2,501,114	29,822	3,064	2,101,663	258,060	143,736	4,779	62,554	726,786	1,209,502	76,308	3,261,001	767,907	13,691	7,782	2,642	
	SUBTRAN	4,245,403	1,174,503	150,455	611,938	7,358	1,018	523,153	64,336	47,213	-	15,052	180,684	409,362	-	1,056,840	-	3,490	-	-	
	DISTPRI	16,167,727	7,159,788	911,169	3,544,628	42,263	-	3,002,457	371,336	-	-	92,625	1,022,886	-	-	-	-	20,575	-	-	
	DISTSEC	7,713,101	3,856,043	633,550	1,730,647	-	-	1,294,896	-	-	-	33,143	-	-	-	-	-	7,607	119,069	38,146	
	ENERGY	4,560,137	920,904	176,920	666,987	9,411	1,062	572,846	74,892	38,369	1,657	19,024	232,357	373,639	21,480	1,125,431	273,711	4,683	34,773	11,992	
	CUSTOMER	5,250,913	1,268,062	970,959	319,740	68,328	16,838	84,185	15,588	58,295	7,355	573	9,355	71,794	5,937	21,810	7,391	449	1,996,112	328,143	
	TOTAL	77,877,718	25,635,756	4,320,404	12,917,868	184,400	24,072	10,605,610	1,156,153	486,892	17,318	313,612	3,216,714	3,796,450	209,866	10,209,635	2,159,100	70,400	2,168,724	384,747	
Total Expenses	PRODUCTION	171,454,311	75,192,223	4,061,514	15,106,694	238,536	25,002	15,754,423	3,400,697	819,755	16,821	510,794	7,152,876	7,877,768	1,670,368	34,213,234	5,074,681	87,658	206,399	44,870	
	BULKTRAN	(18,118,815)	(10,219,437)	(202,590)	(651,087)	(17,482)	(1,856)	(1,117,446)	(431,056)	(30,510)	385	(39,790)	(706,421)	(457,567)	(248,168)	(3,689,965)	(300,199)	(4,420)	(998)	(207)	
	SUBTRAN	(4,702,964)	(2,558,665)	(49,353)	(159,015)	(4,304)	(615)	(277,851)	(107,354)	(10,006)	-	(9,567)	(175,480)	(154,666)	-	(1,194,962)	-	(1,125)	-	-	
	DISTPRI	67,167,810	42,206,860	2,246,944	8,279,147	133,143	-	8,515,370	1,663,666	-	-	290,769	3,781,293	-	-	-	-	50,618	-	-	
	DISTSEC	28,600,740	19,859,105	1,397,985	3,625,041	-	-	3,267,517	-	-	-	92,388	-	-	-	-	-	16,747	270,746	71,210	
	ENERGY	220,826,321	76,028,368	5,066,772	17,920,468	308,686	32,970	19,977,913	4,359,000	1,066,614	22,996	764,357	11,226,761	11,529,286	2,295,058	59,520,844	9,207,966	136,991	1,082,182	279,089	
	CUSTOMER	19,794,141	11,408,157	2,637,696	832,589	168,690	41,846	211,940	56,399	109,656	10,494	1,603	28,102	144,819	33,460	65,373	15,594	1,216	3,416,602	609,906	
	TOTAL	485,021,545	211,916,612	15,158,967	44,953,836	827,270	97,347	46,331,866	8,941,352	1,955,507	50,696	1,610,554	21,307,132	18,939,638	3,750,717	88,914,524	13,998,042	287,683	4,974,931	1,004,869	
Total Revenue	PRODUCTION	194,919,792	81,760,751	4,922,249	18,649,508	265,755	27,092	18,780,831	3,772,638	1,019,033	20,347	601,436	8,197,522	9,609,920	1,776,510	38,957,788	6,184,772	107,562	217,385	48,694	
	BULKTRAN	(1,643,859)	(5,531,508)	414,026	1,850,027	12,340	1,208	984,217	(172,996)	113,226	5,164	22,763	20,365	751,935	(171,860)	(428,965)	467,708	9,271	6,784	2,435	
	SUBTRAN	(457,561)	(1,384,162)	101,102	452,924	3,054	403	245,302	(43,018)	37,206	-	5,485	5,204	254,696	-	(138,122)	-	2,365	-	-	
	DISTPRI	83,335,537	49,366,648	3,158,113	11,823,775	175,406	-	11,517,827	2,035,001	-	-	383,394	4,804,180	-	-	-	-	71,193	-	-	
	DISTSEC	36,313,841	23,715,148	2,031,535	5,355,688	-	-	4,562,413	-	-	-	125,531	-	-	-	-	-	24,354	389,816	109,356	
	ENERGY	225,386,458	76,949,272	5,243,691	18,587,454	318,097	34,031	20,550,759	4,433,892	1,104,983	24,653	783,381	11,459,118	11,902,924	2,316,538	60,646,275	9,481,676	141,674	1,116,956	291,081	
	CUSTOMER	25,045,055	12,676,218	3,608,656	1,152,329	237,018	58,684	296,125	71,987	167,950	17,849	2,176	37,457	216,613	39,396	87,183	22,985	1,664	5,412,714	938,049	
	0 TOTAL	562,899,263	237,552,368	19,479,370	57,871,704	1,011,671	121,419	56,937,475	10,097,505	2,442,399	68,014	1,924,166	24,523,846	22,736,089	3,960,583	99,124,159	16,157,142	358,083	7,143,655	1,389,616	
Total Other Revenue	PRODUCTION	1,241,067	908,842	61,716	145,690	1,723	545	52,266	7,963	3,398	232	2,477	12,428	23,555	7,318	12,274	-	-	638	-	
	BULKTRAN	(328,019)	(197,271)	(748)	(8,025)	(323)	(17)	(21,725)	(5,131)	(1,031)	31	(760)	(11,828)	(10,712)	(3,461)	(57,892)	(8,898)	(133)	(71)	(21)	
	SUBTRAN	(84,081)	(49,349)	(179)	(1,952)	(79)	(6)	(5,397)	(1,277)	(338)	-	(183)	(2,936)	(3,618)	-	(18,732)	-	(34)	-	-	
	DISTPRI	4,427,847	3,037,300	144,804	474,260	7,987	-	450,968	85,933	-	-	16,763	207,429	-	-	-	-	2,403	-	-	
	DISTSEC	2,944,193	2,190,839	130,674	309,979	-	-	272,511	-	-	-	8,329	-	-	-	-	-	1,278	25,377	5,206	
	ENERGY	1,335,164	895,598	68,282	154,198	2,224	702	67,263	11,306	4,263	292	3,629	23,120	35,057	10,665	49,424	4,966	70	3,955	148	
	CUSTOMER	470,413	252,865	75,065	18,146	4,613	1,944	4,040	1,099	2,468	345	35	562	3,013	874	1,314	286	14	95,194	8,535	
	TOTAL	10,006,585	7,038,824	479,614	1,092,296	16,144	3,169	819,926	99,892	8,760	901	30,290	228,776	47,296	15,397	(13,612)	(3,646)	3,597	125,094	13,868	
Firm Sales Revenue	PRODUCTION	193,678,725	80,851,909	4,860,532	18,503,817	264,032	26,547	18,728,565	3,764,675	1,015,636	20,115	598,958	8,185,094	9,586,365	1,769,191	38,945,514	6,184,772	107,562	216,747	48,694	
	BULKTRAN	(1,315,841)	(5,334,237)	414,774	1,858,052	12,663	1,225	1,005,943	(167,864)	114,257	5,133	23,523	32,193	762,647	(168,399)	(371,073)	476,606	9,404	6,855	2,456	
	SUBTRAN	(373,480)	(1,334,813)	101,281	454,876	3,134	409	250,700	(41,740)	37,544	-	5,668	8,140	258,314	-	(119,390)	-	2,399	-	-	
	DISTPRI	78,907,690	46,329,349	3,013,309	11,349,515	167,419	-	11,066,859	1,949,069	-	-	366,631	4,596,750	-	-	-	-	68,790	-	-	
	DISTSEC	33,369,648	21,524,309	1,900,861	5,045,708	-	-	4,289,902	-	-	-	117,203	-	-	-	-	-	23,076	364,438	104,150	
	ENERGY	224,051,294	76,053,674	5,175,409	18,433,256	315,873	33,329	20,483,496	4,422,587	1,100,720	24,361	779,752	11,435,998	11,867,867	2,305,872	60,596,851	9,476,710	141,604	1,113,000	290,933	
	CUSTOMER	24,574,641	12,423,353	3,533,591	1,134,182	232,405	56,740	292,085	70,888	165,482	17,504	2,141	36,895	213,599	38,522	85,869	22,699	1,650	5,317,520	929,514	
	TOTAL	552,892,678	230,513,544	18,999,757	56,779,408	995,526	118,250	56,117,549	9,997,613	2,433,639	67,113	1,893,876	24,295,070	22,688,793	3,945,186	99,137,771	16,160,788	354,486	7,018,561	1,375,748	
RSALE	PRODUCTION	0.35030076	0.14623436	0.00879110	0.03346729	0.00047755	0.00004801	0.03387378	0.00680905	0.00183695	0.00003638	0.00108332	0.01480413	0.01733856	0.00319988	0.07043955	0.01118621	0.00019454	0.00039202	0.00008807	
RSALE	BULKTRAN	(0.00237992)	(0.00964787)	0.00075019	0.00336060	0.00002290	0.00000222	0.00181942	(0.00030361)	0.00020665	0.00000928	0.00004255	0.00005823	0.00137938	(0.00030458)	(0.00067115)	0.00086202	0.00001701	0.00001240	0.00000444	
RSALE	SUBTRAN	(0.00067550)	(0.00241423)	0.00018318	0.00082272	0.00000567	0.00000074	0.00045343	(0.00007549)	0.00006790	-	0.00001025	0.00001472	0.00046720	-	(0.00021594)	-	0.00000434	-	-	
RSALE	DISTPRI	0.14271792	0.08379447	0.00545008	0.02052752	0.00030281	-	0.02001629	0.00352522	-	-	0.00066311	0.00831400	-	-	-	-	0.00012442	-	-	
RSALE	DISTSEC	0.06035466	0.03893036	0.00343803	0.00912602	-	-	0.00775901	-	-	-	0.00021198	-	-	-	-	-	0.00004174	0.00065915	0.00018837	
RSALE	ENERGY	0.40523469	0.13755594	0.00936060	0.03333966	0.00057131	0.00006028	0.03704787	0.00799900	0.00199084	0.00004406	0.00141031	0.02068394	0.02146505	0.00417056	0.10959966	0.01714023	0.00025611	0.00201305	0.00052620	
RSALE	CUSTOMER	0.04444740	0.02246974	0.00639110	0.00205136	0.00042034	0.00010262	0.00052828	0.00012821	0.00029930	0.00003166	0.00000387	0.00006673	0.00038633	0.00006967	0.00015531	0.00004106	0.00000298	0.00961764	0.00168118	
RSALE	TOTAL	1.00000000	0.41692276	0.03436428	0.10269517	0.00180058	0.00021388	0.10149809	0.01808238	0.00440165	0.00012139	0.00342540	0.04394175	0.04103652	0.00713554	0.17930744	0.02922952	0.00064115	0.01269426	0.00248827	

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
REVENUES		553,292,077	232,204,424	18,923,805	56,558,951	1,035,270	122,264	55,517,995	8,186,301	2,646,442	67,113	1,972,823	24,295,105	22,834,308	3,616,522	98,063,673	17,507,511	354,484	7,956,803	1,428,283
REVSALES	PRODUCTION	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
REVSALES	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVSALES	TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
O&M Expense w/ Adj	PRODUCTION	111,487,020	51,119,133	2,335,813	8,794,947	146,160	15,402	9,622,625	2,371,320	473,700	10,757	309,782	4,577,408	4,805,882	1,173,293	22,585,332	3,064,325	51,420	22,354	7,367
	BULKTRAN	-37,803,272	-17,592,695	-782,645	-2,947,224	-50,145	-5,275	-3,216,175	-744,274	-166,181	-3,610	-106,129	-1,538,026	-1,618,381	-383,745	-7,555,578	-1,064,615	-17,259	-8,781	-2,534
	SUBTRAN	-9,767,426	-4,400,393	-190,651	-719,916	-12,344	-1,748	-799,307	-185,251	-54,495	0	-25,497	-381,756	-546,874	0	-2,444,801	0	-4,393	0	0
	DISTPRI	38,520,325	25,523,518	1,123,359	4,057,572	69,504	0	4,455,861	1,007,705	0	0	153,987	2,103,587	0	0	0	0	25,232	0	0
	DISTSEC	14,983,437	11,025,772	628,011	1,592,781	0	0	1,544,895	0	0	0	44,296	0	0	0	0	0	7,500	111,189	28,993
	ENERGY	219,883,154	76,989,049	4,974,258	17,556,944	303,780	32,463	19,668,804	4,320,335	1,045,839	22,032	754,676	11,109,972	11,325,154	2,287,792	58,959,799	9,061,502	134,351	1,064,189	272,214
	CUSTOMER	11,349,709	8,158,007	1,397,349	437,914	66,148	16,214	97,044	28,834	37,546	3,085	747	12,745	53,749	16,582	28,060	5,682	642	750,152	239,209
	TOTAL	348,652,947	150,822,391	9,485,494	28,773,018	523,104	57,056	31,373,746	6,798,669	1,336,409	32,265	1,131,861	15,883,930	14,019,530	3,093,922	71,572,812	11,066,894	197,493	1,939,103	545,249
EXP_OM	PRODUCTION	0.31976503	0.14661896	0.00669954	0.02522551	0.00041921	0.00004417	0.02759944	0.00680138	0.00135866	0.00003085	0.00088851	0.01312884	0.01378414	0.00336522	0.06477884	0.00878904	0.00014748	0.00006411	0.00002113
EXP_OM	BULKTRAN	(0.10842665)	(0.05045905)	(0.00224477)	(0.00845317)	(0.00014382)	(0.00001513)	(0.00922458)	(0.00213471)	(0.00047664)	(0.00001035)	(0.00030440)	(0.00441134)	(0.00464181)	(0.00110065)	(0.02167077)	(0.00305351)	(0.00004950)	(0.00002519)	(0.00000727)
EXP_OM	SUBTRAN	(0.02801475)	(0.01262113)	(0.00054682)	(0.00206485)	(0.00003540)	(0.00000501)	(0.00229256)	(0.00053133)	(0.00015630)	-	(0.00007313)	(0.00109494)	(0.00156853)	-	(0.00701213)	-	(0.00001260)	-	-
EXP_OM	DISTPRI	0.11048329	0.07320609	0.00322200	0.01163785	0.00019935	-	0.01278022	0.00289028	-	-	0.00044166	0.00603347	-	-	-	-	0.00007237	-	-
EXP_OM	DISTSEC	0.04297522	0.03162392	0.00180125	0.00456839	-	-	0.00443104	-	-	-	0.00012705	-	-	-	-	-	0.00002151	0.00031891	0.00008316
EXP_OM	ENERGY	0.63066484	0.22081858	0.01426708	0.05035651	0.00087130	0.00009311	0.05641370	0.01239151	0.00299966	0.00006319	0.00216455	0.03186542	0.03248260	0.00656180	0.16910742	0.02599003	0.00038534	0.00305229	0.00078076
EXP_OM	CUSTOMER	0.03255303	0.02339865	0.00400785	0.00125602	0.00018972	0.00004650	0.00027834	0.00008270	0.00010769	0.00000885	0.00000214	0.00003656	0.00015416	0.00004756	0.00008048	0.00001630	0.00000184	0.00215157	0.00068610
EXP_OM	TOTAL	1.00000000	0.43258602	0.02720612	0.08252624	0.00150036	0.00016365	0.08998560	0.01949982	0.00383306	0.00009254	0.00324638	0.04555800	0.04021056	0.00887393	0.20528383	0.03174186	0.00056645	0.00556170	0.00156387
Calculation of CUST_DEP_2 Allocator																				
CUST_DEP	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	1.00000000	0.72944254	0.04391236	0.08643739	0.02180074	0.00367576	0.03714454	0.01517663	0.00616385	0.00136968	-	0.01769325	0.01920157	0.01309038	-	-	-	0.00489131	-
	TOTAL	1.00000000	0.72944254	0.04391236	0.08643739	0.02180074	0.00367576	0.03714454	0.01517663	0.00616385	0.00136968	-	0.01769325	0.01920157	0.01309038	-	-	-	0.00489131	-
RB_GUP	PRODUCTION	0.55115145	0.25901240	0.01134596	0.04273413	0.00076529	0.00008012	0.04627695	0.00900967	0.00266564	0.00005262	0.00161714	0.02240456	0.02374066	0.00521524	0.10898325	0.01678459	0.00025153	0.00017232	0.00003937
	BULKTRAN	0.14426732	0.06779811	0.00296988	0.01118592	0.00020032	0.00002097	0.01211328	0.00235834	0.00069775	0.00001377	0.00042330	0.00586453	0.00621427	0.00136512	0.02852705	0.00439347	0.00006584	0.00004511	0.00001030
	SUBTRAN	0.03713710	0.01692893	0.00072221	0.00272767	0.00004923	0.00000694	0.00300530	0.00058598	0.00022842	-	0.00010152	0.00145314	0.00209627	-	0.00921476	-	0.00001673	-	-
	DISTPRI	0.15237895	0.10267206	0.00434685	0.01570360	0.00028128	-	0.01713909	0.00333778	-	-	0.00062205	0.00817819	-	-	-	-	0.00009804	-	-
	DISTSEC	0.07475165	0.05550135	0.00303403	0.00769636	-	-	0.00741976	-	-	-	0.00022338	-	-	-	-	-	0.00003638	0.00069215	0.00014825
	ENERGY	0.00112097	0.00039833	0.00002513	0.00008872	0.00000159	0.00000017	0.00009886	0.00001910	0.00000568	0.00000011	0.00000395	0.00005634	0.00005771	0.00001103	0.00029686	0.00004862	0.00000068	0.00000664	0.00000144
	CUSTOMER	0.03919256	0.01791070	0.00461710	0.00141118	0.00045897	0.00011528	0.00048264	0.00014113	0.00028349	0.00002117	0.00000387	0.00007528	0.00036854	0.00010586	0.00019054	0.00004234	0.00000213	0.01168628	0.00127606
	TOTAL	1.00000000	0.52022188	0.02706116	0.08154759	0.00175667	0.00022347	0.08653587	0.01545200	0.00388097	0.00008768	0.00299521	0.03803206	0.03247746	0.00669725	0.14721246	0.02126902	0.00047134	0.01260249	0.00147542
CUST_DEP_FXNL	PRODUCTION	0.50619222	0.36318092	0.01841118	0.04529657	0.00949740	0.00131779	0.01986386	0.00884911	0.00423363	0.00082204	-	0.01042304	0.01403614	0.01019366	-	-	-	0.00006688	-
CUST_DEP_FXNL	BULKTRAN	0.13249897	0.09506487	0.00481924	0.01185666	0.00248600	0.00034494	0.00519949	0.00231631	0.00110818	0.00021517	-	0.00272830	0.00367405	0.00266825	-	-	-	0.00001751	-
CUST_DEP_FXNL	SUBTRAN	0.03266922	0.02373734	0.00117194	0.00289123	0.00061090	0.00011410	0.00128999	0.00057554	0.00036277	-	-	0.00067603	0.00123937	-	-	-	-	-	-
CUST_DEP_FXNL	DISTPRI	0.18559366	0.14396428	0.00705367	0.01664522	0.00349077	-	0.00735676	0.00327830	-	-	-	0.00380466	-	-	-	-	-	-	-
CUST_DEP_FXNL	DISTSEC	0.09435732	0.07782265	0.00492334	0.00815785	-	-	0.00318485	-	-	-	-	-	-	-	-	-	-	0.00026864	-
CUST_DEP_FXNL	ENERGY	0.00087235	0.00055853	0.00004078	0.00009404	0.00001978	0.00000279	0.00004243	0.00001876	0.00000902	0.00000175	-	0.00002621	0.00003412	0.00002156	-	-	-	0.00000258	-
CUST_DEP_FXNL	CUSTOMER	0.04781626	0.02511396	0.00749221	0.00149580	0.00569589	0.00189614	0.00020717	0.00013861	0.00045024	0.00033072	-	0.00003502	0.00021789	0.00020690	-	-	-	0.00453570	-
CUST_DEP_FXNL	TOTAL	1.00000000	0.72944254	0.04391236	0.08643739	0.02180074	0.00367576	0.03714454	0.01517663	0.00616385	0.00136968	-	0.01769325	0.01920157	0.01309038	-	-	-	0.00489131	-

REVYEC_EXP_OM allocator is the basis to allocate the O&M portion of the Customer Annualization (Year End Customer) Adjustment. It is spread to the functions within each tariff class using total O&M.

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
REVYEC Total	TOTAL	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414
EXP_OM	PRODUCTION	0.48244003	0.22667652	0.00993369	0.03741452	0.00066990	0.00007013	0.04051281	0.00788598	0.00233377	0.00004608	0.00141576	0.01961382	0.02078572	0.00456487	0.09541249	0.01469840	0.00022024	0.00015085	0.00003448
	BULKTRAN	(0.11392060)	(0.05354854)	(0.00234458)	(0.00883086)	(0.00015817)	(0.00001656)	(0.00956389)	(0.00186238)	(0.00055086)	(0.00001087)	(0.00033420)	(0.00463030)	(0.00490584)	(0.00107802)	(0.02252216)	(0.00346765)	(0.00005197)	(0.00003561)	(0.00000813)
	SUBTRAN	(0.02937580)	(0.01339390)	(0.00057114)	(0.00215710)	(0.00003894)	(0.00000549)	(0.00237688)	(0.00046355)	(0.00018064)	-	(0.00008029)	(0.00114929)	(0.00165775)	-	(0.00728761)	-	(0.00001323)	-	-
	DISTPRI	0.10127255	0.06822663	0.00289013	0.01044088	0.00018697	-	0.01139399	0.00221840	-	-	0.00041355	0.00543680	-	-	-	-	0.00006520	-	-
	DISTSEC	0.03961006	0.02940479	0.00160856	0.00408034	-	-	0.00393313	-	-	-	0.00011842	-	-	-	-	-	0.00001929	0.00036689	0.00007866
	ENERGY	0.48330624	0.17173874	0.01083607	0.03825210	0.00068701	0.00007317	0.04262164	0.00823329	0.00244982	0.00004817	0.00170450	0.02429261	0.02488369	0.00475568	0.12798994	0.02096050	0.00029376	0.00286265	0.00062289
	CUSTOMER	0.03666752	0.02580623	0.00430299	0.00134830	0.00022229	0.00005430	0.00030165	0.00007558	0.00013315	0.00000987	0.00000246	0.00004055	0.00017326	0.00004938	0.00008892	0.00001977	0.00000199	0.00321724	0.00081957
	TOTAL	1.00000000	0.45491048	0.02665573	0.08054817	0.00156906	0.00017555	0.08682244	0.01608732	0.00418525	0.00009325	0.00324020	0.04360419	0.03927908	0.00829190	0.19368157	0.03221103	0.00053528	0.00656202	0.00154747
REVYEC_EXP_OM	PRODUCTION	(0.70072779)	2.10952880	(0.07086782)	(0.25638944)	0.04248480	0.00401464	(0.70045554)	(2.22309022)	0.29710226	-	0.08636593	0.00003942	0.19279881	(0.45302114)	(1.32480698)	1.53863589	(0.00000206)	0.05400380	0.00293107
REVYEC_EXP_OM	BULKTRAN	0.16553377	(0.49834092)	0.01672643	0.06051499	(0.01003127)	(0.00094805)	0.16535716	0.52501357	(0.07012723)	-	(0.02038725)	(0.00000931)	(0.04550432)	0.10698337	0.31272129	(0.36299485)	0.00000049	(0.01274918)	(0.00069114)
REVYEC_EXP_OM	SUBTRAN	0.12111271	(0.12464816)	0.00407453	0.01478193	(0.00246929)	(0.00031414)	0.04109570	0.13067652	(0.02299647)	-	(0.00489799)	(0.00000231)	(0.01537652)	-	0.10118880	-	0.00000012	-	-
REVYEC_EXP_OM	DISTPRI	(0.24250515)	0.63494025	(0.02061846)	(0.07154791)	0.01185766	-	(0.19699910)	(0.62537596)	-	-	0.02522805	0.00001093	-	-	-	-	(0.00000061)	-	-
REVYEC_EXP_OM	DISTSEC	0.31146337	0.27365093	(0.01147559)	(0.02796121)	-	-	(0.06800272)	-	-	-	0.00722384	-	-	-	-	-	(0.00000018)	0.13134266	0.00668565
REVYEC_EXP_OM	ENERGY	(0.08182657)	1.59825916	(0.07730544)	(0.26212911)	0.04356956	0.00418903	(0.73691669)	(2.32099969)	0.31187658	-	0.10398023	0.00004882	0.23080964	(0.47195707)	(1.77714642)	2.19415532	(0.00000275)	1.02479722	0.05294502
REVYEC_EXP_OM	CUSTOMER	1.42694966	0.24016160	(0.03069793)	(0.00923944)	0.01409730	0.00310855	(0.00521551)	(0.02130668)	0.01695140	-	0.00015020	0.00000008	0.00160708	(0.00490039)	(0.00123466)	0.00206958	(0.00000002)	1.15173495	0.06966355
REVYEC_EXP_OM	TOTAL	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
SEPTEMBER 30, 2014

REVSALES_FXNL allocator is the spreading of the REVSALES allocator to all functions within each tariff class. It is spread using the RSALE allocator as a basis.

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
REVSALES TOTAL		1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
RSALE	PRODUCTION	0.35030076	0.14623436	0.00879110	0.03346729	0.00047755	0.00004801	0.03387378	0.00680905	0.00183695	0.00003638	0.00108332	0.01480413	0.01733856	0.00319988	0.07043955	0.01118621	0.00019454	0.00039202	0.00008807
	BULKTRAN	(0.00237992)	(0.00964787)	0.00075019	0.00336060	0.00002290	0.00000222	0.00181942	(0.00030361)	0.00020665	0.00000928	0.00004255	0.00005823	0.00137938	(0.00030458)	(0.00067115)	0.00086202	0.00001701	0.00001240	0.00000444
	SUBTRAN	(0.00067550)	(0.00241423)	0.00018318	0.00082272	0.00000567	0.00000074	0.00045343	(0.00007549)	0.00006790	-	0.00001025	0.00001472	0.00046720	-	(0.00021594)	-	0.00000434	-	-
	DISTPRI	0.14271792	0.08379447	0.00545008	0.02052752	0.00030281	-	0.02001629	0.00352522	-	-	0.00066311	0.00831400	-	-	-	-	0.00012442	-	-
	DISTSEC	0.06035466	0.03893036	0.00343803	0.00912602	-	-	0.00775901	-	-	-	0.00021198	-	-	-	-	-	0.00004174	0.00065915	0.00018837
	ENERGY	0.40523469	0.13755594	0.00936060	0.03333966	0.00057131	0.00006028	0.03704787	0.00799900	0.00199084	0.00004406	0.00141031	0.02068394	0.02146505	0.00417056	0.10959966	0.01714023	0.00025611	0.00201305	0.00052620
	CUSTOMER	0.04444740	0.02246974	0.00639110	0.00205136	0.00042034	0.00010262	0.00052828	0.00012821	0.00029930	0.00003166	0.00000387	0.00006673	0.00038633	0.00006967	0.00015531	0.00004106	0.00000298	0.00961764	0.00168118
	TOTAL	1.00000000	0.41692276	0.03436428	0.10269517	0.00180058	0.00021388	0.10149809	0.01808238	0.00440165	0.00012139	0.00342540	0.04394175	0.04103652	0.00713554	0.17930744	0.02922952	0.00064115	0.01269426	0.00248827
REVSALES_FXNL	PRODUCTION	0.34965613	0.14720070	0.00874963	0.03331328	0.00049625	0.00004961	0.03348768	0.00557140	0.00199613	0.00003635	0.00112766	0.01479346	0.01743717	0.00293119	0.06962609	0.01210964	0.00019440	0.00044411	0.00009137
REVSALES_FXNL	BULKTRAN	(0.00229353)	(0.00971162)	0.00074665	0.00334514	0.00002380	0.00000229	0.00179868	(0.00024843)	0.00022456	0.00000928	0.00004429	0.00005818	0.00138722	(0.00027900)	(0.00066340)	0.00093318	0.00001700	0.00001405	0.00000461
REVSALES_FXNL	SUBTRAN	(0.00067586)	(0.00243019)	0.00018232	0.00081893	0.00000589	0.00000076	0.00044826	(0.00006177)	0.00007379	-	0.00001067	0.00001471	0.00046986	-	(0.00021344)	-	0.00000434	-	-
REVSALES_FXNL	DISTPRI	0.14231549	0.08434819	0.00542437	0.02043306	0.00031467	-	0.01978814	0.00288446	-	-	0.00069026	0.00830801	-	-	-	-	0.00012433	-	-
REVSALES_FXNL	DISTSEC	0.06056854	0.03918761	0.00342181	0.00908402	-	-	0.00767058	-	-	-	0.00022066	-	-	-	-	-	0.00004171	0.00074672	0.00019543
REVSALES_FXNL	ENERGY	0.40451767	0.13846493	0.00931645	0.03318624	0.00059369	0.00006228	0.03662560	0.00654506	0.00216336	0.00004403	0.00146804	0.02066904	0.02158712	0.00382036	0.10833396	0.01855517	0.00025593	0.00228051	0.00054590
REVSALES_FXNL	CUSTOMER	0.04591156	0.02261822	0.00636095	0.00204192	0.00043681	0.00010603	0.00052226	0.00010491	0.00032524	0.00003164	0.00000403	0.00006668	0.00038853	0.00006382	0.00015351	0.00004444	0.00000298	0.01089545	0.00174412
REVSALES_FXNL	TOTAL	1.00000000	0.41967784	0.03420220	0.10222259	0.00187111	0.00022098	0.10034121	0.01479562	0.00478308	0.00012130	0.00356561	0.04391009	0.04126990	0.00653637	0.17723672	0.03164244	0.00064068	0.01438084	0.00258143
		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

REVYEC_FXNL is a spreading of the REVYEC allocator to each function within the tariff classes using the RSALE allocator.

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
REVYEC TOTAL		1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414
RSALE	PRODUCTION	0.35030076	0.14623436	0.00879110	0.03346729	0.00047755	0.00004801	0.03387378	0.00680905	0.00183695	0.00003638	0.00108332	0.01480413	0.01733856	0.00319988	0.07043955	0.01118621	0.00019454	0.00039202	0.00008807
	BULKTRAN	(0.00237992)	(0.00964787)	0.00075019	0.00336060	0.00002290	0.00000222	0.00181942	(0.00030361)	0.00020665	0.00000928	0.00004255	0.00005823	0.00137938	(0.00030458)	(0.00067115)	0.00086202	0.00001701	0.00001240	0.00000444
	SUBTRAN	(0.00067550)	(0.00241423)	0.00018318	0.00082272	0.00000567	0.00000074	0.00045343	(0.00007549)	0.00006790	-	0.00001025	0.00001472	0.00046720	-	(0.00021594)	-	0.00000434	-	-
	DISTPRI	0.14271792	0.08379447	0.00545008	0.02052752	0.00030281	-	0.02001629	0.00352522	-	-	0.00066311	0.00831400	-	-	-	-	0.00012442	-	-
	DISTSEC	0.06035466	0.03893036	0.00343803	0.00912602	-	-	0.00775901	-	-	-	0.00021198	-	-	-	-	-	0.00004174	0.00065915	0.00018837
	ENERGY	0.40523469	0.13755594	0.00936060	0.03333966	0.00057131	0.00006028	0.03704787	0.00799900	0.00199084	0.00004406	0.00141031	0.02068394	0.02146505	0.00417056	0.10959966	0.01714023	0.00025611	0.00201305	0.00052620
	CUSTOMER	0.04444740	0.02246974	0.00639110	0.00205136	0.00042034	0.00010262	0.00052828	0.00012821	0.00029930	0.00003166	0.00000387	0.00006673	0.00038633	0.00006967	0.00015531	0.00004106	0.00000298	0.00961764	0.00168118
	TOTAL	1.00000000	0.41692276	0.03436428	0.10269517	0.00180058	0.00021388	0.10149809	0.01808238	0.00440165	0.00012139	0.00342540	0.04394175	0.04103652	0.00713554	0.17930744	0.02922952	0.00064115	0.01269426	0.00248827
REVYEC_FXNL	PRODUCTION	(0.54270748)	1.48490508	(0.04864797)	(0.17988134)	0.02639156	0.00225622	(0.50098652)	(1.70771860)	0.22235726	-	0.06251300	0.00002952	0.15393703	(0.36902159)	(1.05646224)	1.29042117	(0.00000152)	0.07254583	0.00465564
REVYEC_FXNL	BULKTRAN	0.11730396	(0.09796721)	(0.00415138)	(0.01806270)	0.00126577	0.00010413	(0.02690883)	0.07614610	0.02501477	-	0.00245509	0.00000012	0.01224652	0.03512504	0.01006597	0.09944150	(0.00000013)	0.00229436	0.00023485
REVYEC_FXNL	SUBTRAN	(0.00117675)	(0.02451482)	(0.00101370)	(0.00442199)	0.00031322	0.00003473	(0.00670618)	0.01893418	0.00821965	-	0.00059152	0.00000003	0.00414799	-	0.00323865	-	(0.00000003)	-	-
REVYEC_FXNL	DISTPRI	(0.41477046)	0.85087274	(0.03015953)	(0.11033215)	0.01673451	-	(0.29603696)	(0.88412980)	-	-	0.03826512	0.00001658	-	-	-	-	(0.00000097)	-	-
REVYEC_FXNL	DISTSEC	0.35664757	0.39530985	(0.01902529)	(0.04905089)	-	-	(0.11475429)	-	-	-	0.01223240	-	-	-	-	-	(0.00000033)	0.12197839	0.00995773
REVYEC_FXNL	ENERGY	(0.58806379)	1.39678195	(0.05179951)	(0.17919539)	0.03157342	0.00283263	(0.54793069)	(2.00615846)	0.24098515	-	0.08138239	0.00004125	0.19057319	(0.48096367)	(1.64379101)	1.97726719	(0.00000200)	0.37252387	0.02781590
REVYEC_FXNL	CUSTOMER	2.07276695	0.22816407	(0.03536692)	(0.01102574)	0.02323029	0.00482232	(0.00781323)	(0.03215587)	0.03622971	-	0.00022349	0.00000013	0.00342996	(0.00803501)	(0.00232934)	0.00473608	(0.00000002)	1.77978700	0.08887003
REVYEC_FXNL	TOTAL	1.00000000	4.23355166	(0.19016430)	(0.55197020)	0.09950877	0.01005002	(1.50113670)	(4.53508245)	0.53280655	-	0.19766301	0.00008763	0.36433468	(0.82289523)	(2.68927797)	3.37186594	(0.00000501)	2.34912945	0.13153414

FORF_DISC_FXNL Calculation - In order to properly assign forfeited discounts to the various functions within the customer classes, allocate it using the RSALE allocator

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
FORF_DISC TOTAL		1.00000000	0.71112214	0.06620871	0.12269002	0.00178294	0.00066684	0.04297993	0.00580371	0.00223445	0.00021246	0.00214966	0.01012398	0.01530002	0.00447882	0.00857472	-	-	0.00567159	-
RSALE	PRODUCTION	0.35030076	0.14623436	0.00879110	0.03346729	0.00047755	0.00004801	0.03387378	0.00680905	0.00183695	0.00003638	0.00108332	0.01480413	0.01733856	0.00319988	0.07043955	0.01118621	0.00019454	0.00039202	0.00008807
	BULKTRAN	(0.00237992)	(0.00964787)	0.00075019	0.00336060	0.00002290	0.00000222	0.00181942	(0.00030361)	0.00020665	0.00000928	0.00004255	0.00005823	0.00137938	(0.00030458)	(0.00067115)	0.00086202	0.00001701	0.00001240	0.00000444
	SUBTRAN	(0.00067550)	(0.00241423)	0.00018318	0.00082272	0.00000567	0.00000074	0.00045343	(0.00007549)	0.00006790	-	0.00001025	0.00001472	0.00046720	-	(0.00021594)	-	0.00000434	-	-
	DISTPRI	0.14271792	0.08379447	0.00545008	0.02052752	0.00030281	-	0.02001629	0.00352522	-	-	0.00066311	0.00831400	-	-	-	-	0.00012442	-	-
	DISTSEC	0.06035466	0.03893036	0.00343803	0.00912602	-	-	0.00775901	-	-	-	0.00021198	-	-	-	-	-	0.00004174	0.00065915	0.00018837
	ENERGY	0.40523469	0.13755594	0.00936060	0.03333966	0.00057131	0.00006028	0.03704787	0.00799900	0.00199084	0.00004406	0.00141031	0.02068394	0.02146505	0.00417056	0.10959966	0.01714023	0.00025611	0.00201305	0.00052620
	CUSTOMER	0.04444740	0.02246974	0.00639110	0.00205136	0.00042034	0.00010262	0.00052828	0.00012821	0.00029930	0.00003166	0.00000387	0.00006673	0.00038633	0.00006967	0.00015531	0.00004106	0.00000298	0.00961764	0.00168118
	TOTAL	1.00000000	0.41692276	0.03436428	0.10269517	0.00180058	0.00021388	0.10149809	0.01808238	0.00440165	0.00012139	0.00342540	0.04394175	0.04103652	0.00713554	0.17930744	0.02922952	0.00064115	0.01269426	0.00248827
FORF_DISC_FXNL	PRODUCTION	0.34060038	0.24942388	0.01693756	0.03998340	0.00047287	0.00014971	0.01434404	0.00218543	0.00093251	0.00006368	0.00067985	0.00341080	0.00646450	0.00200850	0.00336851	-	-	0.00017515	-
FORF_DISC_FXNL	BULKTRAN	(0.00983515)	(0.01645584)	0.00144537	0.00401491	0.00002268	0.00000691	0.00077044	(0.00009745)	0.00010491	0.00001625	0.00002670	0.00001342	0.00051429	(0.00019118)	(0.00003210)	-	-	0.00000554	-
FORF_DISC_FXNL	SUBTRAN	(0.00239813)	(0.00411783)	0.00035294	0.00098290	0.00000561	0.00000230	0.00019201	(0.00002423)	0.00003447	-	0.00000643	0.00000339	0.00017419	-	(0.00001033)	-	-	-	-
FORF_DISC_FXNL	DISTPRI	0.19018732	0.14292360	0.01050052	0.02452425	0.00029984	-	0.00847601	0.00113145	-	-	0.00041615	0.00191551	-	-	-	-	-	-	-
FORF_DISC_FXNL	DISTSEC	0.08764130	0.06640136	0.00662396	0.01090286	-	-	0.00328560	-	-	-	0.00013303	-	-	-	-	-	-	0.00029450	-
FORF_DISC_FXNL	ENERGY	0.33499615	0.23462158	0.01803482	0.03983093	0.00056571	0.00018795	0.01568813	0.00256735	0.00101063	0.00007712	0.00088507	0.00476548	0.00800301	0.00261777	0.00524120	-	-	0.00089940	-
FORF_DISC_FXNL	CUSTOMER	0.05880813	0.03832539	0.01231355	0.00245076	0.00041623	0.00031997	0.00022371	0.00004115	0.00015194	0.00005541	0.00000243	0.00001537	0.00014404	0.00004373	0.00000743	-	-	0.00429701	-
FORF_DISC_FXNL	TOTAL	1.00000000	0.71112214	0.06620871	0.12269002	0.00178294	0.00066684	0.04297993	0.00580371	0.00223445	0.00021246	0.00214966	0.01012398	0.01530002	0.00447882	0.00857472	-	-	0.00567159	-

WEATHER_FXNL Calculation - In order to properly assign the weather normalization load adjustment to the various functions within the customer classes, allocate it using the RSALE allocator

ALLOCATOR	FUNCTION	Total	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	QP-SEC	QP-PRI	QP-SUB	QP-TRA	CIP-TOD-SUB	CIP-TOD-TRA	MW	OL	SL
WEATHER_NORM TOTAL		1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RSALE	PRODUCTION	0.35030076	0.14623436	0.00879110	0.03346729	0.00047755	0.00004801	0.03387378	0.00680905	0.00183695	0.00003638	0.00108332	0.01480413	0.01733856	0.00319988	0.07043955	0.01118621	0.00019454	0.00039202	0.00008807
	BULKTRAN	(0.00237992)	(0.00964787)	0.00075019	0.00336060	0.00002290	0.00000222	0.00181942	(0.00030361)	0.00020665	0.00000928	0.00004255	0.00005823	0.00137938	(0.00030458)	(0.00067115)	0.00086202	0.00001701	0.00001240	0.00000444
	SUBTRAN	(0.00067550)	(0.00241423)	0.00018318	0.00082272	0.00000567	0.00000074	0.00045343	(0.00007549)	0.00006790	-	0.00001025	0.00001472	0.00046720	-	(0.00021594)	-	0.00000434	-	-
	DISTPRI	0.14271792	0.08379447	0.00545008	0.02052752	0.00030281	-	0.02001629	0.00352522	-	-	0.00066311	0.00831400	-	-	-	-	0.00012442	-	-
	DISTSEC	0.06035466	0.03893036	0.00343803	0.00912602	-	-	0.00775901	-	-	-	0.00021198	-	-	-	-	-	0.00004174	0.00065915	0.00018837
	ENERGY	0.40523469	0.13755594	0.00936060	0.03333966	0.00057131	0.00006028	0.03704787	0.00799900	0.00199084	0.00004406	0.00141031	0.02068394	0.02146505	0.00417056	0.10959966	0.01714023	0.00025611	0.00201305	0.00052620
	CUSTOMER	0.04444740	0.02246974	0.00639110	0.00205136	0.00042034	0.00010262	0.00052828	0.00012821	0.00029930	0.00003166	0.00000387	0.00006673	0.00038633	0.00006967	0.00015531	0.00004106	0.00000298	0.00961764	0.00168118
	TOTAL	1.00000000	0.41692276	0.03436428	0.10269517	0.00180058	0.00021388	0.10149809	0.01808238	0.00440165	0.00012139	0.00342540	0.04394175	0.04103652	0.00713554	0.17930744	0.02922952	0.00064115	0.01269426	0.00248827
WEATHER_FXNL	PRODUCTION	0.35074689	0.35074689	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	BULKTRAN	(0.02314067)	(0.02314067)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	SUBTRAN	(0.00579060)	(0.00579060)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	DISTPRI	0.20098320	0.20098320	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	DISTSEC	0.09337546	0.09337546	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	ENERGY	0.32993148	0.32993148	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	CUSTOMER	0.05389424	0.05389424	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_FXNL	TOTAL	1.00000000	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2014

					Proposed Revenue Allocation						
Current Class (1)	**Current Revenue** (2)	**Rate Base** (3)	**Current Income** (4)	**Current ROR %** (5)	**Income Increase** (6)	**Income** (7)	**ROR %** (8)	**Revenue Increase** (9)	**Less: Adjust Trans to OATT** (10)	**Sales Revenue** (11)	**Percent Increase** (12)
RS	230,140,574	616,814,372	28,051,963	4.55	(1,524,898)	26,527,064	4.30	(2,501,105)	7,903,930	235,543,399	2.35
SGS	19,611,844	34,492,915	5,062,042	14.68	(85,275)	4,976,767	14.43	(139,867)	(643,599)	18,828,378	-3.99
MGS	59,677,591	98,516,888	15,372,414	15.60	(243,556)	15,128,858	15.36	(399,476)	(2,871,337)	56,406,778	-5.48
LGS	70,569,638	124,761,218	14,825,960	11.88	(308,437)	14,517,523	11.64	(505,892)	(1,829,055)	68,234,691	-3.31
QP	54,126,867	86,428,529	9,366,439	10.84	(213,671)	9,152,768	10.59	(350,458)	(1,348,509)	52,427,900	-3.14
CIP-TOD	117,423,244	172,708,356	15,707,857	9.10	(426,973)	15,280,884	8.85	(700,312)	(1,313,469)	115,409,463	-1.71
MW	364,284	575,126	82,849	14.41	(1,422)	81,427	14.16	(2,332)	(14,795)	347,157	-4.70
OL	7,256,325	21,337,177	2,429,925	11.39	(52,750)	2,377,175	11.14	(86,520)	(7,305)	7,162,499	-1.29
SL	1,422,710	2,551,935	434,576	17.03	(6,309)	428,267	16.78	(10,348)	(2,769)	1,409,592	-0.92
Total	560,593,075	1,158,186,516	91,334,026	7.89	(2,863,291)	88,470,733	7.64	(4,696,310)	(126,908)	555,769,857	-0.86
								Net Revenue Increase	(4,696,331)		

Gross Rev Conversion Factor: 1.640179

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2014

					Current Equalized Rate of Return						
Current Class (1)	**Current Revenue** (2)	**Rate Base** (3)	**Current Income** (4)	**Current ROR %** (5)	**Percent Increase** (6)	**Revenue Increase** (7)	**Income Increase** (8)	**Income** (9)	**ROR %** (10)	**Sales Revenue** (11)	**Current Subsidy** (12)=(11)-(2)
RS	230,140,574	616,814,372	28,051,963	4.55	14.67	33,770,821	20,589,717	48,641,680	7.89	263,911,395	33,770,821
SGS	19,611,844	34,492,915	5,062,042	14.68	-19.59	(3,841,212)	(2,341,947)	2,720,095	7.89	15,770,632	(3,841,212)
MGS	59,677,591	98,516,888	15,372,414	15.60	-20.90	(12,470,969)	(7,603,420)	7,768,994	7.89	47,206,622	(12,470,969)
LGS	70,569,638	124,761,218	14,825,960	11.88	-11.59	(8,180,149)	(4,987,351)	9,838,609	7.89	62,389,489	(8,180,149)
QP	54,126,867	86,428,529	9,366,439	10.84	-7.73	(4,183,649)	(2,550,727)	6,815,712	7.89	49,943,218	(4,183,649)
CIP-TOD	117,423,244	172,708,356	15,707,857	9.10	-2.92	(3,424,957)	(2,088,160)	13,619,697	7.89	113,998,287	(3,424,957)
MW	364,284	575,126	82,849	14.41	-16.88	(61,499)	(37,495)	45,354	7.89	302,785	(61,499)
OL	7,256,325	21,337,177	2,429,925	11.39	-16.89	(1,225,683)	(747,286)	1,682,639	7.89	6,030,642	(1,225,683)
SL	1,422,710	2,551,935	434,576	17.03	-26.90	(382,707)	(233,332)	201,244	7.89	1,040,003	(382,707)
Total	560,593,075	1,158,186,516	91,334,026	7.89	0.00	(4)	(2)	91,334,024	7.89	560,593,071	(4)

Gross Rev Conversion Factor: 1.640179

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended September 30, 2014

					Proposed Equalized Rate of Return						100% of		
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)	Proposed Increase (13)=(7)-(12)	Percent Increase (14)
RS	230,140,574	616,814,372	28,051,963	4.55	13.59	31,269,716	19,064,819	47,116,782	7.64	261,410,290	33,770,821	(2,501,105)	-1.09
SGS	19,611,844	34,492,915	5,062,042	14.68	-20.30	(3,981,079)	(2,427,222)	2,634,820	7.64	15,630,765	(3,841,212)	(139,867)	-0.71
MGS	59,677,591	98,516,888	15,372,414	15.60	-21.57	(12,870,445)	(7,846,976)	7,525,438	7.64	46,807,146	(12,470,969)	(399,476)	-0.67
LGS	70,569,638	124,761,218	14,825,960	11.88	-12.31	(8,686,041)	(5,295,788)	9,530,172	7.64	61,883,597	(8,180,149)	(505,892)	-0.72
QP	54,126,867	86,428,529	9,366,439	10.84	-8.38	(4,534,107)	(2,764,398)	6,602,041	7.64	49,592,760	(4,183,649)	(350,458)	-0.65
CIP-TOD	117,423,244	172,708,356	15,707,857	9.10	-3.51	(4,125,269)	(2,515,133)	13,192,724	7.64	113,297,975	(3,424,957)	(700,312)	-0.60
MW	364,284	575,126	82,849	14.41	-17.52	(63,831)	(38,917)	43,932	7.64	300,453	(61,499)	(2,332)	-0.64
OL	7,256,325	21,337,177	2,429,925	11.39	-18.08	(1,312,203)	(800,036)	1,629,889	7.64	5,944,122	(1,225,683)	(86,520)	-1.19
SL	1,422,710	2,551,935	434,576	17.03	-27.63	(393,055)	(239,641)	194,935	7.64	1,029,655	(382,707)	(10,348)	-0.73
Total	560,593,075	1,158,186,516	91,334,026	7.89	-0.84	(4,696,314)	(2,863,293)	88,470,733 (a)	7.64	555,896,761	(4)	(4,696,310)	-0.84
								88,470,733					

Gross Rev Conversion Factor: 1.640179

(a) Required net operating income from Section V, Schedule 2, Column (3), Line 3

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	**)**	
A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	
Environmental Compliance Plan; (3) An Order	**)**	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

H. KEVIN STOGRAN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, H. Kevin Stogran, being duly sworn, deposes and says he is the Managing Director, Cyber Risk and Security Services for American Electric Power Service Corporation and that he has personal knowledge of the set forth in the forgoing testimony for which he is identified as the witness and the information contained therein is true and correct to the best of his information, knowledge and belief.

H. Kevin Stogran

STATE OF OHIO)
) Case No. 2014-00396
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by H. Kevin Stogran, this the 12th day of December, 2014.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

My Commission Expires: October 1, 2016

DIRECT TESTIMONY OF
H. KEVIN STOGRAN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
H. KEVIN STOGRAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is H. Kevin Stogran. I am the Managing Director of Cyber Risk and Security Services for the American Electric Power Service Corporation ("AEPSC"), a subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or "Company") and AEPSC is Kentucky Power's services provider company.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR BACKGROUND AND EMPLOYMENT HISTORY.

A. I received a Bachelor's Degree in Mechanical Engineering from Clarkson University of Potsdam, New York in 1978. I joined AEPSC in Canton, Ohio that same year in the Plant Engineering Division supporting AEP's power plants. In 1985, I transferred to the Mechanical Engineering Division where I worked on AEP's clean coal technology projects until I left AEP in 1995. I rejoined AEPSC in late 1996 supporting the daily operations of the power plants and interfacing with the trading functions relative to plant output. In 2000, I transferred to the Commercial Operations organization where I led efforts to interface power plant operations with AEP's trading functions and generation dispatch. From 2006 thru 2010 I oversaw the information systems support for Commercial Operations market operations functions including support and compliance for NERC compliance. In 2010 I transferred to Information Technology where I led the enterprise cybersecurity and risk functions across AEP.

Q. WHAT ARE YOUR RESPONSIBILITIES?

A. As Managing Director of IT Cyber Risk and Security Services I led the enterprise functions which provide cybersecurity services across AEP's 11 state network, including: cybersecurity programs and awareness; cybersecurity intelligence and defense; cybersecurity monitor and response; cyber registration services; cybersecurity testing and assessment; enterprise business continuity; and IT's NERC and SOx compliance functions, all within the Information Technology organization.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. No.

III. PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my testimony is to support the need for the proposed North American Electric Reliability Corporation ("NERC") Compliance and Cybersecurity Rider as proposed by Company Witness Wohnhas.

IV. NERC COMPLIANCE AND CYBERSECURITY

Q. WHAT IS NERC?

A. NERC is the North American Electric Reliability Corporation a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. Beginning in 2007, all bulk power system owners, operators, and users were required to comply with reliability standards established by NERC, which are implemented and enforced through Federal Energy Regulatory Commission ("FERC") approved delegation agreements to eight Regional Entities. Kentucky Power registered and operates within the region of the Reliability First Corporation.

Q. WHAT IS CYBERSECURITY?

A. Cybersecurity, also referred to as information technology security, focuses on protecting computers, networks, programs and data from unintended or unauthorized access, change or destruction.

Utility cybersecurity encompasses protection and security of physical distribution and transmission grids, substations, power plants, and business offices, as well as equipment, processes and systems that communicate, store, and act on data. Cybersecurity encompasses not only utility-owned systems, but it also includes aspects of customer and third party components that interact with the grid, such as advanced meters and 3rd party cloud hosted services. Cybersecurity focuses on hardware and software, as well as the data and the networks that use the data to keep the system operating. Finally, there are human elements to cybersecurity, including system operators, customers, and potential criminals interacting at all levels of a system. The dynamic and broad landscape that is covered by cybersecurity is continuously evolving, and emerging threats and exploits merits dedicated attention, flexibility to address emerging risks, and constant vigilance. With such a dynamic and broad landscape to consider, cybersecurity cannot be a stagnant prescription. A utility's cybersecurity measures must constantly evolve as technology, threats and vulnerabilities evolve, introducing the building blocks that stand the test of time while still being flexible enough to meet changing cybersecurity requirements.

Q. WHAT DOES THE TERM "NERC COMPLIANCE AND CYBERSECURITY" MEAN WITH RESPECT TO AN ELECTRIC UTILITY LIKE KENTUCKY POWER COMPANY?

A. For decades, electric system security was defined as the ability of the system to withstand sudden, unexpected disturbances, such as a short circuit or an unanticipated loss of system elements due to natural causes. In today's world, the security focus of utilities has expanded to include withstanding disturbances caused by manmade physical or cyber attacks. Cybersecurity refers to the prevention and mitigation of impacts from these types of cyberattacks. With the list of potential threats expanding, NERC has begun to implement new programs and requirements to counteract the increased threats. The Critical Infrastructure Protection (CIP) Standards have been under constant revision since their inception in 2008, when version 1 became enforceable. With the advent of CIP version 5 and the introduction of a new standard for physical security, there will be a 37.5% increase in the number of CIP Standards that will be enforceable over the next two years. It is worth noting that these new / revised standards will require significant investments required in both cyber security and physical security protection measures. The volume of these changes and the new standards being introduced are indicators of the continuously expanding reach of NERC security requirements and the Company's commensurately expanding compliance obligation.

Recent events further illustrate the heightened attention these issues are receiving. For example, the Grid 20/20 conference hosted by the PJM on November 11-12, 2013 focused on the need for the electric grid to become more resilient in the face of a rising number of physical challenges, such as sabotage attempts and cyberattacks. This forum was followed on November 13-14, 2013 with the NERC conducting its second Grid Security Exercise (GridEx II) to exercise NERC and industry crisis response plans and identify actionable improvement recommendations for plans, security programs, and skills. Kentucky Power participated in this NERC event.

President Obama's administration and United States energy officials have also called on Congress to pass a bill to resolve questions about potential liability in the aftermath of cyberattacks, as well as how energy companies can share potential threat information with the government or each other. Further, President Obama issued Executive Order (EO) 13636, "Improving Critical Infrastructure Cybersecurity", in early 2013 that has resulted in NIST (National Institute of Standards and Technology) developing and issuing in February 2014 the "Framework for Improving Critical Infrastructure Cybersecurity" which the

Department of Energy is now working to develop into an implementation plan for the Electric Subsector.

Additionally, in February 2014, The National Association of Regulatory Utility Commissioners issued the "Cybersecurity for State Regulators Primer 2.0" which provided updated guidance on utility cybersecurity for state regulators while addressing the need for strong cybersecurity capabilities. On November 20th, 2014, the House Select Intelligence Committee conducted a hearing to discuss the United States efforts to combat cybersecurity threats. During that hearing, Admiral Michael Rogers, National Security Agency (NSA) Director & U.S. Cyber Command Commander, addressed the current threat landscape against the nation's critical infrastructure and the threats poised by a number of nation-state adversaries and their associates. The House Committee further raised the issue of the need to improve cybersecurity capabilities across the various critical infrastructure sectors.

These recent examples show the increased focus on these issues and evolving nature of the industry's response.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For:	**)**	
(1) A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	**Case No. 2014-00396**
Environmental Compliance Plan; (3) An Order	**)**	
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

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

Alex E. Vaughan

STATE OF OHIO)
) Case No. 2014-00396
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, this the 15 day of December, 2014.

Kelli N. Beuzard
Notary Public

My Commission Expires: 10/1/2019

NOTARIAL SEAL STATE OF OHIO

Kelli N. Beuzard
Notary Public, State of Ohio
My Commission Expires 10-01-2019

DIRECT TESTIMONY OF
ALEX E. VAUGHAN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
ALEX E. VAUGHAN
FOR KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2014-00396

I. INTRODUCTION

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

A. My name is Alex E. Vaughan. I am employed by American Electric Power Service Corporation ("AEPSC") as Manager, Regulated Pricing and Analysis. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My responsibilities include the oversight of cost of service analyses, rate design and special contracts for the AEP East System operating companies

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEP I worked for a retail bank and a holding company where I held various underwriting, finance and accounting positions. In 2007 I joined AEPSC as a Settlement Analyst in the Regional Transmission Organization (RTO) Settlements Group. I later became the PJM Settlements Lead Analyst where I was responsible for reconciling AEP's settlement of its activities in the PJM market with the monthly PJM invoices and for resolving billing issues with PJM. In 2010 I transferred to

Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's 11 state jurisdictions and at the Federal Energy Regulatory Commission (FERC). In addition, I was responsible for performing financial analyses related to AEP's generation resources and loads, power pools and PJM. In September of 2012, I was promoted to my current position.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I submitted direct testimony to the Kentucky Public Service Commission (the Commission) in Case No. 2013-00197 on behalf of Kentucky Power Company. I submitted direct testimony to the Indiana Utility Regulatory Commission in Cause No. 43774-PJM-3 on behalf of Indiana Michigan Power Company, a Kentucky Power affiliate. Additionally, I submitted testimony to the Virginia State Corporation Commission in case numbers PUE-2012-00094, PUE-2013-00009, PUE-2013-00111, PUE-2014-00007 and PUE-2014-00026 on behalf of Appalachian Power Company. I also submitted direct testimony to the West Virginia Public Service Commission in Case No. 14-1152-E-42T on behalf of Appalachian Power Company and Wheeling Power Company, both of which are Kentucky Power affiliates.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's proposed rate design, including the changes to the residential and small commercial service charges, and the combination of tariffs QP and CIP-TOD. Additionally, I sponsor certain operation and maintenance expense and operating revenue adjustments detailed in Section V, Exhibit 2.

Among these are adjustments related to (1) the removal of AEP East Pool costs and revenues; (2) adjustments to the test year amount of PJM charges and credits and; (3) adjustments to the test year level of Off System Sales (OSS) margins. Furthermore, I support the proposed PJM Rider, the proposed Big Sandy Unit 1 Operation Rider (BS1OR) and the Company's proposed treatment of transmission function revenues and expenses in base rates.

Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES?

A. Yes, I am sponsoring the following exhibits:

- Exhibit AEV 1 – Base Rate Revenue Target Summary
- Exhibit AEV 2 – Fixed Distribution Cost Study
- Exhibit AEV 3 – Marginal Customer Connection Study
- Exhibit AEV 4 – BS1OR Revenue Requirement and Rate Design
- Exhibit AEV 5 – Adjusted Test Year PJM Charge and Credit Detail
- Exhibit AEV 6 – PJM Rider Rate Design
- Exhibit AEV 7– Adjusted Test Year OSS Margin Calculations

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

III. RATE DESIGN

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE COMPANY'S PROPOSED RATES.

A. In general, the Company's approach is to design rates and rate components which reflect the underlying costs of the Company. This includes collecting basic service-related costs through basic service charges and recognizing the differences in the costs to serve customers at different service delivery voltages.

The rate design process involved a number of steps which varied with each tariff. The cost components developed by Witness Stegall in the class cost of service study provided guidance as to the relative amounts of revenue that should be recovered from service charges, energy charges and demand charges. In general, where sufficient metering data is available, full cost service charges, energy and demand rates were developed for each class by dividing the component-allocated proposed revenues by the test year billing units. These initial rates were then compared to the current rates to determine which price changes would need to be moderated to mitigate rate impacts that could cause individual bill impacts that might be considered too severe.

Q. FOR WHICH TARIFFS IS THE COMPANY PROPOSING RATE DESIGN CHANGES IN THIS PROCEEDING?

A. The Company is refining or proposing new rate designs for the following tariffs:

a. Residential Service (RS)
b. Small General Service (SGS)
c. Quantity Power (QP)
d. Commercial and Industrial Power – Time-of-day (CIP TOD)
e. Proposed new tariff Industrial General Service (IGS)

<u>i. Residential Service Rate Design</u>

Q. WHAT CHANGES TO THE RESIDENTIAL SERVICE RATE DESIGN IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing to increase the basic service charge to $16 per month from $8 and increase the energy charge.

Q. WHAT IS THE RATIONALE FOR INCREASING THE RESIDENTIAL BASIC SERVICE CHARGE?

A. The goal is to institute a basic service charge for residential customers that more accurately reflects the actual cost of providing service. The rate structures for rate classes that utilize demand charges are better aligned with cost causation principles than those that do not, such as the residential class, because fixed costs are generally recovered through a demand charge. Without a separate demand charge in the residential rate, the majority of fixed distribution costs are recovered through the energy charge. Such costs, or at least a larger portion of those costs, should be recovered in the basic service charge since these costs are fixed in nature and are the result of simply connecting a customer to the distribution system. The current basic service charge is low and only partially compensates the Company for the fixed cost of providing electric service.

As it currently stands, fixed costs are mostly recovered in the energy component of the bill, which penalizes higher usage customers who then pay more than their share of fixed cost recovery. Recouping these fixed costs through the energy charge results in an intra-class subsidy between high and low usage customers.

A higher basic service charge would also help eliminate the subsidy year-round customers provide to seasonal customers, who may only register normal usage a few months per year. With the current basic service charge, seasonal customers do not appropriately bear the costs they impose on the system.

To further illustrate this point, I offer the following example using three hypothetical Kentucky residential customers. These three customers live next door to each other on the same street. All three customers' homes were connected to the Company's distribution system using the same equipment for the same cost. Let's assume that their electric rates are structured in the same fashion as the Company's current residential rate design in that the rates include a basic service charge of $8 with the balance of the distribution revenue requirement being recovered through a charge per kWh.

	Customer 1	Customer 2	Customer 3	Total
Home Size (Sq Ft)	2500	800	800	
Household Description	Family of 5	Single person	Retired couple, spend 5 months of the year in vacation home	
Avg Monthly Usage (kWh)	2,200	1,000	400	3,600
Annual Avg Usage (kWh)	26,400	12,000	4,800	43,200
Annual Fixed Dist Connection Cost	$ 480	$ 480	$ 480	$ 1,440
Annual Basic Service Charge ($8*12)	$ 96	$ 96	$ 96	$ 288
Per kWh charge ($/kWh) = ($1,440-$288)/43,200	0.0267	0.0267	0.0267	
Annual Example Bill for Fixed Distribution Costs =$96 + (annual kWh* 0.0267)	$ 800	$ 416	$ 224	$ 1,440
Subsidy Received/(Paid)	$ (320)	$ 64	$ 256	$ -

As can be seen in the above table, Customer 1 is providing an intra-rate class subsidy to Customers 2 and 3. In this simple example we have one customer paying in excess of its appropriate share and two customers paying less than their appropriate share for the same costs that each of the three customers equally caused by being connected to the Company's distribution system.

These subsidies between like customers are exactly what the Company's proposed increase to the basic service charge is intended to reduce. Here is the same table with the Company's proposed basic service charge:

	Customer 1	Customer 2	Customer 3	Total
Home Size (Sq Ft)	2500	800	800	
Household Description	Family of 5	Single person	Retired couple, spend 5 months of the year in vacation home	
Avg Monthly Usage (kWh)	2,200	1,000	400	3,600
Annual Avg Usage (kWh)	26,400	12,000	4,800	38,400
Annual Fixed Dist Connection Cost	$ 480	$ 480	$ 480	$ 1,440
Annual Basic Service Charge ($16*12)	$ 192	$ 192	$ 192	$ 576
Per kWh charge ($/kWh) = ($1,440-$576)/38,400	0.0200	0.0200	0.0200	
Annual Example Bill for Fixed Distribution Costs =$192+ (annual kWh* 0.0200)	$ 720	$ 432	$ 288	$ 1,440
Subsidy Received/(Paid)	$ (240)	$ 48	$ 192	$ -

Proposed Subsidy Reduction (paid)/received	$ (80)	$ 16	$ 64	$ -

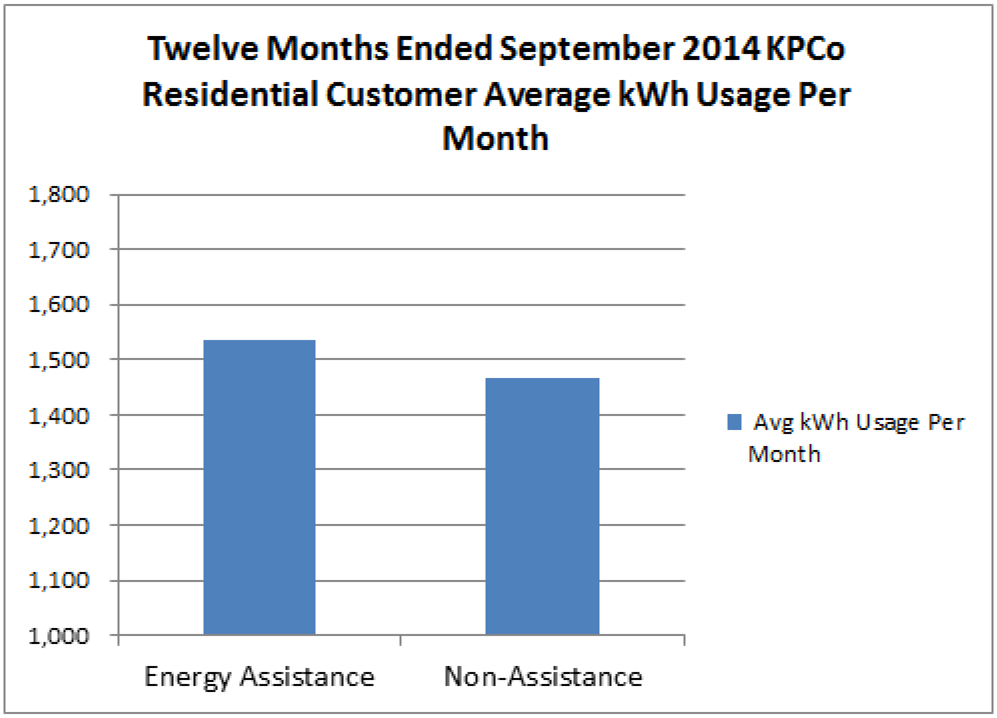
As can be seen, the Company's proposal reduces the intraclass subsidies as it narrows the gap between the service charge and the actual cost to provide each customer with distribution service.

Q. HOW WILL THE INCREASED BASIC SERVICE CHARGE IMPACT MONTHLY BILL VOLATILITY?

A. By removing a portion of the fixed costs from the energy charge, the average customer will see less volatility in bills from high usage months. This is especially true the Company's electric heating customers. They tend to experience very high usage months in the winter to heat their homes. This proposed rate design change will lessen the bill impact in those months that results from their increased winter heating usage. This is a desirable result since these are the same months when customers tend to have the most difficulty paying their electricity bills. Further, as described above this is an appropriate result based upon cost causation principles.

Q. WHAT IMPACT WOULD THE HIGHER BASIC SERVICE CHARGE HAVE ON LOWER INCOME CUSTOMERS?

A. It is sometimes assumed that lower income customers are also low usage customers. For various reasons this often is not the case. For example, lower income customers often do not have the resources to invest in weatherization and energy efficient appliances. The following graphic illustrates test year usage for residential low income energy assistance customers versus customers without assistance in Kentucky Power's service territory. The average kWh usage for the low income energy assistance customers (1,536 kWh/month) is greater than the average usage by non-assistance customers (1,468 kWh/month), so the average low income customer will benefit from the new rate structure.



Q. HOW WAS THE NEW BASIC SERVICE CHARGE DETERMINED?

A. I calculated the full cost basic service charge to be approximately $40 per month. However when taking the concept of gradualism into account, the Company proposes to limit the basic service charge to $16 per month in this proceeding. The $40 per unit cost represents the cost of the fixed portion of the distribution system used to serve the residential class. Said another way, this is the full cost of the portion of the distribution system that is required just to connect customers to the grid and stand ready to serve them. It does not include costs that vary by kW demand or kWh usage. It should also be noted that the $40 per month full cost basic service charge is a distribution only figure; it does not include any generation or transmission service costs.

Although the Company is only proposing to raise the basic service charge to $16 in this proceeding, cost causation principles would support a much higher basic service charge.

Q. HOW DID YOU CALCULATE THE FULL COST BASIC SERVICE CHARGE OF $40?

A. I performed a fixed cost study of the Company's distribution plant. This study is attached to my testimony as Exhibit AEV-2. This study compares the actual components of the Kentucky Power's distribution system and their component costs by distribution plant account classification to what the total cost would be if all components of these distribution plant components were the typical or average size installed by the Company when connecting the average distribution level customer. All component costs up to the typical level are classified as fixed costs that only vary with the number of customers connected to the distribution system. The costs above the typical level are classified as being related to demand since the additional cost of these facilities was incurred due to the need to install additional facilities to meet customer kilowatt (kW) demands.

The fixed distribution plant costs are also separated between the primary and secondary voltage levels in this study. The fixed amount of costs in plant accounts 364-368 as determined in the study is then compared to the total costs in those account classifications by voltage level to determine what percent of primary and secondary distribution costs only varies with the number of customers on the system. For rate design discussion purposes I will refer to these percentages as the "fixed distribution allocation factors."

The primary and secondary distribution revenue requirements from the class cost of service study are then multiplied by the respective fixed distribution allocation factors to calculate the fixed portion of these revenue requirements. The revenue requirement associated with distribution plant accounts 369-371 and the O&M related to customer accounts expense, customer information expense and customer service is also added to the fixed primary and secondary distribution revenue requirements to calculate the total fixed distribution revenue requirement. This amount was then divided by the total number of bills in the year, which produced the $40 per month cost.

Q. DID YOU EXPLORE ANY OTHER METHODS OF PRICING THE FULL COST BASIC SERVICE CHARGE?

A. Yes, I also calculated what the full cost basic service charge would be using what I will refer to as "the marginal customer connection" method. The study itself is attached to my testimony as Exhibit AEV-3. This study takes the Company's current average marginal cost to connect a residential customer to its distribution system. The total cost of the residential connection is then multiplied by the appropriate levelized carrying charge and divided by 12 to compute the monthly full cost basic service charge.

Using this method I calculated the full cost basic service charge for a Kentucky Power residential customer to be about $41 per month. In other words, the fixed monthly cost associated with connecting the next customer to the distribution system for the Company's jurisdiction is $41. It should be noted that this is only the cost of connecting the customer to the distribution grid; the $41 per month contains no generation costs, transmission costs or costs of existing distribution facilities.

Q. WILL THE COMPANY'S PROPOSED RESIDENTIAL BASIC SERVICE CHARGE DETER ENERGY CONSERVATION?

A. No. The Company is proposing to increase the basic service charge and the base rate kWh charge even before considering the Company's environmental surcharge, BS1OR and BSRR. An increase in usage will still result in an increased bill. Therefore customers are not receiving a price signal that would encourage additional consumption and it can't be credibly argued that the Company's proposal is anti-conservation.

Ideally, the Company would recover little to none of the residential class distribution revenue requirement through a kWh charge because the distribution revenue requirement does not vary with the amount of kWh consumed. However, the Company's current residential class metering infrastructure does not provide the information necessary to institute a kW demand charge which would be a better basis for collecting the distribution revenue requirement that is not collected in the basic service charge. This is because the fixed costs of the distribution system are incurred in two ways. First, by simply connecting a customer to the radial distribution system, these costs do not vary with the kWh consumed or the kW demands of customers; these are the portion of the distribution revenue requirement that the Company is proposing to include in its basic service charge. And, second, these costs are incurred by sizing the distribution system to meet customer(s) peak kW demand usage. These costs vary by peak demand requirements, not by kWh usage or by simply connecting a customer to the system. This second category of costs would ideally be collected through a demand charge but this cannot be done for all customers due to the current limitations of the Company's metering infrastructure. In fact, under the Company's proposal, nearly 90% of the Company's residential customer revenues are still being collected through a volumetric (per kWh) charge.

In the absence of a peak demand charge, the Company is proposing to move a portion of those fixed distribution costs that only vary with the number of customers connected to the system from the kWh charge to the basic service charge.

Q. IS SENDING THE CORRECT PRICE SIGNALS TO CUSTOMERS THROUGH RATES THAT REFLECT THE TRUE COST OF SERVICE IMPORTANT TO THE LONG TERM SUCCESS OF CONSERVATION EFFORTS?

A. Yes. While in the short term a higher kWh charge that does not reflect the true cost of service could encourage conservation, in the long term it provides confusion to customers and can result in customers making uneconomic decisions. Customers expect that when they use less energy, their bills will decrease, and initially, this is the result. But with fixed costs embedded in the kWh energy rate, the Company eventually will need to increase rates because it is not recovering its fixed cost of providing service and customers will therefore see their bills increase even though they have conserved energy. This example underlines the importance of sending accurate, cost based price signals to customers, which is exactly what the Company's proposed residential rate design takes a step towards.

ii. Small General Service Rate Design

Q. IS THE COMPANY PROPOSING A SIMILAR RATE DESIGN CHANGE TO THE SGS TARIFF?

A. Yes, the Company is proposing similar changes to the SGS tariff to increase the basic service charge. The SGS basic service charge is currently slightly higher than that of the Residential schedules. The Company is proposing to increase the basic service charges for SGS by the same $8 that it proposed as a change for the Residential basic service charge. This results in a proposed basic service charge of $19.50 for customers receiving service under Tariff SGS. The proposed SGS basic service charge is also below the full cost basic service charge I calculated for this tariff which can be seen in Exhibit AEV 2.

The Company is proposing this change for the same reasons discussed above regarding the Residential rate design.

iii. QP, CIP TOD and New Tariff IGS

Q. WHAT IS THE COMPANY PROPOSING IN REGARDS TO TARIFFS QP AND CIP TOD?

A. In order to comply with the Commission -approved Stipulation and Settlement Agreement in Case No. 2012-00578 ("Stipulation and Settlement Agreement"), the Company proposes to combine the QP and CIP TOD tariffs into a new tariff named Industrial General Service (IGS). New tariff IGS utilizes the rate design of current tariff CIP TOD which has an on-peak demand charge, an off-peak demand charge, a minimum demand charge, an excess KVAR reactive demand charge, a flat kWh energy charge and a basic service charge.

Q. WHAT IS THE IMPACT OF THE IGS RATE DESIGN ON CURRENT QP AND CIP TOD CUSTOMERS?

A. The table below summarizes the impact of combining the QP and CIP TOD classes and using the CIP TOD rate design under new tariff IGS.

% Impact of IGS Rate Design

	QP	CIP TOD	Total
Secondary	7.0%	NA	7.0%
Primary	8.2%	NA	8.2%
Sub	3.5%	-3.2%	-1.9%
Tran	6.0%	0.3%	1.4%
Total	6.0%	-2.7%	0%

This table is a revenue neutral example of the impacts of the rate design change only. It does not include the rate impacts of the new level of base rates and riders that are proposed in this case.

IV. PJM RIDER

Q. WHAT DOES THE COMPANY PROPOSE TO INCLUDE IN THE PJM RIDER?

A. The Company is proposing to include various PJM Open Access Transmission Tariff (OATT), energy, ancillary and administrative service charges and credits that it incurs from its participation as a load serving entity (LSE) and generation resource owner in the organized wholesale power markets of the PJM RTO.

Q. WHAT SPECIFIC PJM CHARGE AND CREDIT ITEMS IS THE COMPANY PROPOSING TO INCLUDE IN THE PJM RIDER?

A. The Company is proposing to include all of its PJM LSE charges and credits which are currently made up of but not limited to the following items: congestion, Financial Transmission Rights (FTRs), meter corrections, operating reserve, inadvertent energy, economic load response, synchronous condensing, reactive service, black start service, regulation, synchronized reserve, day ahead scheduling reserve, peak hour PJM capacity availability charges, market defaults and administrative services. PJM LSE marginal loss charges and the marginal loss over collection credits will not be included since they are included in the Company's fuel clause.

The Company is also proposing to include the following PJM LSE transmission items: network integration transmission service (NITS) charges, transmission owner scheduling system control and dispatch service (TO) charges, regional transmission expansion plan (RTEP) charges, point-to-point (PTP) transmission service credits, RTO start-up cost recovery charges and expansion cost recovery (ECRC) charges. In addition to the above, the Company also proposes to include any new PJM LSE charges or credits that may arise and be billed to the Company per the PJM tariffs.

Q. IS THE COMPANY PROPOSING TO REMOVE THESE PJM CHARGES AND CREDITS FROM BASE RATES ENTIRELY?

A. No. The Company is proposing to include an adjusted test year level of the applicable PJM charges and credits in base rates. The PJM Rider would then on a monthly basis track the amount of PJM charges and credits above or below the base rate level as discussed further by Company Witness Yoder. The annual net over or under collection of PJM charges would then be collected from or credited to customers through the PJM Rider.

Q. WHY IS THE COMPANY PROPOSING A TRACKING MECHANISM FOR THESE PJM CHARGES AND CREDITS?

A. These PJM charges and credits can have a material financial impact on the Company; the annual level of such charges and credits can vary greatly and they are largely out of the Company's control. This volatility can be attributed to various economic conditions, wholesale power market trends and even tariff changes made by PJM.

Q. ARE THERE ANY ADDITIONAL REASONS FOR INCLUDING THE PJM CHARGES AND CREDITS IN A TRACKING MECHANISM?

A. Yes, there is expected to be a sustained amount of investment to the PJM transmission grid, which will increase transmission charges allocated to Kentucky Power. Tracking these PJM charges and credits via the PJM Rider could potentially reduce the frequency with which Kentucky Power may need to file costly general rate proceedings as these PJM charges and credits change.

Q. WILL ALL KENTUCKY POWER PJM CHARGES AND CREDITS BE INCLUDED IN THE ADJUSTED BASE RATE AMOUNT THAT WILL BE TRACKED BY THE PROPOSED PJM RIDER?

A. No. Only the amount of each charge and credit attributable to retail load, and the resources used to serve retail load, of Kentucky Power would be included. Kentucky Power incurs these charges and credits by acting as an LSE in PJM. Kentucky Power also incurs PJM charges and credits when it makes off system sales (OSS) in PJM. The amount of PJM charges and credits associated with making OSS are currently and will continue to be included in the determination of the Company's System Sales Rider.

Furthermore, per the Stipulation and Settlement Agreement, all Big Sandy plant coal operating costs have been removed from the Company's proposed base rates. This includes the PJM charges and credits from Big Sandy Unit 1 coal operations. The Company is proposing to recover these PJM charges and credits in the BS1OR which I will discuss later in my testimony.

Q. WHAT IS THE PROPOSED LEVEL OF PJM CHARGES AND CREDITS TO BE INCLUDED IN BASE RATES?

A. The adjusted test year Kentucky retail jurisdictional total is $74,856,675. The line item detail behind this figure can be seen in Exhibit AEV 5.

Q. IF THE COMMISSION APPROVES THE PROPOSED PJM RIDER, WHEN WOULD THE COMPANY PROPOSE TO UPDATE THE PJM RIDER RATES?

A. As I previously indicated, the PJM Rider is designed to true-up the actual incurred PJM-related costs relative to the amount in the Company's base rates. As a result, the rider will be set at $0 when the Company's new base rates go into effect. After that it will be trued-up annually. The Company proposes filing the required true-up information beginning no later than March 31, 2016 and by March 31st of each subsequent year.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED RATE DESIGN FOR THE PJM RIDER.

A. The annual net over or under recovery of PJM charges and credits compared to the approved base rate level would be separated into demand and energy costs to be allocated to the customer classes. The demand and energy classifications for each PJM charge can be found in Exhibit AEV 5. The demand revenue requirements for MGS, LGS and IGS will be recovered through an on-peak demand charge. The demand revenue requirements for all other classes will be recovered through the kWh energy charge. The Energy revenue requirements for all classes will be recovered through kWh energy charges. If approved, this PJM Rider would have a first year revenue requirement of $0 since the Company is seeking to include the adjusted test year level of PJM charges and credits in base rates in this proceeding. Exhibit AEV 6 shows the mechanics of the proposed rate design.

V. <u>BIG SANDY UNIT 1 OPERATION RIDER (BS1OR)</u>

Q. WHAT DOES THE COMPANY PROPOSE TO INCLUDE IN THE BS1OR RIDER?

A. In order to comply with the Stipulation and Settlement Agreement, the Company is proposing to remove all Big Sandy Unit 1 operating expenses from base rates in this case and recover them through the BS1OR. This is because Big Sandy Unit 1 will continue to operate as a coal fired generating plant for a period of time before it is converted to a natural gas fired generating plant. As discussed by Company Witness Wohnhas, the

BS1OR will recover all operating expenses of Big Sandy Unit 1 that are not otherwise included in the Company's fuel adjustment clause or the system sales clause.

Q. WHAT IS THE BEGINNING ANNUAL REVENUE REQUIREMENT FOR THE BS1OR RIDER?

A. The total annual revenue requirement for the BS1OR is $18,245,413 on a Kentucky retail jurisdictional basis. The BS1OR revenue requirement and rates will be trued up to actual costs so that customers pay no more or no less than the actual cost to operate Big Sandy Unit 1 as described in the Company's proposed BS1OR tariff.

Q. HOW DID YOU CALCULATE THE BEGINNING ANNUAL REVENUE REQUIREMENT FOR THE BS1OR RIDER?

A. Using the Company's books and records, I performed a cost of service study for Big Sandy Unit 1 that separates Company Witness Yoder's adjustment to remove all Big Sandy operating expenses into those attributable to each of the plant's units. The cost of service study identifies all test year operating expenses attributable to the Big Sandy plant and then either directly assigns or allocates a portion of such expenses to Big Sandy Unit 1. The study results in $12.5 million of test year non-fuel operations and maintenance expense that is attributable to Big Sandy Unit 1. Added to that is an annual level of test year Big Sandy Unit 1 PJM charges and credits totaling $5.65 million of net expense. The total $18.16 million is then grossed up to account for uncollectible accounts expense and the KPSC maintenance fee to produce the total BS1OR revenue requirement of $18.25 million. A summary of the revenue requirement calculations and the rate design for the BS1OR can be found in Company Exhibit AEV 4.

VI. TREATMENT OF TRANSMISSION FUNCTION REVENUES AND EXPENSES

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED TREATMENT OF TRANSMISSION REVENUES AND EXPENSES IN BASE RATES.

A. The Company proposes that its transmission costs should be based upon the charges it incurs as an LSE under PJM's OATT. These costs, which are included in the proposed PJM Rider, would be what Kentucky retail customers pay for transmission service rather than the Company's embedded cost of transmission service. The embedded cost of transmission service and the PJM OATT transmission owner revenues would be removed from the Company's cost of service, the PJM OATT charges are then the remaining cost for transmission service.

Q. PLEASE EXPLAIN WHY IT IS MORE APPROPRIATE FOR TRANSMISSION COSTS TO BE BASED ON THE COMPANY'S PJM OATT CHARGES?

A. Kentucky Power's customers' transmission costs should be based upon the charges under the PJM OATT for a number of reasons:

- Kentucky Power is charged by PJM for transmission service regardless of facility ownership.
- Kentucky Power no longer has exclusive control over its transmission costs because of its membership in PJM. For example, over 92% of the OATT costs that Kentucky Power is charged by PJM for transmission service are based on transmission facilities owned by other companies;
- The annual level of PJM charges and credits can vary significantly;
- Kentucky Power's transmission rates would be comparable to other customers within the AEP Transmission Zone;

- It provides proper separation of Kentucky Power's costs to provide retail service as an LSE from its costs and wholesale revenues as a transmission owner.

Under the Company's proposal, the rates Kentucky Power's customers pay for retail electric service will appropriately reflect the cost of transmission service that Kentucky Power incurs as their LSE.

Q. WHAT IS THE PROPOSED LEVEL OF PJM OATT CHARGES TO BE INCLUDED IN BASE RATES?

A. The adjusted test year Kentucky retail jurisdictional PJM OATT charge is $53,779,456. This amount is included in the $74,856,675 already identified above as the base level to be tracked by the proposed PJM Rider. The line item detail behind this figure can be seen in AEV Exhibit 5.

Q. WHAT IS THE NET EFFECT OF THE COMPANY'S PROPOSED CHANGE TO THE TREATMENT OF TRANSMISSION REVENUES AND EXPENSES?

A. The net effect of the Company's proposed treatment is a reduction in cost to Kentucky ratepayers of $126,908 as can be seen in column 10 of page 1 of Company Witness Stegall's Exhibit JMS-3. It is important to note that this value will change to the extent any other aspect of the Company's requests in this proceeding are modified.

VII. <u>ADJUSTMENTS</u>

Q. WHAT ADJUSTMENTS ARE YOU SPONSORING?

A. I am sponsoring three adjustments that affect non-firm revenues and operating expenses in Section V, Exhibit 2:

1. Adjustment 9 – Remove AEP East Pool Costs/Revenues
2. Adjustment 32 – Adjust Test Year PJM Charges and Credits

3. Adjustment 10 – Adjust Test Year Off System Sales (OSS) Margins

i. <u>Adjustment 9 - Remove AEP East Pool Expenses/Revenues</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE TEST YEAR AEP EAST POOL ACTIVITY.

A. This adjustment removes the revenues and expenses associated with the AEP East Pool Agreement (Pool) that terminated on January 1, 2014 that are reflected in the Company's base rates and were not otherwise removed through another adjustment. Adjustments 7, 10 and 32 also remove Pool related expenses and revenues related to Fuel, PJM and OSS. This adjustment reduces sales for resale by $14,295,833 on a Kentucky retail jurisdictional basis by removing these revenues related to energy sales through the Pool to other Pool member Company. This adjustment also reduces purchased power expense by $24,776,674 on a Kentucky retail jurisdictional basis by removing the expenses associated with Pool capacity and energy purchases.

This adjustment was calculated by using data from Kentucky Power's 4th quarter of 2013 income statement and then applying the proper Kentucky retail jurisdictional factors to arrive at the Kentucky retail jurisdictional adjustment amounts.

ii. <u>Adjustment 32 – Adjust Test Year PJM Charges and Credits</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO TEST YEAR PJM CHARGES AND CREDITS.

A. There are multiple known and measureable items that must be accounted for to adjust the historic test year PJM charges and credits to an appropriate amount for the purpose of setting the Company's new base rates. All of the PJM charge and credit amounts discussed in this section are directly related to serving the Company's internal load obligations which it incurs as a load serving entity (LSE) in PJM, all OSS amounts are accounted for in the Company's System Sales Clause and the OSS margin adjustment discussed later in my testimony. Also, LSE transmission loss PJM charges and credits are accounted for in the Company's fuel adjustment clause and therefore are not included in calculating this adjustment. The following known and measureable changes to the Company's historic test year PJM charges and credits will be discussed in this section:

- Termination of the Pool agreement
- Removal of Big Sandy Unit1 operating expenses from base rates
- Big Sandy Unit 2 retirement
- Replacing Big Sandy Unit 2 MWh that served internal load customers
- Annualizing the non OATT PJM charges and credits
- Annualizing new OATT rates in effect at the end of the test year

Q. PLEASE EXPLAIN THE POOL TERMINATION PORTION OF ADJUSTMENT 32.

A. The former Pool settlement allocated the total Pool PJM charges and credits to the four member operating Company based upon their member load ratio ("MLR"). The MLR was a non-coincident peak demand calculation based on each Pool member's internal load peak on a historic twelve month basis. The MLR allocation was used for all PJM charges and credits except for the PJM OATT charges and credits which are allocated based on the AEP East Transmission Agreement which went into effect in November of 2010. The MLR allocation of PJM charges ended when the Pool Agreement terminated on January 1, 2014. Since the termination of the Pool Agreement, Kentucky Power's PJM charges and credits that had been allocated based on the MLR are being directly assigned to Kentucky Power. This change from an MLR allocation of total East Pool PJM charges and credits to direct assignment of Kentucky Power's PJM charges and credits will impact the overall level of net PJM charges Kentucky Power incurs. I used Kentucky Power's income statement to remove the fourth quarter 2013 Pool related PJM charges and credits from the historic test year. This portion of the total adjustment reduces historic test year PJM charges and credits by $1.18 million.

Q. PLEASE EXPLAIN THE BIG SANDY UNIT 1 PORTION OF ADJUSTMENT 32.

A. In order to comply with the approved stipulation in Case No. 2012-00578, this portion of the total adjustment removes all Big Sandy Unit 1 PJM charges and credits from the test year. Using the Company's books and records along with information provided by PJM's market settlements reporting system, I was able to identify all Big Sandy Unit 1 LSE PJM charges and credits. Removing these items will reduce test year PJM charges and credits by $4.3 million of net expense.

Q. PLEASE EXPLAIN THE BIG SANDY UNIT 2 PORTION OF ADJUSTMENT 32.

A. I repeated the same process discussed above for Big Sandy Unit 1 to remove Big Sandy Unit 2 PJM charges and credits from the test year. This must be done to reflect the known retirement of Big Sandy Unit 2 and comply with the approved stipulation in Case No. 2012-00578. Removing these items will reduce test year PJM charges and credits by $13.37 million of net expense.

Q. PLEASE EXPLAIN THE PORTION OF ADJUSTMENT 32 RELATED TO REPLACING BIG SANDY UNIT 2 GENERATION THAT SERVED INTERNAL LOAD CUSTOMERS.

A. A portion of Big Sandy Unit 2's generation served internal load customers during the test year and the PJM charges associated with that generation have been removed from the test year total as part of Adjustment 32. Because of this, a level of PJM charges must be added back as a substitute for the Big Sandy Unit 2 internal load generation since a cost will be incurred to serve that internal load in PJM. To be more specific, PJM transmission congestion (congestion) and administrative fees are the two items that affect this portion of Adjustment 32. The substitute PJM administrative fees level will equal the amount removed for the internal load portion of Big Sandy Unit 2 because all MWh of generation are charged the same rate by PJM for administrative fee purposes.

The substitute PJM congestion charges related to the internal load portion of Big Sandy Unit 2 however will not equal what was removed for Big Sandy Unit 2 because congestion prices vary by pricing node throughout the PJM RTO. To calculate a substitute amount of congestion charges I used the MWh of the Company's Mitchell and Rockport generation that had been assigned to serve OSS during the test year, since these would logically be the next MWh of Kentucky Power resources that the Company would use to serve its internal load customers, and calculated the average congestion price of those MWh by month and then multiplied the Big Sandy Unit 2 monthly internal load MWh by the calculated average congestion prices. During January and February of 2014 there were not enough OSS MWh from the Company's shares of Mitchell and Rockport to replace the Big Sandy Unit 2 MWh that served internal load customers. For these deficit MWh, I priced the replacement congestion cost using the average monthly day ahead congestion prices for the AEP load zone. Had the Company actually not had Big Sandy Unit 2 and needed to purchase spot market energy from PJM to cover its internal load obligation, the AEP load zone is the pricing point at which the spot market transactions would have settled. The net PJM charges to replace the Big Sandy Unit 2 MWh that served the Company's internal load during the test year would have been $14.68 million of net expense.

Q. PLEASE EXPLAIN THE ANNUALIZATION OF THE NON OATT PJM CHARGES AND CREDITS.

A. The Company's test year total of non OATT PJM charges and credits was a $20.18 million net expense. After the adjustments to remove the Pool and both Big Sandy Units, along with the adjustment to replace the internal load PJM charges of Big Sandy Unit 2, the new adjusted total for the PJM non OATT charges and credits is $16.02 million (20.18 – 1.18 - 4.3 - 13.3 + 14.68 = 16.02). The $16.02 million represents Kentucky Power's adjusted, stand-alone total of non OATT PJM charges and credits for January through September of 2014. After annualizing this amount to reflect a full 12 months instead of 9, the new adjusted total of non OATT PJM charges and credits is $21.38 million of net expense.

Q. PLEASE EXPLAIN THE PORTION OF ADJUSTMENT 32 RELATED TO ANNUALIZING THE OATT RATES IN EFFECT AT THE END OF THE TEST YEAR.

A. Each year on July 1st new OATT rates go into effect. I calculated the Company's PJM OATT charges based on the new rates that began on July 1, 2014 and will be in effect through June 30, 2015. The resulting level of PJM OATT charges is $53.78 million which is $6.41 million higher than the test year total of $47.37 million.

Q. WHAT IS THE NET IMPACT OF ADJUSTMENT 32?

A. After comparing the adjusted total PJM charges and credits to the test year amount, the net impact of this adjustment is a $7.60 million increase in expense. The Kentucky retail jurisdictional adjustment is then a $7.58 million increase in expense.

iii. <u>Adjustment 10 – Adjust Test Year Off System Sales (OSS) Margins</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR OSS MARGINS.

A. The purpose of this adjustment is to account for several known and measurable changes to the Company's historic test year OSS margins and calculate a more appropriate OSS margin amount for setting base rates. This is necessary because the Company's historic test year OSS margins of $76.09 million are in no way representative of the level of margins the Company will experience when its new base rates resulting from this case go into effect. The historic level of OSS margins cannot be used for rate making in this proceeding because they include 3 months of margins from the Pool which no longer exists, margins from Big Sandy Unit 2 which is retiring no later than May 31, 2015, a higher level of margins resulting from the Company owning a fifty percent share of the Mitchell plant while Big Sandy 2 was still in operation, and finally the historic test year contains extreme weather and pricing events in January and February of 2014.

Q. HOW WAS THIS ADJUSTMENT CALCULATED?

A. The total adjustment to OSS margins was calculated in steps. The first step was to separate the FERC accounts that make up the Company's System Sales Clause into those that account for PJM energy sales margins and those that account for other OSS margin items. FERC account 4470089 is used to record to the margins from sales of excess energy into the PJM day ahead and balancing energy markets. Only the energy portion of the margins are recorded in this account, all other PJM charges associated with energy sales are recorded in other System Sales Clause FERC accounts. The next step was to remove the Pool OSS margins from the historic test year totals. This was done by removing the income statement amounts for the fourth quarter of 2013 from the test year total of OSS margins. This portion of the adjustment reduces test year OSS margins by roughly $1.34 million.

The OSS PJM charges and credits associated with Big Sandy Unit 2 were then removed from the test year level of OSS margins. Using the Company's books and records, the portion of PJM charges and credits from Big Sandy Unit 2 that were allocated to OSS were identified and then removed from the test year amount of OSS margins because Big Sandy Unit 2 will retire on May 31, 2015. This adjustment increases test year OSS margins by roughly $14.27 million. Also associated with the retirement of Big Sandy Unit 2 is the LSE/OSS PJM charge re-class. The OSS impact of this adjustment is the opposite side of the same adjustment to the test year PJM charges and credits that are related to Kentucky Power's internal load and are included in base rates. This portion of the total OSS margin adjustment increases test year OSS margins by $15.97 million.

The Kentucky Power test year OSS margins for items other than the PJM energy sales in account 4470089 were negative $36.24 million, combined with the three steps of the total adjustment discussed above produces an adjusted test year OSS margin amount (excluding PJM energy sales margins) of $7.34 million (-36.24 – 1.34 +14.27 + 15.97 = -7.34) which represents an adjusted January – September 2014 total. Annualizing this amount increases the negative $7.34 million to negative $9.79 million (7.34 / (9/12) = 9.79).

Q. PLEASE DESCRIBE THE COMPANY'S METHODOLOGY FOR CALCULATING THE PJM ENERGY SALES PORTION OF TOTAL (ACCOUNT 4470089) GOING LEVEL OSS MARGINS.

A. Due to three known differences in the generation resources which the Company will have in the rate year vs the test year, the actual level of off-system sales (OSS) margins received in the test year by the Company is not a reasonable estimate of a going level amount of OSS margins. These changes are that Big Sandy 2 will be retired prior to the rate year, the AEP Pool has been terminated, and Mitchell 1 and 2 will be owned for 12 months of the rate year instead of 9 months in the test year. In order to support an adjustment to test year OSS margins, I oversaw the preparation of a model which emulated AEP's current resource stacking methodology to estimate what margins would have been in the test year with the new resource mix.

In addition to the resource mix change, other major assumptions embedded in the OSS margin model are as follows:

1. All PJM market purchases during the test year were ignored. Purchases were made either to serve internal load when the output of the available generation was below load, which would not have generated OSS, or because of hourly differences between day ahead load and generation schedules submitted to PJM and real time load and generation. Because of the different mix of resources described above, the hourly differences between day ahead schedules and real time generation and load would

have been different from what actually occurred in the test year, and therefore it would not be valid to include purchases resulting from these differences in the model.

2. The Company's resources were restacked hourly as they are currently through AEP's hourly settlements process, with most expensive incremental cost units assigned to off-system sales down to the unit minimums.
3. Internal load was normalized for weather, to match the load used in the Company's weather normalization revenue adjustment, as described by Company witness Stegall.
4. Any hourly resources in excess of load were sold into the PJM market at Day Ahead spot market energy component of the PJM market price, except during January and February of 2014, for reasons I will discuss.

All of the other components of OSS margins other than spot market energy margin, including congestion and losses, were recomputed using the same resource mix assumption and should be deducted from spot market energy margin to arrive at the total going level estimate of OSS margin.

Q. DID YOU ADJUST FOR THE IMPACT OF THE EXTREME COLD WEATHER OF THIS PAST WINTER IN YOUR MARGIN CALCULATION?

A. Yes. During the Polar Vortex and other extreme cold weather periods of January and February, 2014, market prices and internal load reached unprecedented levels for large blocks of time. During January and February of the six years from 2008 to 2013 the spot market energy component of the PJM Day Ahead market price averaged over $100 (all prices in $/MWh) in only five days and the highest single daily average was $122.65. In contrast, during this past January and February, there were 17 days when the daily average was over $100. Nine of those days averaged over $200 and the highest daily average was $544.65. The daily average spot market energy price during January and February of 2008-2013 was $47.35, while 2014's average was $97.17.

These winter prices are clearly not representative of prices prior to the test year and should not be reflected in an OSS margin credit in customer rates. As a result the Company elected to model those months by setting the spot market energy price at the 2008-2013 average of $47.35 in every hour.

These prices were driven up because load across PJM, including Kentucky Power's load, was higher than normal due to the extreme cold weather, resulting in higher cost generators being dispatched to serve the load by PJM. The higher internal load reduced the Company's ability to make OSS. The residential portion of these high loads was reduced to normal levels through a normalization adjustment, which increased the amount of generation available to make OSS and the resulting OSS margins.

Q. WHY DID YOU CHOOSE TO USE THE AVERAGE OF 2008-2013 TO NORMALIZE THE ENERGY PRICING DURING JANUARY AND FEBRUARY OF 2014?

A. I chose the 2008-2013 period for my average of January and February prices because it is a long enough period to cover a variety of PJM market conditions and overall economic and weather conditions, without going so far back in time to when economic and PJM market conditions are less likely to be representative of current or future conditions.

Q. WHAT LEVEL OF PJM ENERGY SALES MARGINS RESULTED FROM THIS ANALYSIS?

A. The analysis yielded an estimate of going level spot market energy margins for the total company of $24.28 million vs a test year value of $112.3 million (recorded in FERC account 4470089), resulting in a downward adjustment of $88.0 million at the total company level.

Q. PLEASE SUMMARIZE THE TOTAL IMPACT OF ADJUSTMENT NUMBER 10.

A. When the $24.28 million is added to the negative $9.79 million of negative OSS margins discussed earlier in this section, the Kentucky Power adjusted OSS margin total is $14.5 million, which results in a total adjustment to test year OSS margins of $61.59 million ($76.09 – $14.5 = $61.59) Lastly, this amount is multiplied the Kentucky retail jurisdictional factor to arrive at the final OSS margin adjustment of $61,585,035, which is a reduction to test year OSS margins. A summary of these calculations can be seen in Company Exhibit AEV 7. The resulting going level amount of OSS margin is estimated to be $14.3 million. This is the amount the Company is proposing to credit to customers in base rates. It should be noted that if the Commission were to make changes to how the Company allocates no load or other fuel costs, this amount would need to be revised accordingly.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes.

KPCo Kentucky Retail Jurisdiction
Base Rate Revenue Target Summary

	From CCOS	Total Retail	RS	SGS	Total MGS	Total LGS	Total QP	Total CIP-TOD	Total IGS (QP & CIP-TOD)	MW	OL	SL
a	Demand	$ 186,439,680	$ 76,396,686	$ 4,569,088	$ 18,095,605	$ 22,797,382	$ 19,692,588	$ 44,700,977	$ 64,393,565	$ 103,875	$ 64,535	$ 18,945
b	Energy	$ 226,505,780	$ 77,357,442	$ 5,219,426	$ 18,951,622	$ 26,244,196	$ 26,587,649	$ 70,591,022	$ 97,178,671	$ 142,805	$ 1,118,464	$ 293,154
c	Dist Primary	$ 82,654,958	$ 47,203,012	$ 3,227,757	$ 12,362,190	$ 14,076,296	$ 5,711,912	$ -	$ 5,711,912	$ 73,792	$ -	$ -
d	Dist Secondary	$ 34,625,386	$ 21,937,720	$ 2,049,932	$ 5,444,132	$ 4,548,249	$ 128,427	$ -	$ 128,427	$ 24,925	$ 381,203	$ 110,798
e	Customer	$ 25,544,050	$ 12,648,538	$ 3,762,175	$ 1,553,231	$ 568,569	$ 307,323	$ 117,463	$ 424,786	$ 1,760	$ 5,598,297	$ 986,695
f= sum a-e	TOTAL	$ 555,769,854	$ 235,543,397	$ 18,828,379	$ 56,406,779	$ 68,234,690	$ 52,427,899	$ 115,409,462	$ 167,837,361	$ 347,156	$ 7,162,499	$ 1,409,592
	Adjustments											
g	Less Fuel Clause	$ 13,251,150	$ 4,613,241	$ 290,984	$ 1,048,409	$ 1,443,818	$ 1,555,897	$ 4,197,367	$ 5,753,265	$ 7,887	$ 76,829	$ 16,717
h	HEAP	$ 249,045	$ 249,045									
i	Facilities Charge	$ 150,000					$ 150,000					
	Base Rate Revenue Targets											
j=a	Demand	$ 186,439,680	$ 76,396,686	$ 4,569,088	$ 18,095,605	$ 22,797,382	$ 19,692,588	$ 44,700,977	$ 64,393,565	$ 103,875	$ 64,535	$ 18,945
k=b-g	Energy	$ 213,254,630	$ 72,744,201	$ 4,928,442	$ 17,903,213	$ 24,800,378	$ 25,031,752	$ 66,393,655	$ 91,425,406	$ 134,918	$ 1,041,635	$ 276,437
l=c-i	Dist Primary	$ 82,504,958	$ 47,203,012	$ 3,227,757	$ 12,362,190	$ 14,076,296	$ 5,561,912	$ -	$ 5,561,912	$ 73,792	$ -	$ -
m=d	Dist Secondary	$ 34,625,386	$ 21,937,720	$ 2,049,932	$ 5,444,132	$ 4,548,249	$ 128,427	$ -	$ 128,427	$ 24,925	$ 381,203	$ 110,798
n=e-h	Customer	$ 25,295,005	$ 12,399,493	$ 3,762,175	$ 1,553,231	$ 568,569	$ 307,323	$ 117,463	$ 424,786	$ 1,760	$ 5,598,297	$ 986,695
o=sum j-n		$ 542,119,659	$ 230,681,111	$ 18,537,394	$ 55,358,371	$ 66,790,874	$ 50,722,002	$ 111,212,095	$ 161,934,096	$ 339,270	$ 7,085,670	$ 1,392,875

Full Cost Basic Service Charge Calculation
Fixed Cost of Distribution Plant Method
Kentucky

Residential					
		Dist. Primary Demand	**Dist. Secondary Demand**	**Distribution Customer Services & Accounts**	**Distribution Total**
Distribution Revenue Requirement (CCOS)		$47,203,012	$21,937,720	$12,399,493	$ 81,540,225
Fixed Distribution Plant Allocation Factors		78%	77%	100%	
Fixed Distribution Plant Revenue Requirement		$ 36,819,599	$ 16,995,464	$12,399,493	$ 66,214,557
Residential Bills					
	1,660,309	22.18	10.24	7.47	
	1,658,209	RS			
	2,100	RSTOD			
Full Cost Basic Service Charge		**$39.88**	**per customer per month**		

Small General Service (SGS)					
		Dist. Primary Demand	**Dist. Secondary Demand**	**Distribution Customer Services & Accounts**	**Distribution Total**
Distribution Revenue Requirement		$ 3,227,757	$ 2,049,932	$ 3,762,175	$ 9,039,864
Fixed Distribution Plant Allocation Factors		78%	77%	100%	
Fixed Distribution Plant Revenue Requirement		$ 2,517,736	$ 1,588,112	$ 3,762,175	$ 7,868,022
SGS Bills					
	289,172	8.71	5.49	13.01	
	271,566	Standard			
	17,594	Non-metered			
	12	LM TOD			
Full Cost Basic Service Charge		**$ 27.21**	**per customer per month**		

Kentucky
Distribution Plant Study
Test Year Ending September 30, 2014

Property Class	Property Class Description	Classification	Fixed Cost Distribution Plant Study: Primary Voltage	Secondary Voltage	Total	Primary $	Secondary $	Total Plant $
364	Poles & Towers	Demand	6.8%	10.6%	17.4%	$ 10,156,537	$ 15,844,988	$ 26,001,525
		Customer	50.2%	32.4%	82.6%	$ 75,130,319	$ 48,500,671	$ 123,630,990
365	OH Conductors	Demand	19.4%	10.6%	30.1%	$ 31,393,719	$ 17,195,756	$ 48,589,475
		Customer	43.4%	26.5%	69.9%	$ 70,122,353	$ 42,793,814	$ 112,916,166
367	UG Conductors	Demand	24.3%	15.9%	40.2%	$ 1,985,814	$ 1,296,470	$ 3,282,284
		Customer	40.2%	19.5%	59.8%	$ 3,280,443	$ 1,594,641	$ 4,875,084
368	Transformers	Demand	3.3%	13.4%	16.7%	$ 4,086,271	$ 16,380,444	$ 20,466,715
		Customer	16.6%	66.6%	83.3%	$ 20,335,787	$ 81,519,121	$ 101,854,908
			Total Dist Plant			$ 216,491,242	$ 225,125,904	$ 441,617,147
			Customer Total			$ 168,868,902	$ 174,408,247	$ 343,277,148
			Fixed Allocation Factor for Rate Design			78%	77%	78%

Kentucky Power
Account 364 - Poles
Test Period Ending September 30, 2014

Height	Class	Pole Usage	Number of poles	Primary Connections	Secondary Connections	cost per pole	Pri Investment	Sec Investment	Total Investment
0	0	PO	138	843	0	762	$105,156	$0	$105,156
0	0	PS	44	265	174	762	$20,239	$13,289	$33,528
0	0	PT	2	8	2	762	$1,219	$305	$1,524
0	0	PT	171	767	382	762	$86,981	$43,321	$130,302
0	0	SO	306	0	1018	762	$0	$233,172	$233,172
0	2	PO	3	28	0	762	$2,286	$0	$2,286
0	2	PT	2	12	6	762	$1,016	$508	$1,524
0	3	PO	1	6	0	762	$762	$0	$762
0	3	SO	1	0	3	762	$0	$762	$762
0	4	PO	8	40	0	762	$6,096	$0	$6,096
0	4	PT	9	41	13	762	$5,207	$1,651	$6,858
0	4	SO	10	0	30	762	$0	$7,620	$7,620
0	5	PO	12	54	0	762	$9,144	$0	$9,144
0	5	PS	1	6	6	762	$381	$381	$762
0	5	PT	18	67	38	762	$8,752	$4,964	$13,716
0	5	SO	40	0	147	762	$0	$30,480	$30,480
0	6	PO	9	46	0	762	$6,858	$0	$6,858
0	6	PS	3	10	15	762	$914	$1,372	$2,286
0	6	PT	8	20	29	762	$2,488	$3,608	$6,096
0	6	SO	13	0	39	762	$0	$9,906	$9,906
0	7	PO	5	22	0	762	$3,810	$0	$3,810
0	7	PS	2	10	7	762	$896	$628	$1,524
0	N/A	PO	1	8	0	762	$762	$0	$762
0	N/A	PS	1	8	8	762	$381	$381	$762
0	N/A	PT	4	31	26	762	$1,658	$1,390	$3,048
0	N/A	SO	13	0	60	762	$0	$9,906	$9,906
0	Unknown	PO	1856	11307	0	762	$1,414,272	$0	$1,414,272
0	Unknown	PS	408	2487	1750	762	$182,487	$128,409	$310,896
0	Unknown	PT	1965	9051	4726	762	$983,693	$513,637	$1,497,330
0	Unknown	SO	2399	0	8251	762	$0	$1,828,038	$1,828,038
10	4	PT	1	2	0	518	$518	$0	$518
17	N/A	SO	10	0	28	518	$0	$5,180	$5,180
20	0	PO	1	8	0	508	$508	$0	$508
20	0	SO	1	0	3	508	$0	$508	$508
20	2	PT	1	8	3	518	$377	$141	$518
20	3	PS	1	8	6	518	$296	$222	$518
20	4	PT	1	8	8	508	$254	$254	$508
20	4	SO	1	0	3	518	$0	$518	$518
20	6	SO	3	0	15	518	$0	$1,554	$1,554
20	7	PO	2	16	0	508	$1,016	$0	$1,016
20	7	PS	1	10	9	508	$267	$241	$508
20	7	SO	6	0	22	508	$0	$3,048	$3,048
20	N/A	SO	1	0	8	508	$0	$508	$508
20	Unknown	PO	1	8	0	508	$508	$0	$508
24	N/A	SO	2	0	6	508	$0	$1,016	$1,016
25	0	PT	1	4	6	508	$203	$305	$508
25	0	SO	3	0	15	508	$0	$1,524	$1,524
25	1	PS	1	9	9	518	$259	$259	$518
25	1	PT	1	8	3	518	$377	$141	$518
25	2	PS	1	6	8	518	$222	$296	$518
25	2	SO	4	0	11	518	$0	$2,072	$2,072
25	4	PS	1	4	8	518	$173	$345	$518
25	4	PT	2	14	0	518	$1,036	$0	$1,036
25	4	SO	3	0	9	518	$0	$1,554	$1,554
25	5	PO	2	15	0	518	$1,036	$0	$1,036
25	5	PS	1	4	9	518	$159	$359	$518
25	5	SO	39	0	148	518	$0	$20,202	$20,202
25	6	PO	1	4	0	518	$518	$0	$518
25	6	PS	1	10	6	518	$324	$194	$518

Height	Class	Pole Usage	Number of poles	Primary Connections	Secondary Connections	cost per pole	Pri Investment	Sec Investment	Total Investment
25	6	SO	17	0	56	518	$0	$8,806	$8,806
25	7	PO	3	14	0	508	$1,524	$0	$1,524
25	7	PS	1	11	12	508	$243	$265	$508
25	7	PT	1	3	12	508	$102	$406	$508
25	7	SO	33	0	129	508	$0	$16,764	$16,764
25	N/A	PO	1	4	0	508	$508	$0	$508
25	N/A	SO	1	0	4	508	$0	$508	$508
25	Unknown	PO	3	10	0	508	$1,524	$0	$1,524
25	Unknown	PT	2	12	3	508	$813	$203	$1,016
25	Unknown	SO	1	0	2	508	$0	$508	$508
30	0	PO	5	22	0	514	$2,570	$0	$2,570
30	0	PT	1	7	0	514	$514	$0	$514
30	0	SO	24	0	84	514	$0	$12,336	$12,336
30	1	PT	1	10	9	614	$323	$291	$614
30	1	SO	1	0	2	614	$0	$614	$614
30	2	PO	3	24	0	614	$1,842	$0	$1,842
30	2	PS	2	10	12	614	$558	$670	$1,228
30	2	SO	9	0	29	614	$0	$5,526	$5,526
30	3	PO	5	28	0	614	$3,070	$0	$3,070
30	3	PS	1	2	6	614	$154	$461	$614
30	3	PT	2	6	13	614	$388	$840	$1,228
30	3	SO	15	0	69	614	$0	$9,210	$9,210
30	4	PO	28	129	0	582	$16,296	$0	$16,296
30	4	PS	20	95	80	582	$6,319	$5,321	$11,640
30	4	PT	27	77	72	582	$8,121	$7,593	$15,714
30	4	SO	311	0	1206	582	$0	$181,002	$181,002
30	5	PO	165	775	0	555	$91,575	$0	$91,575
30	5	PS	42	198	180	555	$12,210	$11,100	$23,310
30	5	PT	129	434	332	555	$40,564	$31,031	$71,595
30	5	SO	935	0	3269	555	$0	$518,925	$518,925
30	6	PO	543	2525	0	533	$289,419	$0	$289,419
30	6	PS	217	1036	843	533	$63,771	$51,890	$115,661
30	6	PT	490	1778	1200	533	$155,930	$105,240	$261,170
30	6	SO	31641	0	96188	533	$0	$16,864,653	$16,864,653
30	7	PO	349	1593	0	514	$179,386	$0	$179,386
30	7	PS	24	117	112	514	$6,303	$6,033	$12,336
30	7	PT	72	274	207	514	$21,081	$15,927	$37,008
30	7	SO	1792	0	4771	514	$0	$921,088	$921,088
30	8	PO	23	96	0	514	$11,822	$0	$11,822
30	8	PS	2	7	8	514	$480	$548	$1,028
30	8	PT	1	4	0	514	$514	$0	$514
30	8	SO	12	0	40	514	$0	$6,168	$6,168
30	9	SO	2	0	6	514	$0	$1,028	$1,028
30	N/A	SO	4	0	11	514	$0	$2,056	$2,056
30	Unknown	PO	5	23	0	514	$2,570	$0	$2,570
30	Unknown	PT	2	10	9	514	$541	$487	$1,028
30	Unknown	SO	31	0	129	514	$0	$15,934	$15,934
32	N/A	SO	9	0	47	594	$0	$5,346	$5,346
33	Unknown	PS	1	8	8	594	$297	$297	$594
33	Unknown	SO	7	0	44	594	$0	$4,158	$4,158
35	0	PO	4	18	0	594	$2,376	$0	$2,376
35	0	PT	6	27	26	594	$1,816	$1,748	$3,564
35	0	SO	5	0	15	594	$0	$2,970	$2,970
35	1	PO	3	18	0	747	$2,241	$0	$2,241
35	1	PT	3	14	9	747	$1,364	$877	$2,241
35	1	SO	11	0	43	747	$0	$8,217	$8,217
35	2	PO	79	453	0	747	$59,013	$0	$59,013
35	2	PS	41	204	182	747	$16,186	$14,441	$30,627
35	2	PT	114	394	256	747	$51,619	$33,539	$85,158
35	2	SO	212	0	816	747	$0	$158,364	$158,364
35	3	PO	23	165	0	701	$16,123	$0	$16,123
35	3	PS	5	24	31	701	$1,529	$1,976	$3,505
35	3	PT	22	88	68	701	$8,700	$6,722	$15,422

Height	Class	Pole Usage	Number of poles	Primary Connections	Secondary Connections	cost per pole	Pri Investment	Sec Investment	Total Investment
35	3	SO	32	0	118	701	$0	$22,432	$22,432
35	4	PO	632	3693	0	660	$417,120	$0	$417,120
35	4	PS	212	1122	1031	660	$72,917	$67,003	$139,920
35	4	PT	947	3482	2428	660	$368,244	$256,776	$625,020
35	4	SO	2020	0	7341	660	$0	$1,333,200	$1,333,200
35	5	PO	4207	20802	0	615	$2,587,305	$0	$2,587,305
35	5	PS	1142	4930	5009	615	$348,374	$353,956	$702,330
35	5	PT	5548	19328	12906	615	$2,045,899	$1,366,121	$3,412,020
35	5	SO	20000	0	67795	615	$0	$12,300,000	$12,300,000
35	6	PO	2809	13193	0	594	$1,668,546	$0	$1,668,546
35	6	PS	542	2371	2265	594	$164,655	$157,293	$321,948
35	6	PT	2039	8142	4977	594	$751,682	$459,484	$1,211,166
35	6	SO	2171	0	7847	594	$0	$1,289,574	$1,289,574
35	7	PO	943	4359	0	594	$560,142	$0	$560,142
35	7	PS	154	689	640	594	$47,424	$44,052	$91,476
35	7	PT	406	1831	1112	594	$150,041	$91,123	$241,164
35	7	SO	232	0	957	594	$0	$137,808	$137,808
35	8	PO	1	4	0	594	$594	$0	$594
35	8	PS	1	4	6	594	$238	$356	$594
35	8	PT	1	8	0	594	$594	$0	$594
35	9	PT	1	2	0	594	$594	$0	$594
35	N/A	PO	1	8	0	594	$594	$0	$594
35	N/A	PT	3	17	14	594	$977	$805	$1,782
35	N/A	SO	14	0	37	594	$0	$8,316	$8,316
35	Unknown	PO	1	4	0	594	$594	$0	$594
35	Unknown	PS	1	8	6	594	$339	$255	$594
35	Unknown	PT	3	8	3	594	$1,296	$486	$1,782
35	Unknown	SO	6	0	26	594	$0	$3,564	$3,564
40	0	PO	3	22	0	712	$2,136	$0	$2,136
40	0	PS	3	24	9	712	$1,553	$583	$2,136
40	0	PT	14	97	58	712	$6,238	$3,730	$9,968
40	0	SO	3	0	6	712	$0	$2,136	$2,136
40	1	PO	4	32	0	788	$3,152	$0	$3,152
40	1	PS	9	51	42	788	$3,889	$3,203	$7,092
40	1	PT	9	41	31	788	$4,039	$3,054	$7,092
40	1	SO	1	0	10	788	$0	$788	$788
40	2	PO	974	6845	0	869	$846,406	$0	$846,406
40	2	PS	243	1633	1232	869	$120,362	$90,805	$211,167
40	2	PT	1341	6388	3654	869	$741,299	$424,030	$1,165,329
40	2	SO	137	0	620	869	$0	$119,053	$119,053
40	3	PO	114	682	0	812	$92,568	$0	$92,568
40	3	PS	28	166	167	812	$11,334	$11,402	$22,736
40	3	PT	111	538	333	812	$55,673	$34,459	$90,132
40	3	SO	14	0	53	812	$0	$11,368	$11,368
40	4	PO	9037	50200	0	762	$6,886,194	$0	$6,886,194
40	4	PS	1933	10541	8392	762	$820,067	$652,879	$1,472,946
40	4	PT	15867	59787	34920	762	$7,632,635	$4,458,019	$12,090,654
40	4	SO	1875	0	7215	762	$0	$1,428,750	$1,428,750
40	5	PO	6910	34105	0	712	$4,919,920	$0	$4,919,920
40	5	PS	1777	8882	7613	712	$681,280	$583,944	$1,265,224
40	5	PT	11216	40953	23168	712	$5,100,391	$2,885,401	$7,985,792
40	5	SO	1987	0	7452	712	$0	$1,414,744	$1,414,744
40	6	PO	498	2572	0	712	$354,576	$0	$354,576
40	6	PS	151	766	666	712	$57,510	$50,002	$107,512
40	6	PT	511	2467	1550	712	$223,444	$140,388	$363,832
40	6	SO	115	0	465	712	$0	$81,880	$81,880
40	7	PO	49	262	0	712	$34,888	$0	$34,888
40	7	PS	14	71	60	712	$5,403	$4,565	$9,968
40	7	PT	21	97	52	712	$9,734	$5,218	$14,952
40	7	SO	5	0	20	712	$0	$3,560	$3,560
40	N/A	PO	3	27	0	762	$2,286	$0	$2,286
40	N/A	PS	12	104	79	762	$5,197	$3,947	$9,144
40	N/A	PT	4	16	12	762	$1,742	$1,306	$3,048

Height	Class	Pole Usage	Number of poles	Primary Connections	Secondary Connections	cost per pole	Pri Investment	Sec Investment	Total Investment
40	N/A	SO	159	0	827	762	$0	$121,158	$121,158
40	Unknown	PO	12	71	0	762	$9,144	$0	$9,144
40	Unknown	PS	1	2	3	762	$305	$457	$762
40	Unknown	PT	12	59	25	762	$6,423	$2,721	$9,144
40	Unknown	SO	7	0	29	762	$0	$5,334	$5,334
45	0	PO	7	54	0	820	$5,740	$0	$5,740
45	0	PS	44	435	314	820	$20,954	$15,126	$36,080
45	0	PT	28	214	185	820	$12,314	$10,646	$22,960
45	0	SO	1	0	6	820	$0	$820	$820
45	1	PO	8	67	0	1087	$8,696	$0	$8,696
45	1	PS	4	27	17	1087	$2,668	$1,680	$4,348
45	1	PT	24	146	56	1087	$18,856	$7,232	$26,088
45	2	PO	2264	17411	0	1012	$2,291,168	$0	$2,291,168
45	2	PS	620	5091	2786	1012	$405,522	$221,918	$627,440
45	2	PT	2747	16192	7876	1012	$1,870,250	$909,714	$2,779,964
45	2	SO	69	0	274	1012	$0	$69,828	$69,828
45	3	PO	196	1423	0	940	$184,240	$0	$184,240
45	3	PS	46	355	214	940	$26,978	$16,262	$43,240
45	3	PT	174	954	510	940	$106,582	$56,978	$163,560
45	3	SO	12	0	57	940	$0	$11,280	$11,280
45	4	PO	9936	58788	0	877	$8,713,872	$0	$8,713,872
45	4	PS	2117	13617	8793	877	$1,128,132	$728,477	$1,856,609
45	4	PT	16856	71986	36230	877	$9,833,558	$4,949,154	$14,782,712
45	4	SO	507	0	1967	877	$0	$444,639	$444,639
45	5	PO	1247	6873	0	820	$1,022,540	$0	$1,022,540
45	5	PS	328	2000	1491	820	$154,088	$114,872	$268,960
45	5	PT	2290	10186	5546	820	$1,215,819	$661,981	$1,877,800
45	5	SO	180	0	755	820	$0	$147,600	$147,600
45	6	PO	43	249	0	820	$35,260	$0	$35,260
45	6	PS	15	70	61	820	$6,573	$5,727	$12,300
45	6	PT	71	361	195	820	$37,801	$20,419	$58,220
45	6	SO	8	0	22	820	$0	$6,560	$6,560
45	7	PO	1	8	0	820	$820	$0	$820
45	7	PS	3	14	17	820	$1,111	$1,349	$2,460
45	7	PT	10	53	42	820	$4,575	$3,625	$8,200
45	7	SO	2	0	7	820	$0	$1,640	$1,640
45	N/A	PS	3	23	26	820	$1,155	$1,305	$2,460
45	N/A	SO	2	0	14	820	$0	$1,640	$1,640
45	Unknown	PO	6	32	0	820	$4,920	$0	$4,920
45	Unknown	PS	2	20	11	820	$1,058	$582	$1,640
45	Unknown	PT	8	55	21	820	$4,747	$1,813	$6,560
45	Unknown	SO	1	0	3	820	$0	$820	$820
50	0	PS	2	28	19	1149	$1,369	$929	$2,298
50	1	PO	9	78	0	1247	$11,223	$0	$11,223
50	1	PS	1	8	2	1247	$998	$249	$1,247
50	1	PT	20	157	41	1247	$19,776	$5,164	$24,940
50	2	PO	2961	23614	0	1149	$3,402,189	$0	$3,402,189
50	2	PS	789	6958	3396	1149	$609,219	$297,342	$906,561
50	2	PT	3419	24114	9571	1149	$2,812,236	$1,116,195	$3,928,431
50	2	SO	77	0	286	1149	$0	$88,473	$88,473
50	3	PO	435	2797	0	1068	$464,580	$0	$464,580
50	3	PS	88	684	331	1068	$63,335	$30,649	$93,984
50	3	PT	577	3161	1487	1068	$419,088	$197,148	$616,236
50	3	SO	14	0	43	1068	$0	$14,952	$14,952
50	4	PO	1039	7348	0	994	$1,032,766	$0	$1,032,766
50	4	PS	273	2107	1135	994	$176,360	$95,002	$271,362
50	4	PT	1651	9658	4162	994	$1,146,866	$494,228	$1,641,094
50	4	SO	42	0	164	994	$0	$41,748	$41,748
50	5	PO	9	62	0	952	$8,568	$0	$8,568
50	5	PS	8	48	42	952	$4,062	$3,554	$7,616
50	5	PT	24	137	78	952	$14,559	$8,289	$22,848
50	5	SO	1	0	6	952	$0	$952	$952
50	6	PO	4	32	0	952	$3,808	$0	$3,808

Height	Class	Pole Usage	Number of poles	Primary Connections	Secondary Connections	cost per pole	Pri Investment	Sec Investment	Total Investment
50	6	PT	2	18	3	952	$1,632	$272	$1,904
50	6	SO	2	0	4	952	$0	$1,904	$1,904
50	7	PT	2	12	3	952	$1,523	$381	$1,904
50	7	SO	1	0	2	952	$0	$952	$952
50	9	PO	1	4	0	1149	$1,149	$0	$1,149
50	N/A	PO	1	9	0	1149	$1,149	$0	$1,149
50	N/A	PS	1	3	8	1149	$313	$836	$1,149
50	N/A	PT	1	8	0	1149	$1,149	$0	$1,149
50	Unknown	PO	1	4	0	1149	$1,149	$0	$1,149
55	0	PT	3	17	16	1276	$1,972	$1,856	$3,828
55	0	SO	4	0	40	1276	$0	$5,104	$5,104
55	1	PO	14	140	0	1395	$19,530	$0	$19,530
55	1	PS	1	8	8	1395	$698	$698	$1,395
55	1	PT	12	102	58	1395	$10,672	$6,068	$16,740
55	1	SO	1	0	8	1276	$0	$1,276	$1,276
55	2	PO	1500	13068	0	1276	$1,914,000	$0	$1,914,000
55	2	PS	392	3648	1568	1276	$349,828	$150,364	$500,192
55	2	PT	1567	12629	4680	1276	$1,458,870	$540,622	$1,999,492
55	2	SO	24	0	84	1276	$0	$30,624	$30,624
55	3	PO	50	340	0	1196	$59,800	$0	$59,800
55	3	PS	21	156	87	1196	$16,124	$8,992	$25,116
55	3	PT	80	507	213	1196	$67,375	$28,305	$95,680
55	3	SO	5	0	17	1196	$0	$5,980	$5,980
55	4	PO	102	708	0	1100	$112,200	$0	$112,200
55	4	PS	26	192	122	1100	$17,488	$11,112	$28,600
55	4	PT	121	770	328	1100	$93,340	$39,760	$133,100
55	4	SO	9	0	32	1100	$0	$9,900	$9,900
55	5	PO	3	18	0	1100	$3,300	$0	$3,300
55	5	PS	6	50	33	1100	$3,976	$2,624	$6,600
55	5	PT	6	42	19	1100	$4,544	$2,056	$6,600
55	5	SO	3	0	7	1100	$0	$3,300	$3,300
55	6	PO	2	18	0	1100	$2,200	$0	$2,200
55	Unknown	PO	2	14	0	1276	$2,552	$0	$2,552
60	0	PS	1	15	3	1472	$1,227	$245	$1,472
60	1	PO	2	18	0	1630	$3,260	$0	$3,260
60	1	PT	5	60	20	1630	$6,113	$2,038	$8,150
60	2	PO	375	3350	0	1472	$552,000	$0	$552,000
60	2	PS	108	1059	479	1472	$109,464	$49,512	$158,976
60	2	PT	320	2923	1018	1472	$349,366	$121,674	$471,040
60	2	SO	2	0	5	1472	$0	$2,944	$2,944
60	3	PO	18	142	0	1374	$24,732	$0	$24,732
60	3	PS	3	24	8	1374	$3,092	$1,031	$4,122
60	3	PT	18	134	49	1374	$18,110	$6,622	$24,732
60	3	SO	3	0	10	1374	$0	$4,122	$4,122
60	4	PO	6	43	0	1374	$8,244	$0	$8,244
60	4	PT	10	67	23	1374	$10,229	$3,511	$13,740
60	5	PO	2	14	0	1374	$2,748	$0	$2,748
60	6	PO	2	18	0	1374	$2,748	$0	$2,748
60	6	SO	2	0	7	1374	$0	$2,748	$2,748
60	N/A	SO	1	0	3	1472	$0	$1,472	$1,472
60	Unknown	PO	1	8	0	1472	$1,472	$0	$1,472
65	1	PO	4	38	0	2160	$8,640	$0	$8,640
65	1	PS	2	16	15	2160	$2,230	$2,090	$4,320
65	1	PT	2	16	5	2160	$3,291	$1,029	$4,320
65	2	PO	172	1515	0	1837	$315,964	$0	$315,964
65	2	PS	28	250	110	1837	$35,719	$15,717	$51,436
65	2	PT	121	1064	357	1837	$166,434	$55,843	$222,277
65	2	SO	4	0	13	1837	$0	$7,348	$7,348
65	3	PO	6	46	0	1613	$9,678	$0	$9,678
65	3	PS	1	3	3	1613	$807	$807	$1,613
65	3	PT	7	46	16	1613	$8,377	$2,914	$11,291
65	4	PT	3	22	11	1613	$3,226	$1,613	$4,839
65	4	SO	1	0	12	1613	$0	$1,613	$1,613

Height	Class	Pole Usage	Number of poles	Primary Connections	Secondary Connections	cost per pole	Pri Investment	Sec Investment	Total Investment
65	5	PT	1	4	0	1613	$1,613	$0	$1,613
70	1	PO	1	8	0	2459	$2,459	$0	$2,459
70	1	PT	1	8	0	2459	$2,459	$0	$2,459
70	2	PO	54	462	0	2278	$123,012	$0	$123,012
70	2	PS	8	96	37	2278	$13,154	$5,070	$18,224
70	2	PT	42	322	100	2278	$73,004	$22,672	$95,676
70	2	SO	1	0	4	2278	$0	$2,278	$2,278
70	3	PO	2	16	0	2278	$4,556	$0	$4,556
70	4	PT	1	2	2	2278	$1,139	$1,139	$2,278
70	6	PT	1	7	5	2278	$1,329	$949	$2,278
75	1	PO	1	10	0	2753	$2,753	$0	$2,753
75	2	PO	17	157	0	3156	$53,652	$0	$53,652
75	2	PS	4	33	16	3156	$8,502	$4,122	$12,624
75	2	PT	5	45	8	3156	$13,398	$2,382	$15,780
75	4	PT	1	8	3	3156	$2,295	$861	$3,156
80	1	PO	2	20	0	3188	$6,376	$0	$6,376
80	2	PO	9	76	0	3188	$28,692	$0	$28,692
80	2	PS	1	12	5	3188	$2,250	$938	$3,188
80	2	PT	1	12	6	3188	$2,125	$1,063	$3,188
80	Unknown	PO	1	6	0	3188	$3,188	$0	$3,188
85	2	PO	3	19	0	7087	$21,261	$0	$21,261
85	Unknown	PO	2	12	0	7087	$14,174	$0	$14,174
90	1	PO	1	8	0	8722	$8,722	$0	$8,722
90	Unknown	PO	1	6	0	8722	$8,722	$0	$8,722
100	Unknown	PO	1	6	0	9780	$9,780	$0	$9,780
105	Unknown	PO	1	6	0	9780	$9,780	$0	$9,780

Kentucky Power
Account 364 - Poles
Test Period Ending September 30, 2014

Summary	Number of poles	Primary Connections	Secondary Connections	Primary	Secondary	
Total	201,026	679,968	438,956	$85,286,856	$64,345,659	$149,632,515
				57.00%	43.00%	

	Number of poles	Primary Connections	Secondary Connections	Size to use	Cost	Primary	Secondary	
Customer-related	201,026	679,968	438,956	35'	**$615**	$75,130,318.96	$48,500,671	$123,630,990
						50.21%	32.41%	82.62%
Demand-related						$10,156,537	$15,844,988	$26,001,525
						6.79%	10.59%	17.38%

Note: Current installed cost of 35 foot pole (material and labor) is $615.

Kentucky Power
Account 365 - Overhead Conductors
Test Period Ending September 30, 2014

Conductor Size/Type	Pri. Est. Installed Cost per Foot	Sec. Est. Installed Cost per Foot	Pri Span Total (feet)	Pri Neutral Span Total (feet)	Sec Span Total (feet)	Sec Neutral Span Total (feet)	Pri Investment	Sec Investment	Total Investment
1/0AA	1.38	2.45	5,039,221	2,593,876	58,701	36,398	$10,533,674	$232,994	$10,766,668
1/0AL	1.38	2.45	264,644	293,363	6,514,521	3,066,587	$770,050	$23,473,715	$24,243,765
1/0AS	1.38	2.45	455,168	158,540	106,674	60,914	$846,917	$410,592	$1,257,510
1/0CC	2.79	4.95	198	198	139	139	$1,102	$1,381	$2,484
1/0CU	2.79	4.95	34,148	14,982	8,601	4,274	$137,074	$63,769	$200,843
1/0CW	2.79		31,996	1,985	-	-	$94,808	$0	$94,808
1/0Un	1.38	2.45	5,523	2,367	854	558	$10,888	$3,460	$14,348
159AA	1.88		-	877	-	-	$1,649	$0	$1,649
159AL	1.88		-	3,519	-	-	$6,617	$0	$6,617
159AS	1.88	3.34	-	98,990	-	539	$186,102	$1,799	$187,900
159Un	1.88		-	399	-	-	$751	$0	$751
1AA	1.38	2.45	244	284	94	47	$728	$346	$1,074
1AL		2.45	-	-	570	285	$0	$2,093	$2,093
1AS	1.38		-	115	-	-	$159	$0	$159
1CU	2.79	4.95	-	213	-	68	$593	$339	$932
2/0AA	1.88		179	304	-	-	$909	$0	$909
2/0AL	1.88	3.34	21	21	92,467	31,853	$78	$415,293	$415,372
2/0AS	1.88	3.34	12,038	4,895	2,908	1,454	$31,862	$14,569	$46,431
2/0CU	4.00	7.09	2,085	295	79	26	$9,511	$749	$10,260
2A5	0.82	1.52	1,439	1,239	536	346	$2,196	$1,341	$3,536
2AA	0.82	1.52	19,267,487	15,217,518	460,095	257,042	$28,277,704	$1,090,048	$29,367,752
2ACC	0.82	1.52	28,433	21,695	-	17	$41,106	$26	$41,132
2AL	0.82	1.52	438,405	351,622	5,342,887	2,484,578	$647,822	$11,897,747	$12,545,569
2AS	0.82	1.52	4,445,346	3,294,943	587,086	346,058	$6,347,037	$1,418,380	$7,765,417
2CC	2.36	4.37	2,371	2,371	764	413	$11,190	$5,150	$16,340
2CU	2.36	4.37	252,787	59,503	35,841	22,175	$737,006	$253,531	$990,537
2CW	2.36	4.37	42,513	1,753	653	156	$104,469	$3,539	$108,007
2Un	0.82	1.52	735	2,194	490	320	$2,401	$1,231	$3,632
3/0AA	2.38	4.23	4,464	18,428	174	87	$54,554	$1,106	$55,660
3/0AL	2.38	4.23	9,565	3,302	14,378	6,878	$30,666	$89,936	$120,602
3/0AS	2.38	4.23	267,579	18,013	4,724	2,576	$680,624	$30,885	$711,509
3/0CU	5.20	9.24	2,315	-	343	171	$12,043	$4,752	$16,794
336AA	2.04	5.93	31,060	11,112	418	304	$86,029	$4,285	$90,314
336AL	2.04	5.93	19,595	19,012	81,854	29,733	$78,757	$661,706	$740,463
336AS	2.12	6.63	75,760	3,066	237	179	$167,113	$2,759	$169,871
350AL		4.40	-	-	1,797	706	$0	$11,015	$11,015
397AS	2.12		307	-	-	-	$651	$0	$651
4/0A5	1.66		1,323	-	-	-	$2,196	$0	$2,196
4/0AA	1.66	3.21	7,160,936	1,473,248	3,159	4,352	$14,332,747	$24,111	$14,356,857
4/0AL	1.66	3.21	543,956	123,911	1,305,561	603,682	$1,108,660	$6,128,668	$7,237,327
4/0AS	1.66	3.21	307,130	102,267	2,200	1,100	$679,600	$10,595	$690,195
4/0AW	1.66		-	246	-	-	$408	$0	$408
4/0CU	4.52	8.74	73,217	76,332	3,271	2,188	$675,963	$47,712	$723,676
4/0Un	1.66	3.21	-	293	610	305	$487	$2,936	$3,423
4A5	0.78		742	742	-	-	$1,158	$0	$1,158
4AA	0.78	1.15	25,299	17,578	12,708	7,729	$33,444	$23,503	$56,947
4AAA	0.78		-	1,312	-	-	$1,023	$0	$1,023
4AAS	0.78		260	260	-	-	$406	$0	$406
4ACC	1.26	3.62	244,736	151,858	3,362	1,990	$499,708	$19,374	$519,082
4ACU	1.26		-	708	-	-	$892	$0	$892
4AL	0.78	1.15	17,293	14,444	2,150,359	1,653,808	$24,755	$4,374,792	$4,399,547
4AS	0.78	1.15	973,852	886,849	70,229	40,974	$1,451,347	$127,883	$1,579,230
4CC	1.26	3.62	227	3,325	294	454	$4,476	$2,705	$7,180
4CO	1.26		236	-	-	-	$298	$0	$298
4CU	1.26	3.62	5,021,795	3,204,502	1,114,140	621,072	$10,365,134	$6,281,466	$16,646,600
4CW	1.26	3.62	14,083	14,331	4,826	2,584	$35,802	$26,822	$62,623
4Un	0.78	1.15	269	156	-	157	$331	$180	$511
500AL		6.15	-	-	2,916	740	$0	$22,485	$22,485
500CU		35.96	-	-	278	86	$0	$13,060	$13,060
556AL	2.52	4.87	5,657,769	14,244	9,563	2,658	$14,293,473	$59,550	$14,353,022
6AA	0.78		7,507	6,164	-	-	$10,664	$0	$10,664
6AAL		1.15	-	-	644	644	$0	$1,481	$1,481

Conductor Size/Type	Pri. Est. Installed Cost per Foot	Sec. Est. Installed Cost per Foot	Pri Span Total (feet)	Pri Neutral Span Total (feet)	Sec Span Total (feet)	Sec Neutral Span Total (feet)	Pri Investment	Sec Investment	Total Investment
6ACC	1.26	3.62	2,179,307	1,863,959	99,859	65,288	$5,094,516	$597,832	$5,692,348
6ACU	1.26		1,637	1,122	-	-	$3,476	$0	$3,476
6AL	0.78	1.15	3,929	4,152	2,168	1,313	$6,304	$4,004	$10,308
6AS	0.78	1.15	6,101	3,259	791	791	$7,300	$1,820	$9,120
6CC	1.26	3.62	886,177	677,418	138,726	75,394	$1,970,130	$775,116	$2,745,246
6CU	1.26	3.62	224,462	117,418	145,612	84,235	$430,768	$832,049	$1,262,817
6CW	1.26	3.62	1,342	1,291	29,858	20,770	$3,318	$183,271	$186,588
6Un	0.78		523	523	-	-	$816	$0	$816
750AL	10.52	9.87	373	-	3,147	820	$3,925	$39,154	$43,079
795AL	3.06		83	-	-	-	$255	$0	$255
8AA	0.78		1,008	1,008	-	-	$1,573	$0	$1,573
8ACC	1.26	3.62	115,190	86,322	1,061	747	$253,905	$6,546	$260,451
8CC	1.26	3.62	87,595	67,134	1,492	1,374	$194,959	$10,374	$205,334
8CU	1.26	3.62	-	580	549	172	$731	$2,610	$3,341
UnknownAA	0.82		726	13,289	-	-	$11,493	$0	$11,493
UnknownAL	0.82	1.52	656	2,371	7,868	4,232	$2,482	$18,392	$20,873
UnknownAS	0.82		-	1,516	-	-	$1,243	$0	$1,243
UnknownAW	0.82		-	93	-	-	$76	$0	$76
UnknownCC	2.36		7,222	5,491	-	-	$30,005	$0	$30,005
UnknownCU	2.36		898	495	-	-	$3,287	$0	$3,287
UnknownUn	0.82	1.52	24,020	46,348	91,697	74,450	$57,702	$252,543	$310,245
Total			54,327,507	31,187,557	18,524,834	9,628,991	101,516,072	59,989,569	161,505,641

Summary	Primary	Secondary	Total
Total	$101,516,072	$59,989,569	$161,505,641
	62.86%	37.14%	100.00%

			Pri Span Total (feet)	Pri Neutral Span Total (feet)	Sec Span Total (feet)	Sec Neutral Span Total (feet)	Primary	Secondary	Total
			54,327,507	**31,187,557**	**18,524,834**	**9,628,991**			
Customer-related	Primary cost:		**$0.82**	Secondary cost:	**$1.52**		$70,122,353	$42,793,814	$112,916,166
							43.42%	26.50%	69.91%
Demand-related							$31,393,719	$17,195,756	$48,589,475
							19.44%	10.65%	30.09%

Note: $0.82 is the average installed cost (material & labor) of a foot of overhead primary conductor (#2 Aluminum Alloy - 2AA).
Note: $1.52 is the average installed cost (material & labor) of a foot of overhead secondary conductor (1 Oht - 1/OAA).

Kentucky Power
Account 367 - Underground Conductors
Test Period Ending September 30, 2014

Conductor Size/Type	Pri. Est. Installed Cost per Foot	Sec. Est. Installed Cost per Foot	Pri Span Total (Feet)	Pri Neutral Span Total (Feet)	Sec Span Total (Feet)	Sec Neutral Span Total (Feet)	Pri Investment	Sec Investment	Total Investment
1/0AL	4.485	2.26	814816.4	35908.75	54975.1	25895.91	$3,815,502	$182,768	$3,998,271
1/0CU	26.91	13.56	8043.41	769.86	0	48.75	$237,165	$661	$237,826
2/0AL		3.33	0	0	2544.86	964.45	$0	$11,686	$11,686
2/0CU	26.91		2660.91	0	0	0	$71,605	$0	$71,605
2AL	3.24	2.26	36053	2876.44	2643.95	1478.08	$126,131	$9,316	$135,447
2CU	19.44		5183.27	58.07	0	0	$101,892	$0	$101,892
350AL	2.52	4.4	356.3	5351.66	192633.49	85268.29	$14,384	$1,222,768	$1,237,152
350CU	24.93	24.93	0	295.9	620.6	7438.83	$7,377	$200,922	$208,298
4/0AL	6.38	2.99	33981.08	7500.17	49562.78	23408.79	$264,650	$218,185	$482,835
4/0CU	23.85	23.85	0	860.23	543.98	271.99	$20,516	$19,457	$39,973
4AL		1.16	0	0	19949.71	16763.54	$0	$42,587	$42,587
4CU		4.28	0	0	281.12	140.56	$0	$1,805	$1,805
500AL	6.03	6.15	1428.87	90.8	10437.46	4372.14	$9,164	$91,079	$100,243
500CU	35.96	35.96	751.38	0	15452.06	0	$27,020	$555,656	$582,676
6AAL	0.78	1.08	0	0	406.23	406.23	$0	$877	$877
6AL	0.78	1.08	636.15	84.54	85068.58	71532.02	$562	$169,129	$169,691
6CC		3.57	0	0	116.73	116.73	$0	$833	$833
6CU	1.26	3.57	443.92	206.47	8286.95	6406.77	$819	$52,457	$53,276
750AL	10.52	9.87	46596.14	224.14	145.65	48.55	$492,549	$1,917	$494,466
750CU	54.23	54.23	887.7	0	729.24	40.7	$48,140	$41,754	$89,894
8CU		3.57	0	0	4620.98	2310.49	$0	$24,745	$24,745
UnknownA	4.485	4.4	1175.97	0	308.85	284.44	$5,274	$2,610	$7,885
UnknownU	4.485	4.4	4199.97	1041.03	5338.69	3728.99	$23,506	$39,898	$63,404
Total	5.20	4.10	957,214	55,268	454,667	250,926	5,266,258	2,891,110	8,157,368

Summary	**Primary**	**Secondary**	**Total**
Total	$5,266,258	$2,891,110	$8,157,368
	64.56%	35.44%	100.00%

	Pri Span Total (Feet)	Pri Neutral Span Total (Feet)	Sec Span Total (Feet)	Sec Neutral Span Total (Feet)	**Primary**	**Secondary**	**Total**
	957,214	**55,268**	**454,667**	**250,926**			
Customer-related	Primary cost	**$3.24**	Secondary cost	**$2.26**	$3,280,443	$1,594,641	$4,875,084
					40.21%	19.55%	59.76%
Demand-related					$1,985,814	$1,296,470	$3,282,284
					24.34%	15.89%	40.24%

Note: $3.24 is the current installed cost (material & labor) of a foot of underground primary conductor (#2 Aluminum - 2AL).
Note: $2.26 is the current installed cost (material & labor) of a foot of underground secondary conductor (1 Oht - 1/OAL).

Kentucky
Account 368 - Transformers
Test Period Ending September 30, 2014

company	major_location	utility_account	state	retirement_unit	activity cost @ 9/2014	secondary voltage allocation	primary voltage allocation
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Cutout or Fuse Mounting - Inactive	$ 828.71		$829
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Protector	$ 2,368.10		$2,368
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Transformer	$ 87,776.74	$87,777	
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Switch, Time All Types	$ 94,358.76		$94,359
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Switch, Oil 1 Ph Remote Control	$ 114,379.60		$114,380
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Arrester	$ 117,080.93		$117,081
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Capacitor Switch	$ 236,243.36		$236,243
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Controller, Capacitor	$ 393,682.33		$393,682
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Non-unitized	$ 906,864.12		$906,864
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Regulator Controller	$ 1,217,406.87		$1,217,407
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Capacitor, Unit or Bank	$ 1,583,501.73		$1,583,502
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Regulator	$ 5,655,520.59		$5,655,521
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Cutout or Fuse Mounting	$ 14,099,822.48		$14,099,822
Kentucky Power - Distr	Distribution Mass Prop - KY, KEP	36800 - Line Transformers	KY	Transformer, Line	$ 97,811,788.95	$97,811,789	
			VA	**Total**	**$122,321,623.27**	**$97,899,565.69**	**$24,422,057.58**

Summary	**Secondary**	**Primary**
Total	**80.03%**	**19.97%**

	# of Transformers	$/Transformer				Secondary	Primary
OH Distribution Transformers	89,197	**$1,116**	$ 99,543,852.00				
UG Distribution Transformers	1,459	**$1,584**	$ 2,311,056.00				
Total Customer Related	90,656		$ 101,854,908.00		Total Customer Related	$ 81,519,121	$ 20,335,787
Remaining Demand Related Portion			$20,466,715.27		Remaining Demand Related Portion	$16,380,444.29	$4,086,270.98
Customer-related						**66.64%**	**16.62%**
Demand-related						**13.39%**	**3.34%**

Note: Current installed cost (material & labor) of 25 kVA single phase overhead transformer is $1,116.
Note: Current installed cost (material & labor) of 25 kVA single phase underground transformer is $1,584.

Marginal Customer Connection Study
Kentucky Power 2014

Kentucky Power MCAC (Customer Hookup Cost): 7.2kV				
Account	Description	Total Installed Cost	% of Total Cost	Avg Serv Life (yrs)
3640000	Poles, Towers & Fixtures	$1,464.10	36.63%	31
3650000	OH Conductor & Devices	$935.71	23.41%	40
3680000	Transformer Devices	$1,221.01	30.55%	32
3690000	Services	$271.47	6.79%	33
5860000	Meter Expense	$105.06	2.63%	25
Total Work Request Charges		$3,997.35		

Marginal Cost Per Month to Connect a Residential Customer	
Weighted Avg Accounting Life	33
Levelized 33 Year Carrying Charge	12.43%
Total Capital Cost	$3,997.35
Monthly Capital Recovery $	$41.41
Total Basic Service Charge $/month	**$41.41**

Big Sandy 1 Operations Rider (BS1OR)

Big Sandy 1 Coal Operations

Revenue Requirement

	KY Retail	
Non Fuel Plant O&M - Demand	$ 9,150,077	a
Non Fuel Plant O&M - Energy	$ 3,351,767	b
Jan- Sept 14 PJM Charges and Credits	$ 4,239,908	c
Annualize PJM Charges and Credits	$ 5,653,211	d = c/9*12
Total BS1 Operational Expense	$ 18,155,055	e = a+b+d
gross up factor	1.004977	f
KY Retail Total	$ 18,245,413	g = e*f
Demand Total	$ 9,195,617	h = a*f
Energy Total	$ 9,049,796	i= (b+d)*f
Total	$ 18,245,413	

Kentucky Power Company
Big Sandy 1 Operation Rider Rate Design

	Demand	Energy	Total
KY Retail Jurisdiction Revenue Requirement	$9,195,617	$9,049,796	$18,245,413

Class (1)	Historic Period Billing Energy (2)	Historic Period Billing Demand (3)	Test Year CP / kWh Ratio (4)	CP Demand Allocation Factor (5) = (2) x (4)	Allocated Demand Related Costs (6) on (5)	Allocated Energy Related Costs (7) on (2)	$ / kW Rate (8) = (6) / (3)	$ / kWh Rate (9) = (7) / (2)	Revenue Verification (10)	Difference (11) = (10) - (6) - (7)
RES	2,260,149,747		0.0236060%	533,531	$4,315,835	$3,150,585	$ -	$0.00330	$7,458,494	-$7,926
SGS	142,560,729		0.0163937%	23,371	189,053	198,726	$ -	$0.00272	387,765	-$14
MGS	507,158,704	2,119,598	0.0177002%	89,768	726,151	706,965	$ 0.34	$0.00141 [2]	1,435,757	$2,641
Non Demand MGS Sec [1]	6,484,718		0.0177002%	1,148	9,286	9,040	$ -	$0.00283	18,352	$26
LGS	705,405,060	2,169,269	0.0169381%	119,482	966,513	983,315	$ 0.45	$0.00139	1,956,684	$6,856
LGS LMTOD	1,959,939		0.0169381%	332	2,686	2,732	$ -	$0.00276	5,409	-$9
IGS (QP / CIP-TOD)	2,818,677,591	5,429,712	0.0130626%	368,192	2,978,376	3,929,159	$ 0.55	$0.00139	6,904,303	-$3,232
MW	3,864,039		0.0134057%	518	4,190	5,386	$ -	$0.00248	9,583	$7
OL	37,640,598		0.0009431%	355	2,872	52,470	$ -	$0.00147	55,332	-$10
SL	8,190,082		0.0009890%	81	655	11,417	$ -	$0.00147	12,039	-$33
Total	6,492,091,207	9,718,579		1,136,778	$9,195,617	$9,049,795			$18,243,719	($1,693)

Notes:
[1] Non Demand MGS Sec includes MGS RL, MGS LMTOD and MGS TOD
[2] Revised after Revenue Verification

KPCo KY Retail PSC Jurisdiction
Class Billing Determinants
12 Months Ended Sept 2014

Class (1)	kWh Energy	kW 12 CP
RES	2,260,149,747	533,531
SGS	142,560,729	23,371
MGS	507,158,704	89,768
Non Demand MGS Sec	6,484,718	
LGS	705,405,060	119,482
LGS LMTOD	1,959,939	
QP/CIP	2,818,677,591	368,192
MW	3,864,039	518
OL	37,640,598	355
SL	8,190,082	81
Total	6,492,091,207	1,135,298

Kentucky Power Company

Adjustment to PJM Charges and Credits to Reflect the AEP East Pool Termination, Removal of Big Sandy 1 & 2 PJM Charges and Annualization of Stand Alone PJM Charges
Test Year Twelve Months Ended 9/30/2014

LINE NO.	DESCRIPTION	KPCO TOTAL COMPANY ADJUSTMENT	ALLOCATION FACTOR	KENTUCKY PSC RETAIL JURISDICTION ADJUSTMENT	
	Operating Expenses				
1	Energy Related	$ 1,593,344	Energy	$ 1,571,037	
2	Demand Related	$ 6,007,677	PDAF/Specific	$ 6,013,265	
3	Total	$ 7,601,021		$ 7,584,302	**Increase Operating Expense**

Exhibit AEV 5 - PJM Adjustment Calculations
KPCo 12 Months Ended September 30, 2014
Positive amounts are charges (expense) negative amounts are credits (revenue)

												Total KPCo	KY Retail				Kentucky PSC
				Test Year Per Books	Remove Pool (Q4 2013)	Remove Big Sandy1	Remove Big Sandy2	Reclass MWh from OSS to Serve LSE	Add Incremental LSE Congestion Costs	January - September 2014 Sub Total	Anualization Adj	Going Level LSE PJM Charges and Credits	Going Level LSE PJM Charges and Credits	Total of Adjustments	Kentucky PSC Jurisdiction Allocation Factor		Jurisdiction Total Adjustment
Line	**Acct**	**Description**	**Classification**	**A**	**B**	**C**	**D**	**E**	**F**	**G = sum A-F**	**H = i-G**	**i = G/(9/12)**	**J = i*L**	**K = i-A**		**L**	**M = K*L**
1-PJM	4470093	PJM Implicit Congestion-LSE	Energy	$ 20,004,934	$ (1,250,735)	$ (4,562,334)	$ (14,017,902)	$ 11,822,355	$ 2,783,354	$ 14,779,673	$ 4,926,558	$ 19,706,230	$ 19,430,343	$ (298,704)	Energy	0.986	$ (294,522)
2-PJM	4470101	PJM FTR Revenue-LSE	Energy	$ (9,650,962)	$ 826,791					$ (8,824,172)	$ (2,941,391)	$ (11,765,562)	$ (11,600,845)	$ (2,114,600)	Energy	0.986	$ (2,084,996)
3-PJM	4470116	PJM Meter Corrections-LSE	Energy	$ (53,563)	$ 29,886					$ (23,677)	$ (7,892)	$ (31,569)	$ (31,127)	$ 21,994	Energy	0.986	$ 21,686
4-PJM	4470202	PJM OpRes-LSE-Credit	Energy	$ (1,937,677)	$ 1,280,467	$ 115,255	$ 137,461			$ (404,494)	$ (134,831)	$ (539,325)	$ (531,774)	$ 1,398,352	Energy	0.986	$ 1,378,776
5-PJM	4470203	PJM OpRes-LSE-Charge	Energy	$ 5,537,329	$ (748,077)					$ 4,789,252	$ 1,596,417	$ 6,385,669	$ 6,296,270	$ 848,340	Energy	0.986	$ 836,463
6-PJM	5550040	PJM Inadvertent Mtr Res-LSE	Energy	$ (42,077)	$ 16,223					$ (25,854)	$ (8,618)	$ (34,472)	$ (33,990)	$ 7,605	Energy	0.986	$ 7,499
7-PJM	5550041	PJM Ancillary Serv.-Sync	Energy	$ 5,611	$ 50					$ 5,661	$ 1,887	$ 7,548	$ 7,442	$ 1,937	Energy	0.986	$ 1,910
8-PJM	5550074	PJM Reactive-Charge	Demand	$ (10,125)	$ (1,702)					$ (11,826)	$ (3,942)	$ (15,769)	$ (15,548)	$ (5,644)	PDAF	0.986	$ (5,565)
9-PJM	5550075	PJM Reactive-Credit	Demand	$ 28,427	$ (28,426)					$ 1	$ 0	$ 1	$ 1	$ (28,425)	PDAF	0.986	$ (28,027)
10-PJM	5550076	PJM Black Start-Charge	Demand	$ 2,003,256	$ (776,903)					$ 1,226,353	$ 408,784	$ 1,635,138	$ 1,612,246	$ (368,118)	PDAF	0.986	$ (362,965)
11-PJM	5550077	PJM Black Start-Credit	Demand	$ (3,073)	$ 3,073					$ (0)	$ (0)	$ (0)	$ (0)	$ 3,073	PDAF	0.986	$ 3,030
12-PJM	5550078	PJM Regulation-Charge	Energy	$ 1,914,421	$ (225,120)					$ 1,689,301	$ 563,100	$ 2,252,401	$ 2,220,868	$ 337,980	Energy	0.986	$ 333,248
13-PJM	5550079	PJM Regulation-Credit	Energy	$ (434,775)	$ 21,186	$ 121,628	$ 481,229			$ 189,267	$ 63,089	$ 252,357	$ 248,824	$ 687,132	Energy	0.986	$ 677,512
14-PJM	5550083	PJM Spinning Reserve-Charge	Energy	$ 1,381,828	$ (33,999)					$ 1,347,829	$ 449,276	$ 1,797,106	$ 1,771,946	$ 415,278	Energy	0.986	$ 409,464
15-PJM	5550084	PJM Spinning Reserve-Credit	Energy	$ (340,677)	$ 17,297	$ 44,365	$ 85,007			$ (194,008)	$ (64,669)	$ (258,678)	$ (255,056)	$ 81,999	Energy	0.986	$ 80,851
16-PJM	5550090	PJM 30m Suppl Rserv Charge LSE	Energy	$ 382,926	$ 3,731					$ 386,657	$ 128,886	$ 515,543	$ 508,325	$ 132,617	Energy	0.986	$ 130,760
17-PJM	5550093	Peak Hour Avail charge - LSE***	Demand	$ (67,133)	$ -					$ (67,133)	$ -	$ (67,133)	$ (66,193)	$ -	PDAF	0.986	$ -
18-PJM	5614001	PJM Admin-SSC&DS-Internal	Energy	$ 626,172	$ (134,296)	$ (19,025)	$ (58,624)	$ 77,649		$ 491,877	$ 163,959	$ 655,835	$ 646,654	$ 29,663	Energy	0.986	$ 29,248
19-PJM	5618001	PJM Admin-RP&SDS- Internal	Energy	$ 149,196	$ (32,322)					$ 116,874	$ 38,958	$ 155,832	$ 153,651	$ 6,636	Energy	0.986	$ 6,543
20-PJM	5757001	PJM Admin-MAM&SC- Internal	Energy	$ 688,223	$ (144,220)					$ 544,003	$ 181,334	$ 725,337	$ 715,182	$ 37,114	Energy	0.986	$ 36,594
21-PJM Subtotal				$ 20,182,261	$ (1,177,095)	$ (4,300,110)	$ (13,372,829)	$ 11,900,004	$ 2,783,354	$ 16,015,584	$ 5,360,906	$ 21,376,490	$ 21,077,219	$ 1,194,229			$ 1,177,510

												Total KPCo	KY Retail		Kentucky PSC	Kentucky PSC
				Test Year Per Books						Test Year Per Books	Anualization Adj	Going Level LSE PJM Charges and Credits	Going Level LSE PJM Charges and Credits	Total of Adjustments	Jurisdiction Allocation Factor	Jurisdiction Total Adjustment
Line	**Acct**	**Description**	**Classification**	**A**						**B=A**	**C**	**D**	**E=D**	**F=E-A**		**G=F**
22-OATT	4561035	Network Integrated Transmission Service	Demand	$ 37,238,858						$ 37,238,858	$ 4,353,853	$ 41,592,711	$ 41,592,711	$ 4,353,853	Direct to KY Retail	$ 4,353,853
23-OATT	5650016	Network Integrated Transmission Service	Demand	$ 5,140,478						$ 5,140,478	$ 601,009	$ 5,741,487	$ 5,741,487	$ 601,009	Direct to KY Retail	$ 601,009
24-OATT	4561005	Firm and Non-Firm Point to Point Transmision Revenues	Demand	$ (680,082)						$ (680,082)		$ (680,082)	$ (680,082)	$ -	Direct to KY Retail	$ -
25-OATT	4561036	Schedule 1a Charges	Energy	$ 614,746						$ 614,746		$ 614,746	$ 614,746	$ -	Direct to KY Retail	$ -
26-OATT	5650015	Schedule 1a Charges	Energy	$ 41,137						$ 41,137		$ 41,137	$ 41,137	$ -	Direct to KY Retail	$ -
27-OATT	4561060	Transmission Enhancement Charges	Demand	$ 459,418						$ 459,418	$ 147,476	$ 606,894	$ 606,894	$ 147,476	Direct to KY Retail	$ 147,476
28-OATT	5650012	Transmission Enhancement Charges	Demand	$ 3,976,612						$ 3,976,612	$ 1,276,511	$ 5,253,123	$ 5,253,123	$ 1,276,511	Direct to KY Retail	$ 1,276,511
29-OATT	5650019	Transmission Enhancement Charges - Affil	Demand	$ 355,174						$ 355,174	$ 114,013	$ 469,187	$ 469,187	$ 114,013	Direct to KY Retail	$ 114,013
30-OATT	4561002	RTO Formation Costs	Demand	$ 140,253						$ 140,253		$ 140,253	$ 140,253	$ -	Direct to KY Retail	$ -
31-OATT	4561003	Expansion Cost Recovery Charge	Demand	$ 86,070						$ 86,070	$ (86,070)	$ -	$ -	$ (86,070)	Direct to KY Retail	$ (86,070)
32-OATT Subtotal				$ 47,372,664	$ -	$ -	$ -	$ -	$ -	$ 47,372,664	$ 6,406,792	$ 53,779,456	$ 53,779,456	$ 6,406,792		$ 6,406,792
Total of Test Year PJM Tracker Accounts				**$ 67,554,925**	**$ (1,177,095)**	**$ (4,300,110)**	**$ (13,372,829)**	**$ 11,900,004**	**$ 2,783,354**	**$ 63,388,248**	**$ 11,767,698**	**$ 75,155,946**	**$ 74,856,675**	**$ 7,601,021**		**7,584,302**

***Peak hour availability charges are calculated once each year by PJM, no annualization adj neede

PTCPT_CD LSEKPD
STTL_PUB_CD FINAL

Sum of SETTLE_AMT	Column Labels									
Row Labels	1/1/2014	2/1/2014	3/1/2014	4/1/2014	5/1/2014	6/1/2014	7/1/2014	8/1/2014	9/1/2014	Grand Total
BAKER 26 KV BS2_GEN	11,534,827	782,111	231,558	114,130	162,409	226,128	598,256	129,712	238,771	14,017,902
1210 - Day-Ahead Transm	12,531,920	966,501	263,477	116,865	125,643	248,196	592,789	122,729	248,964	15,217,084
1215 - Balancing Transmis	-997,094	-184,390	-31,919	-2,736	36,767	-22,068	5,467	6,983	-10,193	-1,199,183
BIGSANDY22 KV BS1_GEN	2,958,922	415,035	830,687	29,465	14,200	65,590	167,216	37,983	43,236	4,562,334
1210 - Day-Ahead Transm	3,379,045	471,154	923,093	31,800	10,924	74,812	173,308	32,421	45,322	5,141,879
1215 - Balancing Transmis	-420,123	-56,119	-92,406	-2,335	3,276	-9,221	-6,092	5,562	-2,086	-579,544
Grand Total	14,493,748	1,197,146	1,062,245	143,595	176,610	291,719	765,472	167,696	282,007	18,580,238

PTCPT_CD LSEKPD
STTL_PUB_CD FINAL

Sum of STTL_ITEM_QNTY	Column Labels									
Row Labels	1/1/2014	2/1/2014	3/1/2014	4/1/2014	5/1/2014	6/1/2014	7/1/2014	8/1/2014	9/1/2014	Grand Total
BAKER 26 KV BS2_GEN	(283,901)	(226,244)	(52,310)	(157,978)	(145,001)	(191,815)	(183,490)	(215,730)	(82,548)	(1,539,017)
1210 - Day-Ahead Transm	(299,373)	(251,899)	(55,908)	(165,186)	(156,843)	(196,816)	(207,287)	(238,925)	(82,477)	(1,654,714)
1215 - Balancing Transmis	15,472	25,655	3,598	7,208	11,842	5,001	23,797	23,195	(71)	115,697
BIGSANDY22 KV BS1_GEN	(82,836)	(75,943)	(99,841)	(35,521)	(49,944)	(59,530)	(36,197)	(58,146)	(9,035)	(506,993)
1210 - Day-Ahead Transm	(95,975)	(83,670)	(107,792)	(42,612)	(54,670)	(64,631)	(41,039)	(65,873)	(9,661)	(565,923)
1215 - Balancing Transmis	13,138	7,727	7,951	7,090	4,725	5,102	4,842	7,727	627	58,929
Grand Total	(366,737)	(302,186)	(152,151)	(193,499)	(194,945)	(251,345)	(219,687)	(273,876)	(91,582)	(2,046,008)

PTCPT_CD OSSKPD
STTL_PUB_CD FINAL

Sum of SETTLE_AMT	Column Labels								
Row Labels	1/1/2014	2/1/2014	3/1/2014	4/1/2014	5/1/2014	6/1/2014	7/1/2014	8/1/2014	Grand Total
KAMMER2 26 KV ML1_R	921,640	152,553	888,095	110,240	38,016	103,019	237,174	70,210	2,520,947
1210 - Day-Ahead Transm	835,649	130,396	833,817	110,212	38,581	87,795	246,027	72,043	2,354,519
1215 - Balancing Transmis	85,991	22,157	54,279	28	-566	15,224	-8,853	-1,833	166,428
KAMMER2 26 KV ML2_R	2,632,896	426,901	534,387	87,510	69,447	80,398	322,001	57,615	4,211,154
1210 - Day-Ahead Transm	2,555,967	430,001	541,926	88,395	69,360	79,181	333,186	61,496	4,159,512
1215 - Balancing Transmis	76,929	-3,100	-7,540	-885	87	1,217	-11,185	-3,881	51,642
ROCKPOR226 KV RP1_GEI	2,041,428	348,373	704,391	110,833		296,466	278,161	125,331	3,904,983
1210 - Day-Ahead Transm	1,935,231	355,876	709,152	108,901		374,204	294,224	126,585	3,904,174
1215 - Balancing Transmis	106,197	-7,503	-4,761	1,932		-77,738	-16,063	-1,255	810
ROCKPOR226 KV RP2_GEI	1,918,542	241,449	582,193	80,390	66,107	327,079	309,372	95,919	3,621,051
1210 - Day-Ahead Transm	1,843,883	248,951	586,206	76,264	65,430	376,139	311,716	97,916	3,606,506
1215 - Balancing Transmis	74,659	-7,502	-4,013	4,126	676	-49,061	-2,344	-1,997	14,545
Grand Total	7,514,506	1,169,276	2,709,066	388,972	173,569	806,961	1,146,709	349,075	14,258,134

PTCPT_CD OSSKPD
STTL_PUB_CD FINAL

Sum of STTL_ITEM_QNTY	Column Labels								
Row Labels	1/1/2014	2/1/2014	3/1/2014	4/1/2014	5/1/2014	6/1/2014	7/1/2014	8/1/2014	Grand Total
KAMMER2 26 KV ML1_R	-15,328	-9,259	-79,491	-103,340	-49,918	-66,549	-96,630	-110,037	-530,551
1210 - Day-Ahead Transm	-13,125	-8,312	-77,149	-104,498	-51,269	-63,481	-99,549	-112,988	-530,371
1215 - Balancing Transmis	-2,203	-947	-2,341	1,158	1,351	-3,068	2,919	2,952	-179
KAMMER2 26 KV ML2_R	-46,399	-83,996	-74,137	-67,373	-48,423	-93,712	-106,323	-77,063	-597,424
1210 - Day-Ahead Transm	-46,528	-85,137	-73,650	-63,970	-45,388	-95,312	-110,948	-73,410	-594,342
1215 - Balancing Transmis	129	1,141	-487	-3,403	-3,035	1,601	4,624	-3,653	-3,082
ROCKPOR226 KV RP1_GEI	-49,563	-34,060	-53,897	-64,711		-58,176	-44,755	-73,057	-378,219
1210 - Day-Ahead Transm	-45,808	-33,767	-53,890	-65,043		-60,398	-45,711	-73,122	-377,740
1215 - Balancing Transmis	-3,755	-293	-8	332		2,222	956	65	-479
ROCKPOR226 KV RP2_GEI	-41,425	-23,578	-45,385	-50,853	-57,803	-60,632	-58,364	-54,499	-392,539
1210 - Day-Ahead Transm	-39,744	-23,604	-45,393	-49,327	-58,951	-63,299	-58,941	-52,759	-392,018
1215 - Balancing Transmis	-1,680	26	7	-1,526	1,148	2,667	577	-1,740	-520
Grand Total	-152,714	-150,892	-252,910	-286,277	-156,144	-279,068	-306,073	-314,656	-1,898,733

SUBACCOUNT AEPKPD
OP_MONTH (Multiple Items)

Row Labels	Sum of DA_OP_RES	Sum of BAL_LOST_OP_CR	Sum of REG_RMCCP	Sum of REG_RMPCP	Sum of REG_LOST_OPPORTUNITY_COST	Sum of SYNCH_RESERVE_TIER1	Sum of SYNCH_SRMCP	Sum of SYNCH_RES_LOST_OPPORTUNITY
AEP BIG SANDY 1		152,658	65,341	4,886	51,401	24,094	16,523	3,748
AEP BIG SANDY 2		182,070	145,524	11,019	324,686	54,932	18,904	11,171
Grand Total		334,728	210,865	15,905	376,087	79,026	35,427	14,919
		LRS	Net	Net	Net	Net	Net	Net

SUBACCOUNT AEPKPD
Regulation LOC credits from test year
Sum of BAL_LOST_ Column Labels

Row Labels	AEP BIG SA	AEP BIG SANDY 2	Grand Total	KPD	OSS Ratio	LSE Ratio	BS 1 LSE LOC Credit	BS 2 LSE LOC Credit
Jan-14	152,658	182,070	334,728	1/1/2014	0.24501	0.75499	115,255.26	137,461.03
Feb-14		-	-	2/1/2014	0.23695	0.76305		
Mar-14		-	-	3/1/2014	0.24064	0.75936		
Apr-14		-	-	4/1/2014	0.32194	0.67806		
May-14		-	-	5/1/2014	0.1836	0.8164		
Jun-14		-	-	6/1/2014	0.36622	0.63378		
Jul-14		-	-	7/1/2014	0.32581	0.67419		
Aug-14		-	-	8/1/2014	0.37329	0.62671		
Sep-14		-	-					
Grand Total	152,658	182,070	334,728					

Kentucky Power Company
PJM Rider Rate Design

	Demand	Energy	Total
KY Retail Jurisdiction Revenue Requirement	$0	$0	$0

Class (1)	Historic Period Billing Energy (2)	Historic Period Billing Demand (3)	Test Year CP / kWh Ratio (4)	CP Demand Allocation Factor (5) = (2) x (4)	Allocated Demand Related Costs (6) on (5)	Allocated Energy Related Costs (7) on (2)	$ / kW Rate (8) = (6) / (3)	$ / kWh Rate (9) = (7) / (2)	Revenue Verification (10)	Difference (11) = (10) - (6) - (7)
RES	2,260,149,747		0.0236060%	533,531	$0	$0	$ -	$0.00000	$0	$0
SGS	142,560,729		0.0163937%	23,371	0	0	$ -	$0.00000	0	$0
MGS	507,158,704	2,119,598	0.0177002%	89,768	0	0	$ -	$0.00000	0	$0
Non Demand MGS Sec [1]	6,484,718		0.0177002%	1,148	0	0	$ -	$0.00000	0	$0
LGS	705,405,060	2,169,269	0.0169381%	119,482	0	0	$ -	$0.00000	0	$0
LGS LMTOD	1,959,939		0.0169381%	332	0	0	$ -	$0.00000	0	$0
IGS (QP / CIP-TOD)	2,818,677,591	5,429,712	0.0130626%	368,192	0	0	$ -	$0.00000	0	$0
MW	3,864,039		0.0134057%	518	0	0	$ -	$0.00000	0	$0
OL	37,640,598		0.0009431%	355	0	0	$ -	$0.00000	0	$0
SL	8,190,082		0.0009890%	81	0	0	$ -	$0.00000	0	$0
Total	6,492,091,207	9,718,579		1,136,778	$0	$0			$0	$0

Notes:
[1]Non Demand MGS Sec includes MGS RL, MGS LMTOD and MGS TOD

KPCo KY Retail PSC Jurisdiction
Class Billing Determinants
12 Months Ended Sept 2014

Class (1)	kWh Energy	kW 12 CP
RES	2,260,149,747	533,531
SGS	142,560,729	23,371
MGS	507,158,704	89,768
Non Demand MGS Sec	6,484,718	
LGS	705,405,060	119,482
LGS LMTOD	1,959,939	
QP/CIP	2,818,677,591	368,192
MW	3,864,039	518
OL	37,640,598	355
SL	8,190,082	81
Total	6,492,091,207	1,135,298

Exhibit AEV 7 - OSS Adjustment Calculations
KPCo 12 Months Ended September 30, 2014
Positive amounts are charges (expense) negative amounts are credits (revenue)

Line	Acct	Description	Test Year Total	Remove Pool	Remove Big Sandy 2	LSE/OSS Reclass	Jan-Sept 2014 Non-Margin Accts	Annualization ADJ	Total KPCo Going Level OSS Total	Total KPCo OSS Adj	Kentucky Retail PSC Juris Allocation Method	Kentucky Retail PSC Juris Allocation Factor	Kentucky Retail PSC Juris Adjustment
			A	B	C	D	E = Sum A-D	F = G-E	G =E/(9/12)	H = G-A		i	J = G*i
1	4470089	PJM Energy Sales Margin	(112,332,338)	1,882,476	86,161,517				(24,288,344)	88,043,994	Energy	0.986	86,811,378
2	4470002	Sales for Resale - NonAssoc	(997,118)	993,987			(3,131)	(1,044)	(4,175)	992,943	Energy	0.986	979,042
3	4470006	Sales for Resale-Bookout Sales	(16,025,313)	3,267,142			(12,758,170)	(4,252,723)	(17,010,894)	(985,581)	Energy	0.986	(971,783)
4	4470010	Sales for Resale-Bookout Purch	14,698,090	(2,236,243)			12,461,847	4,153,949	16,615,796	1,917,706	Energy	0.986	1,890,858
5	4470028	Sale/Resale - NA - Fuel Rev	(1,137,563)	986,000			(151,564)	(50,521)	(202,085)	935,478	Energy	0.986	922,382
6	4470066	Power Trading Transmission Expense	124	(40)			84	28	112	(12)	Energy	0.986	(12)
7	4470081	Financial Spark Gas - Realized	(119,589)	81,641			(37,948)	(12,649)	(50,597)	68,991	Energy	0.986	68,025
8	4470082	Financial Electric Realized	(722,279)	(999,271)			(1,721,551)	(573,850)	(2,295,401)	(1,573,122)	Energy	0.986	(1,551,098)
9	4470098	PJM Oper.Reserve Rev-OSS	2,782,692	181,140	44,609		3,008,441	1,002,814	4,011,255	1,228,563	Energy	0.986	1,211,363
10	4470099	Capacity Cr. Net Sales	(549,664)	117,100			(432,564)	(144,188)	(576,752)	(27,088)	Demand	0.986	(26,708)
11	4470100	PJM FTR Revenue-OSS	(827,287)	19,983			(807,303)	(269,101)	(1,076,405)	(249,118)	Energy	0.986	(245,630)
12	4470106	PJM Pt2Pt Trans.Purch-NonAff.	358	(331)			27	9	37	(322)	Energy	0.986	(317)
13	4470107	PJM NITS Purch-NonAff.	(8,673)	(4,803)			(13,477)	(4,492)	(17,969)	(9,296)	Energy	0.986	(9,165)
14	4470109	PJM FTR Revenue-Spec	36,316	17,090			53,406	17,802	71,207	34,891	Energy	0.986	34,403
15	4470110	PJM TO Admin. Exp.-NonAff.	(34,378)	(953)			(35,331)	(11,777)	(47,108)	(12,730)	Energy	0.986	(12,552)
16	4470112	Non-Trading Bookout Sales-OSS	(4,943)	-			(4,943)	(1,648)	(6,591)	(1,648)	Energy	0.986	(1,625)
17	4470115	PJM Meter Corrections-OSS	(14,217)	31,708			17,491	5,830	23,322	37,539	Energy	0.986	37,013
18	4470124	PJM Incremental Spot-OSS	(1)	1			0	0	0	1	Energy	0.986	1
19	4470126	PJM Incremental Imp Cong-OSS	28,632,134	(670,134)	(8,583,469)	(11,822,355)	7,556,175	2,518,725	10,074,900	(18,557,233)	Energy	0.986	(18,297,432)
20	4470143	Financial Hedge Realized	(2,242,312)	44,899			(2,197,413)	(732,471)	(2,929,884)	(687,572)	Energy	0.986	(677,946)
21	4470144	Realiz.Sharing - 06 SIA	(318)	318			-	-	-	318	Energy	0.986	314
22	4470168	Interest Rate Swaps-Power	18,648	(5,089)			13,559	4,520	18,079	(569)	Energy	0.986	(561)
23	4470170	Non-ECR Auction Sales-OSS	(2,274,237)	888,839			(1,385,398)	(461,799)	(1,847,197)	427,040	Energy	0.986	421,061
24	4470174	PJM Whlse FTR Rev - OSS	(6,635)	6,635			(0)	(0)	(0)	6,635	Energy	0.986	6,542
25	4470206	PJM Trans loss credits-OSS	(1,868,448)	173,334			(1,695,115)	(565,038)	(2,260,153)	(391,705)	Energy	0.986	(386,221)
26	4470209	PJM transm loss charges-OSS	14,804,122	(920,700)	(5,665,550)	(4,151,338)	4,066,534	1,355,511	5,422,045	(9,382,077)	Energy	0.986	(9,250,728)
27	4470214	PJM 30m Suppl Reserve CR OSS	(28,587)	379			(28,208)	(9,403)	(37,610)	(9,023)	Energy	0.986	(8,897)
28	4470220	PJM Regulation - OSS	(184,599)	2,432			(182,167)	(60,722)	(242,889)	(58,290)	Energy	0.986	(57,474)
29	4470221	PJM Spinning Reserve - OSS	(42,868)	32,607			(10,260)	(3,420)	(13,681)	29,187	Energy	0.986	28,779
30	4470222	PJM Reactive - OSS	(568,359)	107,300			(461,059)	(153,686)	(614,746)	(46,387)	Energy	0.986	(45,737)
31	4470222	PJM Reactive - OSS	(568,359)	107,300			(461,059)	(153,686)	(614,746)	(46,387)	Energy	0.986	(45,737)
32	5550039	PJM Inadvertent Mtr Res-OSS	(66,033)	7,851			(58,182)	(19,394)	(77,576)	(11,543)	Energy	0.986	(11,382)
33	5550099	PJM Purchases-non-ECR-Auction	2,098,111	(646,802)			1,451,310	483,770	1,935,079	(163,032)	Energy	0.986	(160,749)
34	5550100	Capacity Purchases-Auction	118,556	(56,942)			61,614	20,538	82,152	(36,404)	Demand	0.986	(35,895)
35	5550107	Capacity purchases - Trading	248,187	(28,824)			219,363	73,121	292,484	44,297	Energy	0.986	43,676
36	5614000	PJM Admin-SSC&DS-OSS	472,517	(68,206)	(66,009)		338,302	112,767	451,070	(21,448)	Energy	0.986	(21,148)
37	5614008	PJM Admin Defaults OSS	2,417	-			2,417	806	3,223	806	Energy	0.986	794
38	5618000	PJM Admin-RP&SDS-OSS	113,053	(16,332)			96,721	32,240	128,961	15,908	Energy	0.986	15,685
39	5757000	PJM Admin-MAM&SC- OSS	510,751	(74,196)			436,556	145,519	582,074	71,323	Energy	0.986	70,325
		Non PJM Energy Margin Acct Totals	36,244,296	1,338,819	(14,270,419)	(15,973,693)	7,339,003	2,446,334	9,785,337	(26,458,959)			(26,088,533)
		PJM Energy SLES Margin Totals	(112,332,338)	1,882,476	86,161,517				(24,288,344)	88,043,994			86,811,378
		Total OSS Margin							(14,503,007)	61,585,035			60,722,844

(14,299,964.43) KPCo KY Retail Going Level OSS Margins

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For:	**)**	
(1) A General Adjustment Of Its Rates For Electric	**)**	
Service; (2) An Order Approving Its 2014	**)**	**Case No. 2014-00396**
Environmental Compliance Plan; (3) An Order	**)**	
Approving Its Tariffs And Riders; And (4) An	**)**	
Order Granting All Other Required Approvals	**)**	
And Relief	**)**	

DIRECT TESTIMONY OF

RANIE K. WOHNHAS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Ranie K. Wohnhas being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and 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. 2014-00396
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 15th day of December, 2014.

Judy K Rasquist 481393

Notary Public

My Commission Expires: January 23, 2017

DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Ranie K. Wohnhas. My position is Managing Director, Regulatory and Finance, Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40601.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science degree with a major in accounting from Franklin University, Columbus, Ohio in December 1981. I began work with Columbus Southern Power in 1978 working in various customer services and accounting positions. In 1983, I transferred to Kentucky Power Company working in accounting, rates and customer services. I became the Billing and Collections Manager in 1995 overseeing all billing and collection activity for the Company. In 1998, I transferred to Appalachian Power Company working in rates. In 2001, I transferred to the AEP Service Corporation working as a Senior Rate Consultant. In July 2004, I assumed the position of Manager, Business Operations Support and was promoted to Director in April 2006. I was promoted to my current position as Managing Director, Regulatory and Finance effective September 1, 2010.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR, REGULATORY AND FINANCE?

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 and certificate of public convenience and necessity ("CPCN") filings before this Commission. I am also responsible for managing the Company's financial operating plans including various capital and O&M operational budgets that interface with all other AEP organizations affecting the Company's performance. As part of the financial strategy, I work with various AEPSC departments to ensure that adequate resources such as debt, equity and cash are available to build, operate, and maintain Kentucky Power's electric system assets providing service to our retail and wholesale customers. In my role as Managing Director, Regulatory and Finance, I report directly to Gregory G. Pauley, President and Chief Operating Officer of Kentucky Power.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified before this Commission in various fuel review proceedings and filed testimony in the Company's three most recent base rate case filings, Case No. 2005-00341, Case No. 2009-00459 and Case No. 2013-00197. Other cases in which I have testified include an environmental compliance plan, Case No. 2011-00401; a real-time pricing proceeding, Case No. 2012-00226; the transfer of the Mitchell Generating Station to Kentucky Power, Case No. 2012-00578; the CPCN filing to convert Big Sandy Unit 1 to gas, Case No. 2013-00430; the current DSM application before the Commission, Case No. 2014-

00271; and the current FAC review before the Commission, Case No. 2014-00225.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to support: (1) the revenue requirement being proposed by the Company; (2) adjustments to the Company's capitalization; (3) certain known and measurable adjustments to test year revenues and operating expenses; and (4) certain tariff revisions.

IV. FILING REQUIREMENTS

Q. PLEASE DESCRIBE SECTION IV OF THE COMPANY'S FILING.

A. Section IV of the Company's filing is the financial exhibit required by the Commission regulation in 807 KAR 5:001, Section 12. Balance sheet data is shown as of September 30, 2014, and income statement data is for the twelve months ended September 30, 2014. This complies with the ninety-day rule set forth in 807 KAR 5:001, Section 12(1)(a).

Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION'S REGULATIONS REQUIRING CERTAIN ADDITIONAL DATA TO BE FILED?

A. Yes. This information required to be filed with a general rate case, including those set forth in 807 KAR 5:001, Section 16, has been incorporated into Section II of the Company's filing.

Q. HAVE YOU PREPARED ANY SCHEDULES OR WORKPAPERS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. The summaries and details of the Capitalization and Rate Base amounts, and the adjustments to the "per books" results of operations that I am sponsoring are set forth in various schedules of Section V of the Company's filing. In particular, I am sponsoring the following Schedules:

- Schedule 1: Fully Adjusted Base Case Summary
- Schedule 2: Revenue Requirement
- Schedule 3: Capitalization
- Schedule 4: Adjustment Summary

I am also sponsoring a number of specific adjustments contained within Schedule 4 (Adjustment Summary) and identify the specific workpaper sheet number where appropriate.

Q. WERE THESE SCHEDULES AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. WHAT INFORMATION ON THE SUMMARIES AND ADJUSTMENTS ARE YOU SPONSORING?

A. I am responsible for the total Company amounts shown or used to derive the Kentucky Power retail jurisdictional amounts. Company Witness Listebarger furnished the Kentucky Power retail jurisdictional amounts and the allocation factors required to calculate such amounts. Company Witness Listebarger is also responsible for the allocation methodology.

V. PROPOSED INCREASE IN ANNUAL REVENUES

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT BEING PROPOSED BY THE COMPANY.

A. The Company is proposing an annual revenue requirement of $630,570,077. This represents an increase of $69,977,002 over the Test Year ended September 30, 2014 adjusted revenues of $560,593,075 or an increase of approximately 12.48%. This annual revenue requirement presumes the Company's proposed treatment of transmission revenues and expenses in base rates ("Transmission Adjustment") is approved by the Commission. Without the proposed Transmission Adjustment, the increase in annual revenue requirement will be $70,103,910 – an increase of approximately 12.51% The derivation of the Transmission Adjustment is described in the testimony of Company Witness Vaughan.

Q. CAN YOU SUMMARIZE THE DEVELOPMENT OF THE PROPOSED ANNUAL REVENUE REQUIREMENT?

A. Kentucky Power's proposed annual revenue requirement is the sum of five distinct components.

First, the annual revenue requirement for base rates was developed. The development of this requirement is shown on Schedule 1 (Fully Adjusted Base Case Summary) of Section V of the Company's filing. Schedule l summarizes the components of Net Electric Operating Income for the twelve months ended September 30, 2014, as adjusted, under present rates in Column 3; and the effects of the proposed rate decrease on those components in Column 4. Also shown are the components of Net Electric Operating Income after giving effect to the proposed rate decrease in Column 5. Finally, the total amount of rate base and capitalization is also shown as well as the calculated overall rates of return.

Q. PLEASE EXPLAIN WHAT SCHEDULE 2 (REVENUE REQUIREMENT) OF SECTION V ILLUSTRATES.

A. Schedule 2 shows how Kentucky Power derived the proposed decrease of $4,696,331 in the Company's annual revenue requirement *without* the proposed Transmission Adjustment.. Schedule 1, Line 24 shows the proposed decrease of $4,823,239 in the Company's annual revenue requirement *with* the proposed Transmission Adjustment.

Q. PLEASE DESCRIBE THE INFORMATION PROVIDED BY SCHEDULES 3 (CAPITALIZATION) AND 4 (ADJUSTMENTS) OF SECTION V.

A. Schedule 3 shows the Company's development of the adjusted capitalization amount used to develop the decrease in annual revenue requirement. Schedule 4 identifies the known and measurable adjustments to test year revenue, expenses and rate base. Details of each adjustment are shown in the workpapers to Schedule 4.

Q. WHAT WAS THE SECOND COMPONENT OF THE COMPANY'S PROPOSED ANNUAL REVENUE REQUIREMENT?

A. Next, pursuant to Paragraphs 4 and 14 of the July 2, 2103 Stipulation and Settlement Agreement in Case No. 2012-00578, Kentucky Power is authorized to recover through a separate rider the Big Sandy Unit 2 retirement costs, as well as the coal-related Big Sandy Unit 1 retirement costs on a levelized basis, including a weighted average cost of capital carry charge, over 25 years. In the Stipulation and Settlement Agreement the Company denominated the rider as Asset Transfer Rider 2 ("A.T.R.-2"); however, the Company is proposing to change the name of this rider to Big Sandy Retirement Rider ("BSRR") to avoid any confusion to the Company's customers as they see specific line items on their bills. The annual BSRR revenue requirement is $21,855,982.

Q, PLEASE EXPLAIN THE NEXT COMPONENT OF THE COMPANY'S ANNUAL REVENUE REQUIREMENT.

A. Third, the Company is proposing to recover through the new Big Sandy Unit 1 Operation Rider ("BS1OR") the following: (1) the non-fuel costs of operating the Big Sandy Unit 1 as a coal facility until the conversion of the unit to natural gas, (2) the non-fuel costs of operating Big Sandy Unit 1 as a natural gas-fired generating station, and (3) the return on and of the capital investment required for the conversion of Big Sandy Unit 1 to a natural gas-fired unit once the gas-fired unit is placed in service. The BS1OR will remain in place until the rates established in the Company's next base rate case become effective. At that time the costs to be recovered through BS1OR will be rolled into base rates and the

BS1OR will be discontinued. The annual revenue requirement for BS1OR, without recovery of any capital costs associated with the conversion of the unit to natural gas, is $18,245,413.

Q. WHAT IS THE NEXT COMPONENT OF THE COMPANY'S ANNUAL REVENUE REQUIREMENT

A. Fourth, pursuant to Paragraph 6 of the Stipulation and Settlement Agreement, Kentucky Power's share of the capital and O&M costs associated with the flue gas desulfurization (FGD) system at the Mitchell station is to be collected through the Environmental Surcharge Tariff and not base rates. As a result this amount was removed from base rates. The annual revenue requirement for the Mitchell FGD to be recovered through the Environmental Surcharge is $34,391,339.

Q. WHAT IS THE FINAL COMPONENT OF KENTUCKY POWER'S ANNUAL REVENUE REQUIREMENT?

A. Finally, the Company is proposing the Kentucky Economic Development Surcharge ("K.E.D.S."), which imposes a $0.15 per month charge on each customer bill that will produce a fund to support needed economic development in the Company's service territory. Based on the test year data, the K.E.D.S. will collect $307,506 annually from the Company's customers. The Company will match the annual amount collected from customers with shareholder funds. Additional information about the K.E.D.S. can be found in the testimony of Company Witness Rogness.

These five components produce a total increase, with the Transmission Adjustment, in the Company's annual revenue requirement of $69,977,002.

Q. WHAT PART OF THE REVENUE REQUIREMENT INCREASE IS RELATED TO THE CHANGES IN KENTUCKY POWER'S GENERATION PORTFOLIO?

A. Kentucky Power's addition of the 50% undivided interest in the Mitchell generating station, the retirement of the coal-related assets at Big Sandy, and the termination of the AEP-East Pool are responsible for approximately $37.7 million dollars of the increase in revenue requirement. This is 54% of the total increase.

Q. WHAT EFFECT ON RATES DOES THE CHANGE IN REVENUE REQUIREMENT DUE TO CHANGES IN THE COMPANY'S GENERATION PORTFOLIO HAVE?

A. The generation portfolio change related revenue requirement increase results in a 6.73 % increase in rates based on the test year revenue.

Q. HOW DOES THE CHANGE IN REVENUE REQUIREMENT DUE TO CHANGES IN THE COMPANY'S GENERATION PORTFOLIO COMPARE WITH THE PROJECTED CHANGE PROVIDED DURING CASE NO. 2012-00578?

A. Calculating the percent increase in revenue requirement arising from the change in the Company's generation portfolio utilizing the Case 2013-00197 jurisdictional revenue amounts results in a non-fuel increase of 6.79%. This compares favorably, on an "apples to apples" basis, with the 8.21% non-fuel increase projected in the Company's response to Staff Data Request 5-10 in Case No. 2012-00578.

Q. IS KENTUCKY POWER PROPOSING TO EQUALIZE RATES OF RETURN ACROSS ALL CUSTOMER CLASSES?

A. No. Kentucky Power is not proposing to equalize its rates of return over all customer classes because the impact of doing so would be significant on certain customer classes, especially residential. As shown in the testimony of Company Witness Stegall, the residential customer class has the lowest rate of return. To equalize the rates of return across classes would result in a far greater increase in rates for the Company's residential customers. The Company is proposing to make a slight movement towards equalizing rates of return across all customer classes.

VI. CAPITALIZATION ADJUSTMENTS

Q. WOULD YOU PLEASE DESCRIBE EACH OF THE CAPITALIZATION ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Yes. The details of the Capitalization adjustments are set forth on Section V, Schedule 3, as follows:

Adjustment	Schedule 3
1. Pro Forma Debt	Column 4
2. Big Sandy Coal Stock	Column 5
3. Big Sandy Coal-Related Assets	Column 6
4. Big Sandy Material & Supplies (M&S)	Column 7
5. Big Sandy CWIP	Column 8
6. Mitchell FGD	Column 9
7. Mitchell Coal Stock	Column 10

8. Franklin Realty Company A/C 124 — Column 11
9. Carrs Site — Column 12
10. Non-Utility Property — Column 13

Q. HOW ARE THE CAPITALIZATION ADJUSTMENTS ALLOCATED AMONG LONG-TERM DEBT, SHORT-TERM DEBT, AND COMMON EQUITY?

A. With the exception of the pro forma debt adjustment and the adjustment relating to coal stocks, the Company allocated the capitalization adjustments ratably among long-term debt, short-term debt, and common equity based on each components percent share of total capitalization at the end of the test year on September 30, 2014. The Company calculated the percentage of short term debt by summing the accounts receivable financing and short-term debt balances on September 30, 2014 and dividing that amount by the total capitalization on September 30, 2014.

Pro Forma Debt Adjustment
(Schedule 3, Column 4)

The Company increased the long-term debt component of its capitalization by a net of $5 million as a result of transactions completed after the end of the test year. The specifics of these transactions are described in more detail in the testimony of Company Witness Reitter.

Big Sandy Coal Stock Adjustment
(Schedule 3, Column 5)

Kentucky Power removed the entire coal inventory at the Big Sandy Plant to comply with the Stipulation and Settlement Agreement. Because the coal inventory is usually financed with short-term debt, the Company made this adjustment to its September 30, 2014 short-term debt.

Big Sandy Coal-Related Asset Adjustment
(Schedule 3, Column 6)

Kentucky Power removed all coal-related assets at the Big Sandy Plant to comply with the Stipulation and Settlement Agreement. The remaining value of the coal assets will be recovered through the BSRR.

Big Sandy M&S Adjustment
(Schedule 3, Column 7)

Kentucky Power removed the entire M&S value at the Big Sandy Plant to comply with the Stipulation and Settlement Agreement. The M&S needed to operate Big Sandy Unit 1 until it is converted to gas and until the Company's next base rate case will be recovered through the BS1OR.

Big Sandy CWIP Adjustment
(Schedule 3, Column 8)

Kentucky Power removed the entire CWIP value at the Big Sandy Plant to comply with the Stipulation and Settlement Agreement. The CWIP needed to operate Big Sandy Unit 1 until it is converted to gas and until the rates established in the Company's next base rate case become effective will be recovered through the BS1OR.

Mitchell FGD Adjustment
(Schedule 3, Column 9)

Kentucky Power removed the entire Mitchell FGD balance from base rates. Those costs will be recovered through the Company's Environmental Surcharge Tariff in compliance with the terms of the Stipulation and Settlement Agreement.

<u>Mitchell Coal Stock Adjustment</u>
<u>(Schedule 3, Column 10)</u>

The coal inventory target at the Mitchell Plant is separately developed for the low and high sulfur coal. On September 30, 2014 the Mitchell Plant had 53,851 tons (Kentucky Power's 50% share) of low sulfur coal on hand at an average cost of $66.77 per ton and a total value (on September 30, 2014) of $3,595,618. The target low sulfur coal inventory is 111,480 tons (Kentucky Power's 50% share). Thus, the difference between the September 30, 2014 low sulfur coal inventory and the target low sulfur coal inventory is 57,629 tons with a value of $3,847,902.

On September 30, 2014 the Mitchell Plant had 110,692 tons (Kentucky Power's 50% share) of high sulfur coal on hand at an average cost of $57.76 per ton and a total value (on September 30, 2014) of $6,393,935. The target high sulfur coal inventory is 55,740 tons (Kentucky Power's 50% share). Thus, the difference between the September 30, 2014 high sulfur coal inventory and the target high sulfur coal inventory is (54,952) tons with a value of ($3,174,393).

The net difference between coal inventory value at Mitchell on September 30, 2014 and the target inventory value $673,509. Because the coal inventory is usually financed with short-term debt, the Company made this adjustment to its September 30, 2014 short-term debt.

<u>Franklin Realty Company Account No. 124 Property</u>
<u>(Schedule 3, Column 11)</u>

The Franklin Realty Company (FRECO) investment, recorded in Account No. 124, was removed from the Company's capitalization.

<u>Carrs Site Adjustment</u>
<u>(Schedule 3, Column 12)</u>

The Carrs Site investment was removed from the Company's capitalization.

<u>Non-Utility Property</u>
<u>(Schedule 3, Column 13)</u>

The Non-Utility property investment was removed from the Company's capitalization.

VII. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. WOULD YOU PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Yes. The details of the revenue and operating expense adjustments are set forth on various pages of Section V, Exhibit 2. Specifically, I am sponsoring the following adjustments:

	Adjustment Name	Adjustment No.
1.	Normalization Major Storms	W13
2.	Amortization Storm Cost Deferral	W14
3.	Amortization of Deferred IGCC Costs	W21
4.	Amortization of Deferred CCS FEED Study	W22
5.	Amortization of Deferred CARRS Site Costs	W23
6.	Amortization of Deferred Preliminary Big Sandy FGD Costs	W24
7.	Mitchell Plant Maintenance Normalization	W34
8.	Amortization of Intangible Plant	W38
9.	Interest Synchronization	W48

10. AFUDC Offset W52

Additional information regarding each of these adjustments is provided below.

<u>Normalization of Major Storms Adjustment</u>
<u>(Section V, Exhibit 2, Adjustment W13)</u>

Q. HOW WAS THE MAJOR STORM NORMALIZATION ADJUSTMENT CALCULATED?

A. The Company adjusted its test year storm damage expense, less in-house labor, by using a three year average storm damage expense, less in-house labor, adjusted by the Handy-Whitman Contract Labor Index. The deferral costs granted in Case No. 2012-00445 were also removed before the 3-year average was calculated. Using the three year average and deducting the test year level of storm damage expense, less deferral, results in a decrease to expenses of $647,763.

<u>Amortization of Major Storm Deferral Adjustment</u>
<u>(Section V, Exhibit 2, Adjustment W14)</u>

Q. HOW WAS THE AMORTIZATION OF MAJOR STORM DEFERRAL ADJUSTMENT CALCULATED?

A. In Case No. 2009-00459, the Commission authorized the Company to defer storm costs totaling $24,492,206 and amortize the recovery of the costs over five years. The amortization of the costs authorized in Case No. 2009-00459 will be complete as of June 2015, and accordingly, the annual amount of $4,698,444 was eliminated from the amortization calculation. In Case No. 2012-00445 the Commission authorized the Company to defer storm costs of $12,146,000 and amortize the costs over five years beginning when the Company’s base rates were next established by the Commission. Accounting for completion of the recovery of the costs that were authorized under Case No. 2009-00459 and the start of recovery of the costs authorized under Case No. 2012-00445, the net adjustment is a reduction of $2,237,475 from the test year.

Amortization of Deferred IGCC Costs
(Section V, Exhibit 2, Adjustment W21)

Q. PLEASE DESCRIBE THE IGCC RELATED COSTS THE COMPANY IS SEEKING TO RECOVER.

A. The Company incurred preliminary engineering and development costs relating to the potential construction and operation of an integrated gasification combined cycle ("IGCC") generation facility in Kentucky. The feasibility of the IGCC facility depended on the Kentucky General Assembly adopting legislation that would support the recovery of the facility's costs through rates. The General Assembly failed to adopt such legislation and, as a result, the facility became uneconomic. The preliminary engineering and development costs were, however, prudently incurred in support of this facility. The Company is seeking to recover these costs amortized over twenty-five years. Company Witness Yoder describes the derivation of the adjustment amount in his testimony.

Amortization of Deferred CCS FEED Study
(Section V, Exhibit 2, Adjustment W22)

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH THE CCS FEED STUDY.

A. As part of its investigations to address emerging environmental regulations, AEP conducted a carbon capture and sequestration ("CCS") study at its Mountaineer generating station in West Virginia. Because the benefits of the study would be enjoyed by each operating company with coal-fired generation, AEP allocated the costs among those companies. The Company is now seeking to amortize and recover its share of the CCS study costs. The Company prudently incurred these costs as part of the investigation of mechanisms to address emerging environmental regulations. The Company is seeking to recover these costs amortized over twenty-five years. Company Witness Yoder describes the derivation of the adjustment amount in his testimony.

Amortization of Deferred CARRS Site Costs
(Section V, Exhibit 2, Adjustment W23)

Q. PLEASE DESCRIBE THE COSTS RELATED TO THE CARRS SITE THE COMPANY IS SEEKING TO RECOVER.

A. As part of its long-term planning, the Company purchased property (the "Carrs Site") in Lewis County, Kentucky as a potential site for a new generation facility. In addition, the Company conducted preliminary site design and engineering work to support developing the property. The Company has elected not to pursue the construction of new generation at the Carrs Site at this time and has removed the land-related costs for this site from rate base. The Company is seeking, however, to recover the engineering and site design costs. The Company prudently incurred these costs as part of its long-term generation resource planning. The Company is seeking to recover these costs amortized over twenty-five years. Company Witness Yoder describes the derivation of the adjustment amount in his testimony.

<u>Amortization of Deferred Preliminary Big Sandy FGD Costs</u>
<u>(Section V, Exhibit 2, Adjustment W24)</u>

Q. PLEASE DESCRIBE THE COSTS INCURRED BY KENTUCKY POWER IN CONNECTION WITH ITS INVESTIGATION OF THE LEAST-COST DISPOSITION OF THE BIG SANDY PLANT IN LIGHT OF ENVIRONMENTAL REQUIREMENTS.

A. Beginning in 2004, the Company began evaluating potential alternatives to comply at the Big Sandy Plant with emerging environmental regulations under the Clean Air Act. This investigation included engineering and design work related to the potential installation of wet and dry flue gas desulfurization systems at the plant. In the end, the Company's evaluation showed that the transfer of a 50% interest in the already-scrubbed Mitchell Plant was the least cost-alternative for the Company and its customers. The Company prudently incurred the preliminary Big Sandy FGD investigation costs as part of its comprehensive evaluation of options to address the effect of emerging environmental regulations at Big Sandy Unit 2.

Q. DID THE COMPANY SEEK RECOVERY OF THE BIG SANDY PRELIMINARY INVESTIGATION COSTS IN CASE NO. 2012-00578?

A. Yes. Kentucky Power sought recovery of the Big Sandy FGD investigation costs in its application in Case No. 2012-00578. The July 2, 2013 Stipulation and Settlement Agreement among Kentucky Power, Kentucky Industrial Utility Customers, Inc. and the Sierra Club contained a provision allowing Kentucky Power to accumulate and defer for review and recovery $28,113,304 of Big Sandy

FGD investigation costs. The agreement further provided that the costs would be recovered over a five year period.

Q. DID THE COMMISSION APPROVE THE JULY 2, 2013 STIPULATION AND SETTLEMENT AGREEMENT WITHOUT MODIFICATION?

A. No, as a condition of its approval of the Stipulation and Settlement the Commission required the Company to agree to four modifications to the agreement. Among these was the elimination of Paragraph 8, which provided for the deferral and recovery of the Big Sandy FGD investigation costs. On October 14, 2013, Kentucky Power filed its written acceptance of the modifications.

Q. WHAT WAS THE COMMISSION'S EXPLANATION FOR REQUIRING THE MODIFICATION OF THE STIPULATION AND SETTLEMENT AGREEMENT?

A. Although the Commission's Order speaks for itself, the following excerpt seems to contain the most important considerations:

> [G]iven the uniqueness of the situation presented herein, the Commission finds that this provision of the Stipulation is not reasonable and should be stricken. We note that the proposed acquisition will result in a 5.33 percent rate increase to Kentucky Power's customers … [during the interim period and] Kentucky Power projects that its ratepayers will see an additional increase of approximately 8.21 percent … [in connection with this application.] The Commission finds that the potential imposition of the $28 million Scrubber Study Costs, in addition to the costs associated with the Mitchell acquisition, is not reasonable, particularly when the Scrubber Study Costs, although spanning a significant period of time, did not result in a formal Kentucky Power proposal upon which the Commission rendered a decision based on its merits. The Commission likewise finds the potential imposition of the Scrubber Study Costs on ratepayers not reasonable due to the fact that a study of this magnitude did not result in the addition of a scrubber of other pollution control facilities at Big Sandy Unit 2.

Q. WHY SHOULD THIS COMMISSION APPROVE THE RECOVERY OF COSTS ASSOCIATED WITH A PROJECT THAT ULTIMATELY WAS NOT CONSTRUCTED?

A. The transfer of the 50% undivided interest in the Mitchell generating station to Kentucky Power first became available in 2012. The cumulative present worth of the Mitchell Transfer, coupled with the conversion of Big Sandy Unit 1 to a natural gas fired unit, was approximately $626 to $819 million less expensive than the cost of retrofitting Big Sandy Unit 2 with a FGD. The Commission recognized this savings in its Order approving the Mitchell Transfer.

In addition, denying recovery of investigation expense because a much less expensive alternative ultimately becomes available discourages the sort of open-minded investigation that yielded the Mitchell Transfer.

Q. WHAT IS THE PROPOSED AMORTIZATION PERIOD FOR THESE COSTS?

A. The Company is seeking to recover over twenty-five (25) years the costs incurred in connection with the Big Sandy Unit 2 FGD investigation. This amortization period corresponds with the expected remaining life of the Mitchell Units. Spreading the costs over this longer period (the Stipulation and Settlement Agreement provided for recovery over a five year period), should address the Commission's concerns about the impact of the request on Kentucky Power's customers.

Mitchell Plant Maintenance Normalization
(Section V, Exhibit 2, Adjustment W34)

Q. HOW WAS THE MITCHELL PLANT MAINTENANCE ADJUSTMENT CALCULATED?

A. Because Kentucky Power plant maintenance is performed on a cyclical basis, an adjustment to the test year plant maintenance expense is required to reflect an annualized on-going level of plant maintenance in the Company's test year cost of service. The Company took the level of Mitchell steam plant maintenance expense for the twelve months ended September 30, 2012, 2013, and an annualized 2014 maintenance expense and adjusted those levels of plant maintenance expense to a constant dollar amount using the Handy-Whitman total steam production plant index. Once the annual constant dollar amounts were calculated, the three year total was divided by three to arrive at an annual normalized level of steam plant maintenance expense of $15,744,373. That result was compared to the test year level amount of $12,474,790. The difference of $3,269,583, when allocated to retail customers based on the PDAF allocation factor, results in an increase to O&M expense to the test year cost of service of $3,223,809.

Q. HAS KENTUCKY POWER HISTORICALLY NORMALIZED STEAM PLANT MAINTENANCE EXPENSES?

A. Yes. In past rate cases, Kentucky Power has historically normalized steam plant maintenance expenses for the Big Sandy Plant.

<u>Amortization of Intangible Plant</u>
<u>(Section V, Exhibit 2, Adjustment W38)</u>

Q. WHY IS INTANGIBLE PLANT AMORTIZATION ANNUALIZED?

A. The Company annualized the September 30, 2014 monthly intangible plant amortization expense and compared the result with the level of intangible plant amortization expense included in the test year. The annualized value better represents the on-going level of expense for intangible plant amortization expense. The effect of this adjustment is to increase Kentucky Power's depreciation expense and decrease the deferred taxes, as explained by Witness Bartsch, by $209,475 and $73,316 respectively.

<u>Interest Synchronization Adjustment</u>
<u>(Section V, Exhibit 2, Adjustment W48)</u>

Q. WHY IS AN INTEREST SYNCHRONIZATION ADJUSTMENT NECESSARY?

A. The purpose of this adjustment is synchronize the capital costs and capital structure included by the Company in this filing with the Federal and State Income Taxes included in the test period cost of service and the interest expense tax deduction that will result. The adjustment resulted in an increase to state income tax of $311,143 and an increase to federal income tax of $1,790,035 for a total increase to expenses of $2,101,178.

<u>AFUDC Offset Adjustment</u>
<u>(Section V, Exhibit 2, Adjustment W52)</u>

Q. PLEASE EXPLAIN THE AFUDC OFFSET ADJUSTMENT.

A. The September 30, 2014 balance of Construction Work In Progress ("CWIP") was used in the determination of Rate Base. The adjustment eliminates all CWIP related to Big Sandy in compliance with the Stipulation and Settlement Agreement. All AFUDC related to Big Sandy is also eliminated. Consistent with prior Commission practice for the Company, an Allowance for Funds Used During Construction (AFUDC) "offset" adjustment is being made to record AFUDC above the line. The non-Big Sandy CWIP balance was $76,287,594 on September 30, 2014, of which $2,007,095 is not subject to AFUDC. The remaining balance of $74,280,499 is subject to AFUDC. Using the requested overall return of 7.71%, the annualized AFUDC is $5,664,029. The AFUDC booked during the test year was $5,521,834 requiring an adjustment to increase the AFUDC offset by $250,424. The Deferred Federal Income Taxes (DFIT) associated with the borrowed funds portion of the $5,664,029 is $748,162. The booked DFIT on the borrowed funds portion was $658,123. This increases DFIT by $90,039.

VIII. TARIFF REVISIONS

System Sales Clause
(Tariff S.S.C.)

Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS TO THE TREATMENT OF SYSTEM SALES OR TARIFF S.S.C. IN THIS PROCEEDING?

A. Yes. First, as has been the practice in past cases, the Company proposes to update the system sales margin amount included as a credit in base rates. This updated system sales margin amount is reflected in Tariff S.S.C., the System Sales Clause. Company Witness Vaughan describes the derivation of the proposed updated system sales margin base rate credit amount in his testimony. The Company is also proposing to return to the same 60/40 customer sharing mechanism found in versions of Tariff S.S.C. in place prior to the changes instituted in accordance with the Stipulation and Settlement Agreement.

Q. HOW WERE FUEL COSTS ALLOCATED IN DETERMINING THE SYSTEM SALES MARGIN BASE RATE CREDIT?

A. Fuel costs were allocated utilizing the Company's historical methodology through which the highest incremental costs are assigned to off-system sales and the remaining costs are assigned to native load customers. As discussed in the Company's most recent fuel adjustment clause review, Case No. 2014-00225, any change to that allocation methodology would result in a corresponding change in the amount of system sales margins to be credited against base rates.

Q. ARE THERE ANY OTHER CHANGES PROPOSED TO TARIFF S.S.C.?

A. Yes. Some wording changes are proposed to reflect the elimination of the Pool Agreement as of January 1, 2014. Kentucky Power's system sales will be as recorded on its books, and references to the AEP System or related allocations are no longer necessary.

Asset Transfer Rider
(Tariff A.T.R.)

Q. WHAT CHANGES ARE BEING PROPOSED TO THE ASSET TRANSFER RIDER (ATR)?

A. Pursuant to Paragraph 4 of the Stipulation and Settlement Agreement, Kentucky Power is entitled to recover through Tariff A.T.R. $44 million annually during the period between January 1, 2014 and the effective date of new base rates that include Mitchell Units 1 and 2. However, because of the lag in cost recovery the

Company will not recover its pro rata share of the $44 million for 2015 if Tariff A.T.R. is terminated at the time new base rates become effective. Accordingly, the Company is proposing to continue Tariff A.T.R. until it recovers its pro rata share of the ordered $44 million. The ATR will terminate once the pro rata share of the annual revenue requirement authorized under tariff ATR is recovered.

Big Sandy Retirement Rider
(Tariff B.S.R.R.)

Q. OTHER THAN THE NAME CHANGE DESCRIBED ABOVE DID THE COMPANY MAKE ANY ADDITIONAL CHANGES TO TARIFF A.T.R.-2 (BSRR)?

A. Yes, upon further review of the Stipulation and Settlement Agreement the Company discovered that the definition of the term "Retirement Costs" included in the agreement was omitted from Tariff A.T.R.-2 attached to the agreement as Exhibit 1-A. The Company has remedied that omission by copying the definition verbatim into Tariff B.S.R.R.

Q. HOW WILL THE COMPANY TRUE-UP THE COSTS ESTIMATED IN THE CALCULATION OF THE REVENUE REQUIREMENT FOR TARIFF B.S.R.R.?

A. At each subsequent base rate case filing, the Company will re-calculate the revenue requirement based upon actual costs incurred versus estimated at the previous base rate case filing, revised estimates for future costs, and any over/under recovery during the current period base rates were in effect. This true-up will then we recovered on a levelized basis over the remaining 25 year life.

<u>Big Sandy Unit 1 Operation Rider</u>
<u>(Tariff B.S.1.O.R.)</u>

Q. WHAT IS THE PURPOSE OF THE BIG SANDY UNIT 1 OPERATION RIDER (BS1OR)?

A. Because of the operational transitions associated with the conversion of Big Sandy Unit 1, and the treatment of Big Sandy coal-related asset retirement costs through the BSRR in accordance with the Stipulation and Settlement Agreement, the Company is proposing to recover the operational costs of Big Sandy Unit 1 as both a coal facility and a converted gas facility via the new Tariff BS1OR. Tariff BS1OR will provide transparency and allow the Commission and other interested parties to review contemporaneously the costs associated with the operation of the unit. Company Witness Vaughan explains how costs included in the BS1OR were calculated. Tariff BS1OR will continue in effect through the natural gas conversion of Big Sandy Unit 1 and until the rates established in the Company's next base rate case become effective. At that time, Tariff BS1OR will be deleted and all operational costs for Big Sandy Unit 1 will again be recovered through base rates.

<u>NERC Compliance and Cybersecurity Rider</u>
<u>(Tariff N.C.C.R.)</u>

Q. WHAT IS THE INTENT OF THE PROPOSED NERC COMPLIANCE AND CYBERSECURITY RIDER?

A. With the increasingly expansive scope of NERC compliance and cybersecurity activities (see Company Witness Stogran's testimony), Kentucky Power is proposing a NERC Compliance and Cybersecurity Rider (NCCR) to serve as a placeholder (established at a level of zero) for the cost of compliance effective July 1, 2015. The intent is, effective with the Commission's approval, to track and defer the capital and operations and maintenance (O&M) expense costs associated with compliance and cybersecurity activities for new NERC requirements or new interpretations of existing requirements. The NERC capital-related costs to be deferred would include carrying costs at the Company's weighted average cost of capital as shown in Section V, Schedule 2. Kentucky Power would in a subsequent proceeding, request recovery for these deferred NERC costs through the NCCR, subject to the Commission's review for prudency.

Q. HAS THE COMMISSION BEEN ACTIVE IN LEARNING ABOUT THE MANY NERC COMPLIANCE AND CYBER SECURITY ISSUES?

A. Yes. I am aware of at least three presentations provided to the Commissioners and the commission staff. First, on December 19, 2013, at the request of the Commissioners, Company Witness Stogran made a confidential presentation overviewing what AEP had been doing to protect itself and its customers across the entire AEP footprint against cyber security attacks. Second, on March 18, 2014 Yulin Bingle, from the Department of Homeland Security made a presentation at the Chairman's Forum addressing cyber security from the Homeland Security perspective. Third, on December 4, 2014 Mike Kormus from PJM made a presentation at another Chairman's Forum addressing cyber security from the PJM perspective. During this presentation, Mr. Kormus made reference to AEP and the excellent work it has been doing for not only its companies, but for the entire utility network across the country.

Q. WHY IS THE NCCR NECESSARY?

A. As detailed in the testimony of Company Witness Stogran, NERC continues to revise existing reliability standards and issue new reliability standards, and a similar or increased level of activity in the future would be difficult to continue to absorb and recover only through base rates. Cybersecurity needs also continue to grow as new threats emerge and new vulnerabilities are identified. The NCCR provides a mechanism for Kentucky Power to recover compliance costs for cybersecurity in a timely fashion.

Q. WHAT WILL BE RECOVERED THROUGH THE NCCR?

A. The NCCR initially would be established at zero as a placeholder. Going forward, the NCCR is intended to recover capital related costs and O&M compliance costs associated with items such as information technology infrastructure, physical security, workforce training, supervisory control and data acquisition (SCADA) systems, smart grid security systems, internal and external audits, external reporting, and recordkeeping. For example, program costs to perform vulnerability assessments due to a specific identified threat could be a type of cost proposed for inclusion in the NCCR. The Company would ensure that only NERC-related capital and O&M costs are recovered through this mechanism.

AEP is at the forefront of industry efforts to plan and prepare for these types of NERC compliance and cybersecurity obligations. Kentucky Power intends to continue planning and preparing for future compliance and cybersecurity obligations, but unforeseen increases in compliance costs cannot simply be absorbed within existing budgets. If new NERC compliance and cybersecurity costs materialize, Kentucky Power will propose to the Commission, in a rider application, recovery of these identified costs through the NCCR. Company witness Rogness discusses the mechanics of how the NCCR will recover the costs associated with these compliance activities in the event that recovery is pursued.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	**)))))))**	**Case No. 2014-00396**

DIRECT TESTIMONY OF

JASON M. YODER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jason M. Yoder, being duly sworn, deposes and says he is Staff Accountant Accounting Policy and Research for American Electric Power Service Corporation and that he has personal knowledge of the set forth in the forgoing testimony for which he is identified as the witness and the information contained therein is true and correct to the best of his information, knowledge and belief.

Jason M. Yoder

Jason M. Yoder

STATE OF OHIO)
) Case No. 2014-00396
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jason M. Yoder, this the 10th day of December, 2014.

Sheryl G. Cleaver

Notary Public

My Commission Expires: June 13, 2017

DIRECT TESTIMONY OF
JASON M. YODER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2014-00396

TABLE OF CONTENTS

DIRECT TESTIMONY OF
JASON M. YODER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Jason M. Yoder. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as a Staff Accountant in Accounting Policy and Research (AP&R). AEPSC is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Kentucky Power Company (Kentucky Power or the Company).

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated with a Bachelor of Science Degree in Accounting from The Ohio State University in 1998 and have been a Certified Public Accountant since 2000. I joined AEPSC, in December 2003 as an Internal Auditor. I transferred to Regulatory Accounting Services (RAS) in August 2010 and transferred to my current position as Staff Accountant in AP&R in November 2014.

Q. WHAT WERE YOUR RESPONSIBILITIES AS STAFF ACCOUNTANT IN RAS AND NOW AS A STAFF ACCOUNTANT IN AP&R?

A. My primary responsibilities in RAS included providing the AEP System operating subsidiaries, including Kentucky Power, with accounting support for regulatory filings. This accounting support includes the preparation of cost of service adjustments, accounting schedules and testimony. As a Staff Accountant in AP&R, I am responsible for performing accounting research, recommending accounting policy and procedures, reporting on the financial effects of potential transactions, and developing accounting instructions for certain non-routine transactions and new accounting rules.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE OTHER UTILITY REGULATORY COMMISSIONS?

A. Yes. I have filed testimony before the Indiana Utility Regulatory Commission in the annual review of Indiana Michigan Power Company's PJM and off-system sales riders. Indiana Michigan Power Company is an affiliate of Kentucky Power.

III. PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my direct testimony is to: (1) support certain known and measurable adjustments to Kentucky Power's operating expenses for the test year ended September 30, 2014; (2) support adjustments for the amortization of various regulatory assets and deferred costs that Company Witness Wohnhas discusses in his testimony; (3) sponsor the annualization of the nine months of actual total costs for the Mitchell Generating Station Units 1 and 2 (Mitchell Plant); (4) support the adjustments to rate base to remove the coal-related Big Sandy Generation Station, Units 1 and 2 (Big Sandy Plant) based on the approved Commission-approved Stipulation and Settlement Agreement in Case No. 2012-

00578 ("Stipulaiton and Settlement Agreement") and discussed further by Company Witness Wohnhas; and (5) support adjustments to remove the Big Sandy Plant related expenses.

In addition to the above, I provide certain components of the coal related retirement costs of Big Sandy Unit 1, retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use (Retirement Costs) including calculation of the Weighted Average Cost of Capital (WACC) carrying charges that are to be recovered over a 25 year period in compliance with the approved Stipulation and Settlement Agreement.

Finally, I discuss over/under deferral accounting for the proposed PJM rider mechanism, the Big Sandy Retirement Rider (BSRR) and the Big Sandy Unit 1 Operation Rider (BS1OR) discussed by Company Witness Vaughan and Company Witness Wohnhas.

With the exception of the components of the Retirement Costs of Big Sandy Plant which are total company amounts, the values I used in my adjustments are Kentucky Power jurisdictional amounts which have been provided by Company Witness Listebarger who supports Kentucky Power's jurisdictional cost of service allocation. The jurisdictional amounts are the Kentucky Power retail portion of the total Company adjustments that I calculated and support.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I prepared the following exhibit JMY-1: Amortization of Coal-Related Big Sandy Retirement and Retirement Related Costs Including Carrying Costs.

IV. OPERATING EXPENSE ADJUSTMENTS

Q. WOULD YOU PLEASE IDENTIFY AND DISCUSS EACH OF THE OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Yes. The details of the operating expense adjustments are set forth on various pages of Section V, Exhibit 2. Specifically, I am sponsoring the following adjustments:

Description	Reference in Section V, Exhibit 2
Amortization of Deferred IGCC Costs	W21
Amortization of Deferred Carbon Capture Costs	W22
Amortization of Deferred CARRS Site Costs	W23
Amortization of Deferred Big Sandy FGD Costs	W24
Incentive Compensation Plan	W25
Annualization of Employee Related Expenses	W26 - 30
Annualization of Mitchell Plant Costs	W33
Reclassification of Cost of Removal Credit	W36
Annualization of ARO Depreciation	W41
Removal of RTO Amortization	W42
Annualization of ARO Accretion	W43

I will provide additional information regarding each of these adjustments below.

Q. PLEASE EXPLAIN THE AMORTIZATION ADJUSTMENTS IN SECTION V, EXHIBIT 2 W21 – W24 THAT YOU ARE SPONSORING?

A. I am sponsoring the amortization of various regulatory assets and deferred costs listed in the table below. The recovery of these assets is supported by Company Witness Wohnhas.

Deferred Cost	Account	Section V, Exhibit 2 Adjustment #	Proposed Amortization Periods (Years)	Annual Jurisdictional Amortization Increase to Expense
IGCC	183	W21	25	$52,505
CCS FEED Study	182.3	W22	25	$34,425
CARRS Site	183	W23	25	$103,330
Preliminary Big Sandy FGD Costs	183	W24	25	$1,105,293

Q. HOW WERE THE ANNUAL AMORTIZATIONS CALCULATED?

A. I obtained the deferred total company balance as of September 30, 2014 for each regulatory asset and deferred cost from Kentucky Power's financial records and divided each of those balances by the proposed 25 year amortization period. The total company annual amortization was jurisdictionalized by Company Witness Listebarger. Company Witness Wohnhas supports the proposed amortization period of 25 years.

Q. WILL THERE BE ANY OVER OR UNDER RECOVERY OF THE AMOUNTS PROVIDED FOR THE RECOVERY OF THE PROPOSED AMORTIZATION OF THESE DEFERRED ASSETS?

A. No. If approved, the amortization will be calculated using the Commission approved amortization periods on a straight-line basis as the recovery is proposed to be included in base rates and not in a separate rider/tracker mechanism.

Q. IS KENTUCKY POWER PROPOSING ANY RECOVERY OF CARRYING CHARGES ON THESE DEFERRED REGULATORY ASSETS AND DEFERRED COSTS?

A. No. Kentucky Power is proposing only to recover the deferred incurred costs, without any carrying charges.

Q. WHAT IS THE PURPOSE OF THE INCENTIVE COMPENSATION ADJUSTMENT IN SECTION V, EXHIBIT 2 W25?

A. The O&M adjustment in Section V, Exhibit 2 W25 decreases Kentucky Power's test year Transmission and Distribution incentive compensation expense by $973,508. This adjustment is necessary to reflect an annual level of incentive compensation expense at a base payout level of one times the incentive target to be paid to employees. Company Witness Carlin discusses the annual incentive compensation plan that this adjustment relates to. Generation was excluded from this adjustment because I sponsor an adjustment to remove Big Sandy Plant expenses and an adjustment to annualize Mitchell Plant expenses in total. These adjustments are discussed later in my testimony.

Q. PLEASE EXPLAIN THE ANNUALIZATION OF EMPLOYEE RELATED EXPENSES IN SECTION V, EXHIBIT 2 W26 – W30.

A. The O&M adjustments in Section V, Exhibit 2 W26 and W27 increase Kentucky Power's payroll labor expense and savings plan expense by $28,383 and $1,193, respectively for a total increase of $29,576. This adjustment annualizes wages and salaries based upon the number of employees and the wages and salaries in effect as of September 26, 2014 which were paid October 3, 2014. Adjustments on pages W28, W29 and W30 increase taxes other than income taxes for Social Security, Medicare and FICA by $1,414, $411 and $5,186, respectively as a result of the increase in payroll on Section V, Exhibit 2 W26. As discussed above in the incentive compensation adjustment, these employee related expenses adjustments also exclude Generation.

Q. WHAT COSTS HAVE YOU ANNUALIZED FOR MITCHELL PLANT?

A. I identified total non-fuel Mitchell Plant costs for the nine months that Mitchell Plant costs were included in the test year as discussed in the section below and annualized them to a twelve month period. My adjustment does not include depreciation expense which is addressed by Company Witness Davis. Additionally, this annualization of Mitchell Plant costs includes taxes other than income taxes but excludes specific adjustments supported by Company Witness Bartsch.

Q. WHAT WERE THE RESULTS OF THE ANNUALIZATION?

A. As shown on Section V, Exhibit 2 W33, Mitchell Plant costs were increased by $10,712,560 ($8,839,850 for operating expenses and $1,872,710 for other taxes). I provided the annualized amounts to Company Witness LaFleur who supports the overall reasonableness of the Mitchell Plant expenses. In addition, I provided Company Witness Wohnhas the maintenance accounts 510 through 514 who calculated a Mitchell Plant maintenance normalization adjustment.

Q. WHAT IS THE PURPOSE OF THE RECLASSIFICATION OF THE COST OF REMOVAL CREDIT ON SECTION V, EXHIBIT 2 W36?

A. This adjustment increases O&M expense by $69,695 and also decreases rate base by the same amount to reflect the reclassification of a credit for removal costs from account 506 to account 108 recorded by Kentucky Power in October 2014. This adjustment corrects an accounting misclassification recorded in the test year which should have been recorded as a credit in account 108 instead of account 506.

Q. PLEASE DESCRIBE THE ANNUALIZATION OF ARO DEPRECIATION EXPENSE IN SECTION V, EXHIBIT 2 W41.

A. This adjustment increases depreciation expense by $237,400 to annualize the ARO depreciation expense by multiplying the September 2014 ARO monthly depreciation expense by twelve for those ARO assets related to the Mitchell Plant, general plant and gas-related assets of Big Sandy Plant. This annualized amount of $605,925 was compared to the test year amount of $365,154 which produced a total company increase of $240,771. The jurisdictionalized amount is the $237,400 increase on Section V, Exhibit 2 W41**.**

Q. WHAT IS THE PURPOSE OF THE REGIONAL TRANSMISSION ORGANIZATION (RTO) AMORTIZATION ADJUSTMENT IN SECTION V EXHIBIT 2 W42?

A. This adjustment reduces expense by $149,718 because a portion of the deferred RTO costs amortized over 10 years will be fully amortized by December 31,

2014. I made no adjustment to the RTO costs amortized over 15 years because the amortization continues until December 2019.

Q. PLEASE DESCRIBE THE ANNUALIZATION OF ARO ACCRETION EXPENSE IN SECTION V, EXHIBIT 2 W43.

A. This adjustment increases other expense by $363,539 to reflect the known amount of ARO accretion expense for October 2014 through September 2015 related to legal obligations as calculated in the Company's PowerPlant accounting system to recognize the interest element of ARO costs.

V. ADJUSTMENT TO REMOVE BIG SANDY O&M AND CERTAIN BIG SANDY RATE BASE ITEMS

Q. WHY IS IT NECESSARY TO MAKE ADJUSTMENTS TO REMOVE BIG SANDY O&M AND CERTAIN BIG SANDY RATE BASE ITEMS?

A. I support adjustments to remove Big Sandy coal-related operating expenses and rate base items. This is done in accordance with the approved Stipulation and Settlement Agreement as discussed by Company Witness Wohnhas. The items are removed because they are subject to recovery through various proposed riders in this case including the BSRR and the BS1OR. The BSRR provides recovery of Big Sandy coal-related Retirement Costs in accordance with the approved Stipulation and Settlement Agreement. I will discuss the components of the BSRR later in my testimony. The proposed BS1OR is to recover the current operating expenses of Big Sandy Unit 1 which is discussed further by Company Witness Vaughan.

Q. WHICH ADJUSTMENTS IN SECTION V, EXHIBIT 2 RELATE TO THE REMOVAL OF BIG SANDY PLANT FROM OPERATING EXPENSES AND RATE BASE?

A. The table below identifies the adjustments that I sponsor related to the removal of Big Sandy Plant.

Description	Reference in Section V, Exhibit 2
Remove Big Sandy Generation Expense	W31
Remove Big Sandy Coal-Related Net Book Value (NBV) from Rate Base	W56
Remove Big Sandy Coal-Related Materials and Supplies (M&S) from Rate Base	W57
Remove Big Sandy Coal-Related Construction Work in Progress (CWIP) and Retirement Work in Progress (RWIP) from Rate Base	W58

Q. HOW WERE BIG SANDY PLANT GENERATION EXPENSES IDENTIFIED AND REMOVED IN SECTION V, EXHIBIT 2 W31?

A. The Kentucky Power generation expenses for the twelve months ended September 30, 2014 included expenses for both the Big Sandy Plant and the Mitchell Plant. I identified Kentucky Power's 50% undivided interest in Mitchell Plant costs and subtracted those expenses from the total generation expenses to get Big Sandy Plant expenses and provided them to Company Witness Vaughan.

Q. HOW DID YOU IDENTIFY MITCHELL PLANT EXPENSES?

A. I obtained the Mitchell Plant joint book billing information which included total billable Mitchell Plant costs and the amount billed to AEP Generation Resources for its 50% undivided interest in the Mitchell Plant. I used this information to determine the amount of Mitchell Plant costs that remained with Kentucky Power for its 50% undivided interest in the Mitchell Plant.

Q. DID THE JOINT BOOK BILLING INFORMATION FROM THE ACCOUNTING RECORDS IDENTIFY ALL THE KENTUCKY MITCHELL PLANT COSTS?

A. No. Further analysis was necessary because not all costs related to Mitchell Plant were processed through the Company's joint book billing process. The joint book billing process identified $20.1 million of the $32.6 million of Mitchell Plant Costs shown on Section V, Exhibit 2 W33 The remaining $12.5 million was mainly for accounts that do not run through the joint book billing process because they are recorded after the joint book billing process is completed during the Company's monthly close process.

Q. WHAT WERE THE TOTAL BIG SANDY COSTS THAT WERE REMOVED?

A. Section V, Exhibit 2 W31 shows that $44,412,600 was identified as Big Sandy costs to be removed. I then provided these amounts to Company Witness Vaughan who performed a study to identify the amount of Big Sandy Unit 1 costs for inclusion in the BS1OR. Big Sandy Unit 2 costs are included in the BSRR and are discussed later in my testimony.

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO REMOVE COAL-RELATED BIG SANDY NBV FROM RATE BASE.

A. To identify the NBV to remove from rate base on Section V, Exhibit 2 W56, the original construction costs were identified from original property records for Big Sandy Unit 1 and Unit 2 by property account. Next, additions greater than $10 million were identified and assigned to each unit. Ratios were then calculated by property account 311 through 316 based on the total costs identified compared to the costs assigned to each unit. Finally, those ratios were applied to the book cost of $551.6 million for Big Sandy Plant as of September 30, 2014. The table below summarizes the results.

Allocation of Big Sandy Plant to Unit 1 and Unit 2

Account	Unit 1	Unit 2	Total
311	$ 11,730,411	$ 31,890,230	$ 43,620,641
312	20,932,300	349,850,013	370,782,313
314	61,210,357	50,669,422	111,879,779
315	3,652,831	12,873,680	16,526,511
316	2,919,986	5,843,495	8,763,481
Total	$ 100,445,885	$ 451,126,840	$ 551,572,725

Q. HOW WERE THE GSU ACCOUNTS 352 AND 353 IDENTIFIED.

A. For accounts 352 and 353 the total cost of the accounts was compared to the costs by Unit and then those ratios were used to allocate the accounts between the units which allocated 37.24% of account 352 and 353 costs to Unit 1 and 62.76% to Unit 2 or $603,417 and $1,016,717, respectively.

Q. ONCE THE BIG SANDY PLANT ORIGINAL COSTS WERE ASSIGNED BETWEEN UNITS 1 AND 2, HOW WERE THE COSTS ASSIGNED TO COAL-RELATED RETIREMENT COSTS?

A. All of Unit 2 which is scheduled to be retired in May 2015, was considered coal related. For Unit 1, the engineering services organization within AEPSC developed percentages of costs by property account that will be retired when the unit is converted to gas. Company Witness LaFleur reviewed these percentages for reasonableness and provided them to me. The jurisdictional amount to remove from rate base for Big Sandy coal-related original cost was $453,590,240.

Q. ONCE THE BIG SANDY PLANT ORIGINAL COSTS WERE ASSIGNED BETWEEN UNITS 1 AND 2 AND IDENTIFIED AS COAL-RELATED RETIREMENT COSTS, HOW WAS THE ACCOMPANYING ACCUMULATED DEPRECIATION CALCULATED?

A. First a reserve ratio for the total Big Sandy Plant was calculated which compared the book accumulated depreciation to the book costs. These ratios were then applied to each Big Sandy Unit original cost identified as coal-related retirement to calculate an accumulated reserve. The jurisdictional net amount to remove from rate base for Big Sandy coal-related accumulated depreciation was $248,316,699.

Q. HOW IS THE JURISDICTIONAL NET RATE BASE REDUCTION ON SECTION V, EXHIBIT 2 W56 CALCULATED?

A. In addition to the original cost of $453,590,240 which is reduced by the accumulated depreciation of $248,316,699, Company Witness Bartsch provided the related removal of Accumulated Deferred Federal Income Tax (ADFIT) of $57,290,476 which provides a net rate base reduction of $147,983,065.

Q. PLEASE DESCRIBE YOUR ADJUSTMENT ON SECTION V, EXHIBIT 2 W57 TO REMOVE BIG SANDY MATERIALS AND SUPPLIES FROM RATE BASE.

A. This adjustment reduces rate base by $6,268,345 for the material and supplies inventory identified as coal-related. The inventory balance as of October 8, 2014 was reviewed by individual inventory item to identify the inventory items that were coal-related. A ratio was then developed comparing inventory identified as coal-related (67.74%) and gas-related (32.26%) to total inventory. The gas-related ratio was then applied to the inventory balance in account 1540001 as of September 30, 2014 to determine the $2,524,107 (total company) amount of inventory to subtract out of total Big Sandy inventory at September 30, 2014 of $8,881,455 (total company) with the resultant jurisdictional amount on Section V, Exhibit 2 W57 being the Big Sandy inventory to remove from rate base.

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO REMOVE BIG SANDY RWIP AND CWIP FROM RATE BASE.

A. On Section V, Exhibit 2 W57, CWIP is reduced by $1,584,601 and account 108 (RWIP) is reduced by $3,720,953. These reductions to rate base were based on a review of the current CWIP and RWIP balances by work order to identify the coal-related work orders.

VI. COMPONENTS OF THE BIG SANDY COAL-RELATED RETIREMENT COSTS TO BE INCLUDED IN THE BIG SANDY RETIREMENT RIDER

Q. WHAT COMPONENTS HAVE YOU IDENTIFIED RELATED TO THE COAL-RELATED RETIREMENT COSTS OF BIG SANDY PLANT TO

BE COLLECTED IN THE BSRR ON A LEVELIZED BASIS OVER 25 YEARS?

A. I have identified the Big Sandy Plant coal-related Retirement Costs defined in the approved Stipulation and Settlement Agreement that is discussed by Company Witness Wohnhas. The components that I have identified are the Retirement Costs of Big Sandy Plant for the net book value, materials and supplies that cannot be used at other plants and removal costs and salvage credits. Additionally, these costs are subject to a WACC and an ADFIT offset.

Q. CAN YOU PLEASE SUMMARIZE THE RETIREMENT COSTS COMPONENTS AND THEIR AMOUNTS?

A. Yes. I have identified each component and its cost in the table below.

Component	Amount
NBV	$201,911,435
Unusable M&S	4,342,987
Removal Costs and Salvage	43,797,850
Ongoing Big Sandy Unit 2 Expense	6,058,782
ARO Costs	56,025,824
less: ADFIT	(72,189,048)
Net Retirement Costs	$239,947,830
Carrying Costs	314,209,917
Total Retirement Costs	$554,157,747
Total Retirement Costs / 25 Years	$22,166,310

Q. ARE THESE VALUES ESTIMATES?

A. Yes. I have obtained the most recent information available and these amounts are the Company's estimates of what the Retirement Costs will be. As shown in the table below, some of these costs are yet to be incurred and in the case of removal and ARO, costs will not be spent for some time into the future.

Components Subject to WACC Return:	Estimated June 30, 2015 Balance	Estimated Future Costs	Grand Total
Components of NBV			
Original Cost	$ 460,030,669	$ -	$ 460,030,669
Accumulated Depreciation	(263,500,120)	-	(263,500,120)
CWIP to transfer to OC	1,607,100	-	1,607,100
RWIP to transfer to AD	3,773,786	-	3,773,786
NBV:	201,911,435		201,911,435
Unusable M&S	4,342,987	-	4,342,987
Removal Costs and Salvage	-	43,797,850	43,797,850
Unit 2 Ongoing Misc. Exp.	-	6,058,782	6,058,782
ARO	1,473,491	54,552,333	56,025,824
ADIT	(72,189,048)	-	(72,189,048)
Total	$ 135,538,865	$ 104,408,965	$ 239,947,830

Company Witness Wohnhas is supporting a periodic true-up for this rider to ensure that the amount collected is based on actual costs. As actual costs are incurred, they will be compared to these estimates and adjustments will be reflected in the BSRR amount to be collected.

Q. HOW WAS THE NBV AMOUNT OBTAINED?

A. To quantify the NBV of Big Sandy Plant, I took the NBV removed from rate base as shown in Section V, Exhibit 2 W56 and calculated depreciation expense for Big Sandy Unit 1 until June 30, 2015 and Big Sandy Unit 2 until May 31, 2015 to rollforward the NBV of each unit. I was provided the depreciation rates by Company Witness Davis. These values are summarized in the table below.

Component	Unit 1	Unit 2	Total
Estimated Cost from Section V, Exhibit 2 W56	$7,870,700	$ 452,159,969	$ 460,030,669
less: Estimated Accumulated Depreciation	5,012,515	258,487,605	263,500,120
Estimated NBV @ June 30, 2015	2,858,185	193,672,364	196,530,549
Big Sandy CWIP @ September 30, 2014			1,607,100
Big Sandy RWIP @ September 30, 2014			3,773,786
Total			$ 201,911,435

Q. WHY IS THE NBV OF EACH UNIT UPDATED TO DIFFERENT PERIODS?

A. Big Sandy Unit 1 was updated to June 30, 2015 because it is the expected NBV prior to the approximate July 1, 2015 effective date for the rates proposed in this proceeding. Big Sandy Unit 2 was updated to May 31, 2015 because that is when the unit will be retired.

Q. PLEASE DESCRIBE THE ESTIMATE FOR UNUSABLE M&S.

A. The process used to determine the value of unusable coal-related M&S was described previously in my testimony where I supported the removal of Big Sandy Plant M&S from rate base. Based on review of historical results from the inventory system, it is anticipated that 15% of the M&S will be either used or transferred by the time the units are shutdown. Of the 85% remaining balance, the salvage value is estimated at 4%. The results are summarized in the table below.

Estimated Coal-Related Inventory at Shutdown

	Unit 1	Unit 2	Total
Estimated Coal Related	$648,925	$4,673,364	$5,322,289
Estimated Usage/Transfer @ 15%	97,339	701,005	798,344
Estimated Value at Shutdown	551,586	3,972,359	4,523,945
Estimated Salvage	4%	4%	
Net Estimated at Shutdown	$529,522	$3,813,465	$4,342,987

Actual results will vary from these estimates. As discussed previously, the actual results will be included in the periodic true-up proposed by Company Witness Wohnhas.

Q. WHAT IS THE BASIS FOR THE REMOVAL COSTS AND SALVAGE CREDITS?

A. I obtained the cost estimate for demolition costs and salvage from the most recent demolition study prepared by Sargent & Lundy, LLC in March 2013 for Big Sandy Plant. The value is the estimated removal costs of total Big Sandy Plant net of the estimated salvage. The cost was then inflated to 2031 in the same manner as the removal cost inflation for the Mitchell Plant described in the testimony of Company Witness Davis.

Q. WHY ARE THERE AMOUNTS FOR ONGOING EXPENSE FOR BIG SANDY UNIT 2?

A. As discussed by Company Witness LaFleur, there are certain ongoing expenses after Big Sandy Unit 2 is shutdown in the amount of $6,058,782 which he provided to me to include in the total costs to be recovered through the BSRR.

Q. PLEASE DESCRIBE THE ADFIT OFFSET AMOUNT.

A. I have calculated the ADFIT using the current statutory federal income tax rate of 35% as applied to the sum total of the NBV of Big Sandy Plant and the unusable M&S. I calculated the ADFIT in this manner as directed by Company Witness Bartsch.

Q. WHAT WACC RATE WAS USED TO CALCULATE CARRYING CHARGES?

A. I calculated carrying charges using the 7.70% WACC presented in this proceeding and sponsored by Company Witness Reitter. A gross-up factor was applied to the appropriate WACC components resulting in a pre-tax WACC of 10.7873%.

Q. HOW WERE THE CARRYING CHARGES CALCULATED AND HOW WILL THE BSRR REVENUES BE COLLECTED BETWEEN PRINCIPAL AND CARRYING CHARGES FOR ACCOUNTING PURPOSES?

A. A yearly summary of the carrying charges is provided on Exhibit JMY-1. The actual calculation will be performed monthly and will calculated on the previous month balance. The increment of the current month net BSRR revenues that exceed the current month carrying charges will be used to reduce the principal balance.

VII. OVER/UNDER RECOVERY OF DEFERRAL ACCOUNTING

Q. WHAT IS THE BASIS FOR OVER/UNDER DEFERRAL ACCOUNTING FOR THE PJM RIDER, BSRR AND BS1OR PROPOSED BY COMPANY WITNESSES VAUGHAN AND WOHNHAS?

A. Financial Accounting Standards Board's Accounting Standards Codification (FASB ASC) 980 requires deferral accounting when a regulatory commission requires future rates to be reduced to refund an over recovery and when a regulatory commission provides for the future recovery of incurred expenses or it is probable that a regulatory commission will provide for such future recovery of an incurred expense. Therefore, in order to record regulatory liabilities or regulatory assets and perform regulatory deferral over/under recovery true-up accounting, it must be probable that the regulatory liability will be refunded or that the regulatory asset will be recovered in the future.

Q. WHAT IS NEEDED TO ESTABLISH PROBABILITY AND THUS MEET THE ACCOUNTING CRITERIA FOR RECORDING A REGULATORY LIABILITY OR ASSET FOR THE FOR THE PJM RIDER, BSRR AND BS1OR PROPOSED BY COMPANY WITNESSES VAUGHAN AND WOHNHAS?

A. In order to meet the probability standard, the final order in this proceeding should clearly provide for both the future recovery or the future refund in the next applicable filing of any difference between incurred expenses (plus a carrying cost where appropriate) compared with the actual revenues collected.

Q. HOW WILL THE OVER/UNDER ACCOUNTING WORK FOR THE BSRR?

A. Regarding the BSRR, the regulatory asset for the costs described previously (or regulatory liability) will be amortized commensurate with the recovery via the BSRR net of carrying charges, Commission fees and bad debt expense over the 25 year recovery period starting July 1, 2014.

Q. HOW WILL THE OVER/UNDER ACCOUNTING WORK FOR THE BS1OR?

A. Regarding the BS1OR, the actual Big Sandy operations expense including depreciation, production O&M and other expenses will be compared to the net monthly revenues collected through the BS1OR with any difference being deferred on the balance sheet as a regulatory asset or regulatory liability.

Q. HOW WILL THE OVER/UNDER ACCOUNTING WORK FOR THE PJM RIDER MECHANISM RECOMMENDED BY WITNESS VAUGHAN?

A. If the monthly actual incurred PJM rider charges and credits are less than the respective monthly amounts (1/12 of Company Witness Vaughan's recommended net level of approximately $74.9 million shown on AEV Exhibit 5) included in the monthly approved revenues, the Company will credit a regulatory liability and charge the appropriate accounts. Similarly, if the monthly actual incurred PJM rider charges and credits are more than the respective monthly amounts as described above, the Company will charge a regulatory asset while crediting the appropriate accounts.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Amortization of Coal-Related Big Sandy Retirement and Retirement Related Costs
Illustrative Example
WACC 10.7873%
Annual Payment $ 22,166,309.89

Year	Bg	Additions	Payments	CC	Ending
1	$135,538,865.72	$19,471,535.00	($22,166,309.89)	$15,228,668.57	$148,072,759.40
2	$148,072,759.40	$12,618,110.00	($22,166,309.89)	$16,300,422.81	$154,824,982.32
3	$154,824,982.32	$14,527,661.00	($22,166,309.89)	$17,163,217.84	$164,349,551.27
4	$164,349,551.27	$8,509,280.00	($22,166,309.89)	$17,936,354.94	$168,628,876.31
5	$168,628,876.31	$2,240,926.00	($22,166,309.89)	$18,102,104.16	$166,805,596.58
6	$166,805,596.58	$368,869.00	($22,166,309.89)	$17,800,011.56	$162,808,167.24
7	$162,808,167.24	$371,840.00	($22,166,309.89)	$17,346,976.26	$158,360,673.61
8	$158,360,673.61	$374,886.00	($22,166,309.89)	$16,842,921.21	$153,412,170.93
9	$153,412,170.93	$378,008.00	($22,166,309.89)	$16,282,070.87	$147,905,939.91
10	$147,905,939.91	$250,000.00	($22,166,309.89)	$15,651,309.58	$141,640,939.59
11	$141,640,939.59	$250,000.00	($22,166,309.89)	$14,941,049.44	$134,665,679.14
12	$134,665,679.14	$250,000.00	($22,166,309.89)	$14,150,267.45	$126,899,636.70
13	$126,899,636.70	$250,000.00	($22,166,309.89)	$13,269,834.88	$118,253,161.68
14	$118,253,161.68	$250,000.00	($22,166,309.89)	$12,289,588.08	$108,626,439.87
15	$108,626,439.87	$250,000.00	($22,166,309.89)	$11,198,211.17	$97,908,341.15
16	$97,908,341.15	$250,000.00	($22,166,309.89)	$9,983,105.37	$85,975,136.62
17	$85,975,136.62	$43,797,850.00	($22,166,309.89)	$10,849,167.77	$118,455,844.50
18	$118,455,844.50	$0.00	($22,166,309.89)	$12,299,827.71	$108,589,362.32
19	$108,589,362.32	$0.00	($22,166,309.89)	$11,181,269.28	$97,604,321.70
20	$97,604,321.70	$0.00	($22,166,309.89)	$9,935,900.40	$85,373,912.21
21	$85,373,912.21	$0.00	($22,166,309.89)	$8,549,344.64	$71,756,946.95
22	$71,756,946.95	$0.00	($22,166,309.89)	$7,005,595.71	$56,596,232.77
23	$56,596,232.77	$0.00	($22,166,309.89)	$5,286,832.69	$39,716,755.56
24	$39,716,755.56	$0.00	($22,166,309.89)	$3,373,214.31	$20,923,659.97
25	$20,923,659.97	$0.00	($22,166,309.89)	$1,242,649.92	$0.00
		$104,408,965.00	$554,157,747.34	$314,209,916.61	

Estimated June 30, 2015 Beginning Costs	$135,538,865.72
Additions	104,408,965.00
Subtotal	$239,947,830.72
Carrying Costs	$314,209,916.61
Total Estimated Costs	**$554,157,747.34**