BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

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PUBLIC SERVICE COMMISSION

IN THE MATTER OF

GENERAL ADJUSTMENTS IN ELECTRIC RATES OF KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY OF TIMOTHY C. MOSHER

ON BEHALF OF KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
TIMOTHY C. MOSHER, ON BEHALF OF
KENTUCKY POWER COMPANY
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TABLE OF CONTENTS

**DIRECT TESTIMONY OF
TIMOTHY C. MOSHER, ON BEHALF OF
KENTUCKY POWER COMPANY,
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
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I. Introduction

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

A: My name is Timothy C. Mosher. My position is President and Chief Operating Officer, Kentucky Power Company (Kentucky Power, KPCo 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 in Electrical Engineering degree from the University of Detroit in 1969 and an MBA from the University of Akron in 1974. In 1981 I attended an AEP Management Program at the University of Michigan. I also attended the Executive Program at the Darden Graduate School of Business Administration at the University of Virginia in 1995.

Q: PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A: I have spent my entire career as an employee of American Electric Power and its subsidiaries. I became President of Kentucky Power Company on June 1, 2004. Prior to that time I served as State President - Kentucky for American Electric Power from 1996-2004. Between 1974 and 1995, I served in various managerial and administrative positions with two subsidiaries of American Electric Power (Central Region Manager, Columbus Southern/Ohio Power Company, Zanesville, Ohio (1992-1995); Zanesville Division Manager, Ohio Power Company, Zanesville, Ohio (1989-1992); Marketing and Customer Services Manager, Ohio Power Company, Canton Division (1987-1989); Administrative Assistant, Governmental Affairs, Ohio Power Company (1981-1987); Area Manager, Ohio Power Company, Kenton, Ohio (1978-1981); Customer Engineering Services Manager, Ohio Power Company, Steubenville Division (1977-1978); Administrative Assistant – Industrial, Ohio Power Company, Canton General Office (1974-1977). I joined AEP in 1970 and worked as a power engineer for Ohio Power Company, Canton Division between 1970 and 1974.

Q: **WHAT ARE YOUR MAIN RESPONSIBILITIES AS PRESIDENT OF THE COMPANY?**

A: My principal responsibility is to guide the management of the distribution operation of the Company. In that regard, I work with and oversee the Company's regulatory affairs, governmental/environmental affairs, business operations support, corporate communications and customer operations. My job is to ensure our corporate mission of providing reliable, timely service to our customers at the lowest reasonable cost. I am also responsible for assuring that the Company's obligations to our employees, to the customers we serve, and to our shareholders are fulfilled. Finally, I maintain relationships with the management teams responsible for the generation and transmission functions in Kentucky.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A: Yes. I filed testimony in case No. 2005-00341 and have participated in many technical and informal conferences at the Commission.

III. Purpose of Testimony

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: I will give an overview of the Company and its current application to set retail rates that will provide an additional $123.6 million in annual revenue. I also will identify the major features of the rate application, and place the filing in a historical context. Finally, I will comment upon the Company's performance over the past several years.

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

A: Kentucky Power is a wholly owned subsidiary of American Electric Power, Inc. (AEP) and is engaged in the generation, purchase, transmission and distribution of electric power. The Company serves approximately 175,000 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 to the City of Olive Hill and the City of Vanceburg. Exhibit TCM-1 is a map detailing the Company's service territory in Kentucky. The Company maintains a state office in Frankfort, Kentucky, which houses the office of the 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.

Q: MR. MOSHER, WHY IS KENTUCKY POWER SEEKING TO ADJUST ITS RATES?

A: Despite increasing efficiencies, and enhanced reliability projects, Kentucky Power's rates no longer permit the Company to recover the costs of providing quality service to its customers and to provide its shareholders with a fair and reasonable rate of return on their investment. Kentucky Power last filed for general rate relief as a base rate case in 2005, Case No. 2005-00341. Since the last general rate case, almost all of the Company's expenses have increased, including but not limited to, specialized safety equipment and wearables, computers and computerized systems for data collection, training programs, service vehicles, fuel for the vehicles, radio equipment, power tools, and employee costs including wages and healthcare benefits. Increased costs and lost revenues have reduced the Company's return on equity below levels that permit Kentucky Power to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed. For the test year ended September 30, 2009, Kentucky Power's return on equity was 2.90%. The cost information presented in this application concerning our test year and the adjustments to those numbers justify the requested increase in this case. In light of increasing environmental requirements, Kentucky Power would have been forced to seek a general adjustment to its base rates much sooner but for its ability to recover some of those costs through the environmental surcharge tariff (Case No. 2005-00068; Case No. 2006-00307; Case No. 2006-00128; Case No. 2007-00381; Case No. 2009-00038; and Case No. 2009-00316).

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

A: The Company is proposing to increase rates by approximately $123.6 million annually. This increase is based on adjusted data for the historic test year of twelve months ended September 30, 2009, and known and measurable changes occurring after the test year. The major components of the rate increase which are detailed in the testimonies of other witnesses referenced later are as follows:

(a) Additional Reliability Expense;

(b) Wind Purchase Power Agreement;

(c) Increased Depreciation Rates and Annualization;

(d) Off System Sales Tracker Adjustment;

(e) Return on Common Equity of 11.75%.

Q: WHY IS KENTUCKY POWER INCLUDING A WIND POWER PURCHASE AGREEMENT (Wind PPA) OF 100 MW IN THIS CASE?

A: In November 2008, Governor Steven Beshear unveiled a state comprehensive energy plan entitled *Intelligent Energy Choices for Kentucky's Future* which identified six immediate challenges for Kentucky:

- Meet Kentucky's needs for 40% more energy by 2025
- Develop clean, reliable, affordable energy sources
- Improve our energy security

- Diversify our energy portfolio
- Reduce carbon dioxide emissions
- Provide economic prosperity

To address these challenges, the Governor presented seven strategies. One of those strategies is to increase the use of renewable energy with the following goal: "By 2025, Kentucky's renewable energy generation will triple to provide the equivalent of 1,000 megawatts of clean energy while continuing to produce safe, abundant, and affordable food, feed and fiber." This strategy was presented as a portion of a proposed Renewable and Efficiency Portfolio Standard, whereby twenty-five percent of Kentucky's energy needs in 2025 will be met by reductions through energy efficiency and conservation and through the use of renewable resources. Eighteen percent is expected to be achieved through energy efficiency while the remaining seven percent will be met through the use of renewable resources such as solar, wind, hydro, and biofuels.

American Electric Power, the parent of Kentucky Power, has identified a 100 MW wind power purchase opportunity for Kentucky Power which moves the company in the direction of the Governor's energy plan. As detailed in the testimony of Witness Godfrey, AEP now has 1296.1 MW of long-term renewable wind energy resources under contract. We currently generate 1060 MW at our coal burning Big Sandy plant in Louisa, Kentucky (Unit 1-260 MW; Unit 2-800 MW), and have 393 MW under contract through 2022 at the Rockport, Indiana, coal burning plant. That 1453 MW total is 232 MW short of our all time winter peak of 1685 MW set in January 2005. To meet the needs of our customers in excess of our owned or contracted capacity, we rely on capacity and energy purchases from our sister AEP-East operating companies (Ohio Power Company, Columbus Southern Company, Appalachian Power Company, Indiana Michigan Power Company) in accordance with the 1951 AEP Interconnection Agreement (AEP Pool). The Wind PPA of 100 MW will assist Kentucky Power in filling the gap between its owned or contracted capacity and its winter peak as well as contribute to AEP's strategic goal to address Green House Gasses (GHG) by including 2,000 MW of renewable energy resources in the generation portfolio by the end of 2011. Kentucky Power's IRP filing in August 2009 included 100 MW of renewable energy. Witness Weaver's testimony offers an economic analysis in support of the approval of this Wind PPA.

Q: WHY IS KENTUCKY POWER REQUESTING ADDITIONAL FUNDS FOR DISTRIBUTION RELIABILITY?

A: The details of the request for incremental distribution reliability funds can be found in Witness Phillips' testimony. The request is based upon a distribution system reliability enhancement program that addresses increased vegetation management. The proposed program includes moving to a four-year maintenance cycle; establishing a ten-year cycle for our pole inspection program; installing SCADA (Supervisory Control and Data Acquisition) equipment in additional substations; and hiring additional employees to both meet the increased maintenance requirements and to address an aging work force issue in this highly skilled area.

Q: **WHAT TESTIMONY IS BEING FILED BY KENTUCKY POWER IN SUPPORT OF ITS APPLICATION?**

A: The Company's proposed adjustments to test year revenues, operating expenses, rate base and capitalization are sponsored by the witnesses and their respective subject areas listed below:

Name	**Subject Area**
William E. Avera	Cost of Equity
Dennis W. Bethel	Transmission Adjustment Tariff
Jay F. Godfrey	Wind Generation
Diana L. Gregory	Accounting for Transmission Adjustment Tariff
James E. Henderson	Depreciation Study
Daniel E. High	Class Cost of Service
David A. Jolley	Employee Compensation
Hugh E. McCoy	Pension Plan Costs
Thomas M. Myers	Sharing of Off-System Sales
Everett G. Phillips	Distribution Reliability
David M. Roush	Rate Design and Tariffs and Revenue Adjustment
Errol K. Wagner	Jurisdictional Study and Revenue and O&M
Scott C. Weaver	Net Cost of Wind Generation
Ranie K. Wohnhas	O&M Expenses

Q: **ARE THE REQUESTED RATES FAIR, JUST AND REASONABLE?**

A: Yes. Kentucky Power's goal is to provide reliable and cost-effective service while producing a reasonable return to its stockholders. Prior to 2009, Kentucky Power has been able to accomplish these objectives, through effort, efficiencies and commitment – plus some favorable economic circumstances. Times have changed, though. Customers have greater expectations, governments are setting higher standards, and the Company's earnings have deteriorated. As a result, Kentucky Power's rates are no longer fair, just, and reasonable. Kentucky Power has filed this request for rate relief to obtain fair, just, and reasonable rates that will enable it to continue to provide the service and earnings that customers and stockholders deserve and require.

Q: DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes.

AFFIDAVIT

Timothy C. Mosher, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

T. C. Mosher

Timothy C. Mosher

Commonwealth of Kentucky)
) Case No. 2009-00459
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Timothy C. Mosher this 18th day of December 2009.

Judy K Rosquist

Notary Public

My Commission Expires January 23, 2013

AEP Service Territory in Kentucky

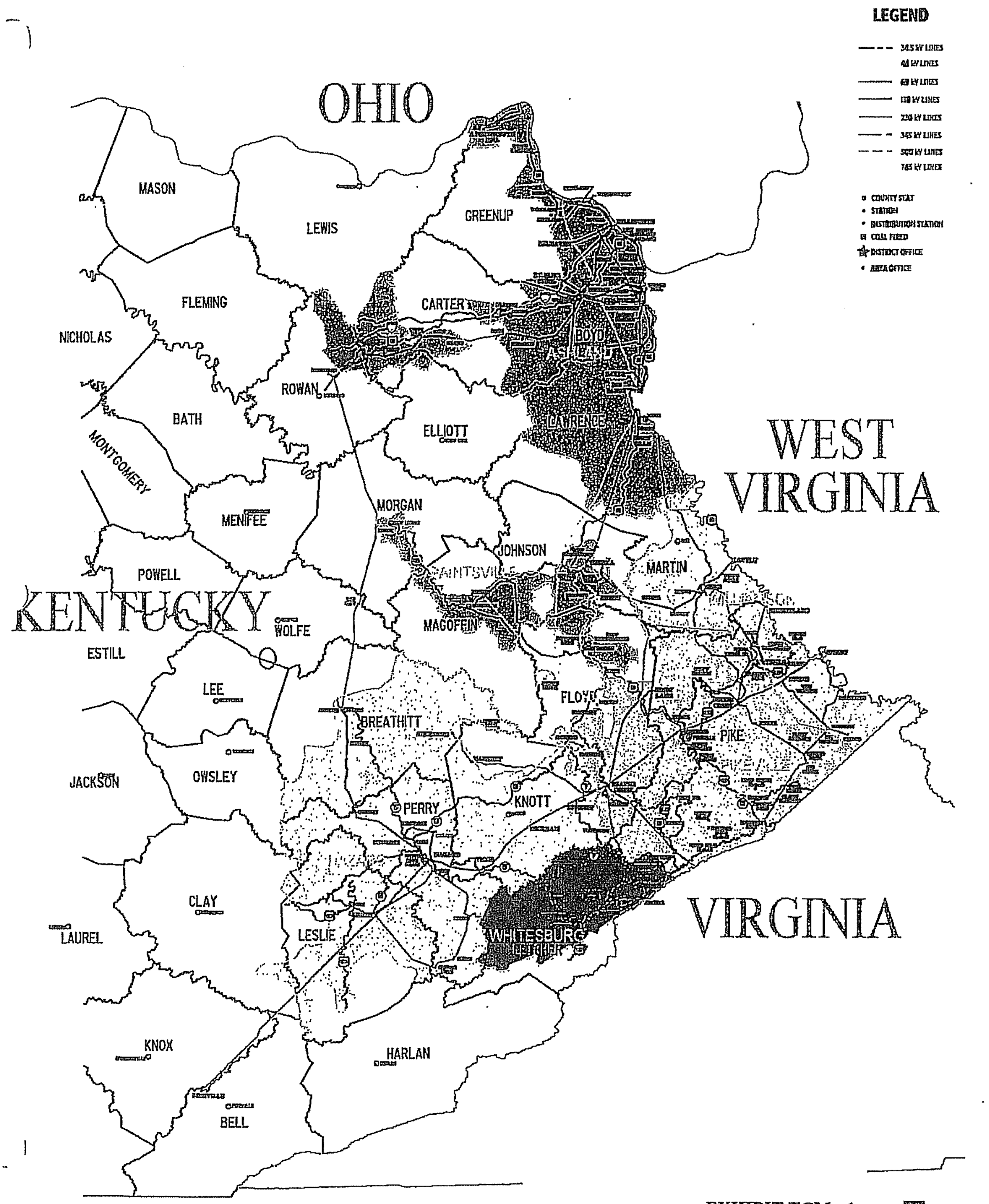

EXHIBIT TCM - 1

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY
OF
WILLIAM E. AVERA

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Qualifications

Q. 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, including the Public Service Commission of the Commonwealth of Kentucky ("KPSC" or "the Commission").

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 as Exhibit WEA-1.

B. Overview

Q. What is the purpose of your testimony?

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

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to KPCo and its parent company, American Electric Power Company, Inc. ("AEP"). I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for KPCo, and they form the basis of my analyses and conclusions.

Q. What is the role of the ROE in setting utility 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. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] 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.

Q. How is your testimony organized?

A. I first reviewed the operations and finances of KPCo and the current conditions in the electric utility industry and the capital markets. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), as well as reference to expected earned rates of return for utilities. Based on the cost of equity estimates indicated by my analyses, KPCo's ROE was evaluated taking into account the specific risks and

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

potential challenges for its jurisdictional electric utility operations in Kentucky, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity.

C. Summary of Conclusions

Q. What are your findings regarding the fair rate of return on equity for KPCo?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend an ROE for KPCo from the middle of my 10.95 percent to 12.55 percent reasonable range, or 11.75 percent. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with KPCo's jurisdictional utility operations, my analyses focused on a proxy group of twenty other utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the DCF and CAPM methods, as well as the expected earnings approach, to estimate a fair ROE for KPCo;
- Based on my evaluation of the strength of the various methods, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.8 percent to 12.4 percent range, or 10.95 percent to 12.55 percent after incorporating a minimum adjustment to account for the impact of common equity flotation costs;
- Investors view existing cost recovery mechanisms as supportive of KPCo's financial integrity, but there is no evidence that these provisions will result in a measurable change in the Company's investment risk or ROE relative to the proxy companies;

- The reasonableness of an 11.75 percent ROE for KPCo is also supported by the exposures associated with environmental mandates and the need to support access to capital.

Q. What other evidence did you consider in evaluating your ROE recommendation in this case?

A. My recommendation is reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity; and,
- Providing KPCo with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

Q. What is your conclusion as to the reasonableness of KPCo's capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of 42.91 percent represents a reasonable capitalization for KPCo. This conclusion was based on the following findings:

- The common equity ratio implied by KPCo's capital structure is consistent with the capitalizations maintained by the proxy group of electric utilities based on data at year-end 2008 and near-term expectations;
- The additional leverage implied by KPCo's obligations under operating leases warrant a more conservative financial posture; and,
- The requested capitalization reflects the need to support the credit standing and financial flexibility of KPCo as the Company seeks to fund system investments and meet the requirements of customers.

II. 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 KPCo. In addition, it examines the risks and prospects for the electric utility industry and 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 rate of return.

A. Kentucky Power Company

Q. Briefly describe KPCo.

Q. Headquartered in Frankfort, Kentucky, KPCo is principally engaged in the generation, transmission, and distribution of electric power. The Company provides electric service to approximately 176,000 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. Sales to residential customers comprised 40 percent of retail revenues, with 24 percent to commercial, and 36 percent to industrial and other end-users. At year-end 2008, KPCo's total assets amounted to $1.5 billion, with total revenues amounting to approximately $692 million.

KPCo operates approximately 1,060 megawatts (MW) of coal-fired generating capacity and, along with other operating subsidiaries of AEP, is party to an interconnection agreement that defines how they share the costs and benefits associated with their respective generating plants. KPCo'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 RTO, and provides transmission service pursuant to the PJM Open Access Transmission Tariff (OATT). The Company's retail utility operations are subject to the jurisdiction of the KPSC, with wholesale transmission operations being regulated by the 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 nearly 38,000 MW of generating capacity and over 251,000 miles of transmission and distribution lines. AEP's electric utility subsidiaries rely primarily on coal-fired generation, which makes up approximately 65 percent of total system capacity. During 2008, AEP's revenues totaled approximately $14.4 billion, with total assets at year-end of $45.2 billion.

Q. Where does KPCo obtain the capital used to finance its investment in electric utility plant?

A. As a wholly-owned subsidiary of AEP, KPCo 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, KPCo also issues debt securities directly under its own name.

Q. What credit ratings have been assigned to KPCo?

A. Currently, KPCo is assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation (S&P), with Moody's Investors Service (Moody's) assigning an issuer rating of "Baa2". These ratings are identical to those assigned to KPCo's parent, AEP. Meanwhile, Fitch Ratings Ltd. (Fitch) has assigned a "BBB-" issuer default rating to KPCo, while rating AEP one notch higher at "BBB".

B. Risks for KPCo

Q. How have investors' risk perceptions for the utility industry evolved?

A. Implementation of structural change and related events have caused investors to rethink their assessment of the relative risks associated with the utility industry. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. S&P recently reported that the majority of the companies in the utility sector now fall in the triple-B rating category.[3] Going forward, Fitch concluded that the short- and long-term outlook for investor-owned electric utilities is negative,[4] while Moody's observed, "Material negative bias appears to be developing over the intermediate and longer term due to rapidly rising business and operating risks."[5] Similarly, S&P observed that:

> Credit markets are tight. Liquidity is constrained. And construction, labor, and material costs are soaring. As if that weren't enough, the U.S. electric utility sector also faces aging infrastructure, declining capacity margins, and increasing environmental compliance requirements.[6]

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[3] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric Utility Sector's Liquidity Remains Adequate In Third Quarter 2009," (Sep. 21, 2009).

[4] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

[5] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[6] Standard & Poor's Corporation, "Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings," *RatingsDirect* (Mar. 9, 2009).

Q. Does KPCo anticipate the need for additional capital going forward?

A. Yes. KPCo will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund new investment in electric generation, transmission and distribution facilities. AEP noted in its most recent Form 10-Q Report that it plans to invest an additional $1.8 billion in utility assets during 2010 alone.[7] Support for KPCo's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund its share of these projects in an effective manner.

Q. Is the potential for energy market volatility an ongoing concern for investors?

A. Yes. In recent years utilities and their customers have had to contend with dramatic fluctuations in energy costs due to ongoing price volatility in the spot markets, and investors recognize the prospect of further turmoil in energy markets. Moody's has warned investors of ongoing exposure to "extremely volatile" energy commodity costs, including purchased power prices, which are heavily influenced by fuel costs,[8] and Fitch noted that rapidly rising energy costs created vulnerability in the utility industry.[9]

For example, while coal has historically provided relative stability with respect to fuel costs, the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE), reported that prices for Central and Northern Appalachia coal spiked from approximately $45 per ton in June 2007 to over $140 per ton in September 2008, before

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[7] American Electric Power Company, Inc., *Form 10-Q Report* (Sep. 30, 2009).

[8] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).

[9] Fitch Ratings Ltd., "Staying Afloat: Downstream Liquidity in the Energy and Power Sectors," *Oil & Gas / Global Power Special Report* (June 16, 2008).

falling back into the $40 to $50 range in September 2009.[10] The power industry and its customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets. Moody's concluded that natural gas "remains highly volatile," and warned that such price fluctuations "could have a significant impact on a utility's liquidity profile."[11]

While expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. Indeed, Fitch highlighted the challenges that such dramatic fluctuations in commodity prices can have for utilities and their investors and recently noted that "uncertainty regarding fuel prices, in particular natural gas costs, has made planning for the future even more problematic."[12] The rapid rise in electricity costs that can result from higher wholesale energy prices has heightened investor concerns over the implications for regulatory uncertainty. S&P noted that, while timely cost recovery was paramount to maintaining credit quality in the electric power sector, an "environment of rising customer tariffs, coupled with a sluggish economy, portend a difficult regulatory environment in coming years."[13]

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[10] Energy Information Administration, *Coal News and Markets* (Jun. 20 & Sep. 26, 2008, Oct. 13, 2009).
[11] Moody's Investors Service, "Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector," *Special Comment* (March 2009).
[12] Fitch Ratings, Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).
[13] Standard & Poor's Corporation, "Top 10 U.S. Electric Utility Credit Issues For 2008 And Beyond," *RatingsDirect* (Jan. 28, 2008).

Q. Do the KPSC's adjustment mechanisms protect KPCo from exposure to fluctuations in power supply costs?

A. To a limited extent, yes. The investment community views KPCo's ability to periodically adjust retail rates to accommodate fluctuations in fuel and purchased power as an important source of support for KPCo's financial integrity. Nevertheless, they also recognize that there can be a lag between the time KPCo actually incurs the expenditure and when it is recovered from ratepayers. As a result, KPCo is not insulated from the need to finance deferred power production and supply costs. Indeed, despite the significant investment of resources to manage fuel procurement, investors are aware that the best that KPCo can do is to recover its actual costs. In other words, KPCo earns no return on fuel costs and is exposed to disallowances for imprudence in its fuel procurement.

Q. What other financial pressures impact investors' risk assessment of KPCo?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. As Moody's observed:

> [P]ressures are building. Utilities are facing rising operating costs and infrastructure investment needs that are prompting them to seek more-frequent requests for rate relief. Meanwhile, as energy (and other commodity) costs rise, so does the risk of a consumer backlash over electric rates that could prompt legislative intervention or a more contentious atmosphere between utilities and their regulators.[14]

[14] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

Similarly, S&P noted that "heavy construction programs," along with rising operating and maintenance costs and volatile fuel costs, were a significant challenge to the utility industry.[15] Fitch echoed this assessment, concluding:

> Continued access to capital at reasonable rates in 2009 remains uncertain at a time when many utility holding groups have historically high capital investment programs and will require ongoing access to reasonably priced capital in order to fund new investment and refinance maturing debt.[16]

As noted earlier, investors anticipate that KPCo and AEP will undertake significant electric utility capital expenditures. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on the Company.

Q. Are environmental considerations also affecting investors' evaluation of electric utilities, including KPCo?

A. Yes. Although KPCo's exposure is moderated through the Environmental Cost Compliance ("ECC") surcharge in Kentucky, utilities are confronting increased environmental pressures that could impose significant uncertainties and costs. In early 2007 S&P cited environmental mandates, including emissions, conservation, and renewable resources, as one of the top ten credit issues facing U.S. utilities.[17] Similarly, Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for

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[15] Standard & Poor's Corporation, "Ratings Roundup: Utility Sector Experienced Equal Number Of Upgrades And Downgrades During Second Quarter Of 2008," *RatingsDirect* (Jul. 22, 2008).
[16] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).
[17] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

electric utilities,"[18] while Fitch observed that "the structure, timing and implementation is still uncertain."[19]

At the national level, the Obama administration has taken a far more active stance towards energy and environmental policy. It has endorsed the American Clean Energy and Security Act of 2009 ("ACES"), passed by the House of Representatives on June 26, 2009. In addition to creating a comprehensive, economy-wide cap-and-trade regulatory framework, ACES would reduce carbon emissions 17 percent by 2020 compared to 2005 levels and require electric utilities to meet 20 percent of their electricity needs from renewable sources by 2020. Compliance with these evolving standards will undoubtedly require significant capital expenditures, especially for utilities like KPCo that depend significantly on coal-fired generation. S&P concluded, "Although we expect the cap-and-trade program to be economywide and affect a variety of sectors, it will disproportionately affect the power sector."[20] S&P recently emphasized that because of uncertainty over the details and timing of future limits on CO_2 emissions, existing ratings do not fully reflect the impact of carbon risks.[21]

D. Impact of Capital Market Conditions

Q. What are the implications of recent capital market conditions?

A. The financial and real estate crisis that accelerated during the third quarter of 2008 led to unprecedented price fluctuations in the capital markets as

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[18] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).
[19] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).
[20] Standard & Poor's Corporation, "The Potential Credit Impact Of Carbon Cap-And-Trade Legislation On U.S. Companies," *RatingsDirect* (Sep. 14, 2009).
[21] *Id.*

investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase.

With respect to utilities specifically, as of September 30, 2009, the Dow Jones Utility Average stock index remained almost 30 percent below the level in June 2008. This sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry was not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to congressional representatives as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[22]

Similarly, an October 1, 2008, *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.[23]

An October 2008 report on the implications of credit market upheaval for utilities noted that even high-quality companies "now have to pay an

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[22] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).
[23] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).

unusually high risk premium over Treasuries."[24] Meanwhile, a Managing Director with Fitch Ratings, Ltd. ("Fitch") observed that, "significantly higher regulated returns will be required to attract equity capital."[25] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions has increased the cost of capital for utilities:

> While credit is available to investment-grade issuers in the utilities, power and gas sectors, it is more expensive, particularly when viewed against the easy money environment which prevailed for most of this decade.[26]

Fitch recently concluded, "While utilities maintained relatively good market access during the credit crisis, the cost of capital is higher than prior to the credit crisis, and bank credit remains relatively tight."[27]

Q. Has the economy in KPCo's service territory felt the impact of the global recession?

A. Yes. Investors recognize that electric utilities such as KPCo are not immune to the declining sales and cash flow that accompanies an economic downturn. The economy in eastern Kentucky has been hard-hit during the ongoing recession. For example, the unemployment rate in eastern Kentucky's Magoffin County reached nearly 17 percent in April 2009, with Fitch noting, "The primary rating concerns facing [KPCo] relate to its

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[24] *Rudden's Energy Strategy Report* (Oct. 1, 2008).
[25] Fitch Ratings Ltd., "EEI 2008 Wrap-Up: Cost of Capital Rising," *Global Power North America Special Report* (Nov. 17, 2008).
[26] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).
[27] Fitch Ratings Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).

exposure to a struggling local economy, particularly the industrial sector which comprises 36 percent of retail revenues."[28] Similarly, Moody's noted that Kentucky was in the midst of "a deep protracted recession," and that "[a]cute economic recessionary pressures" were a key ratings driver for KPCo.[29]

Q. What do these events imply with respect to the ROE for KPCo?

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would fluctuate as dramatically as they did. While conditions in the economy and capital markets appear to have stabilized, investors are apt to react swiftly and negatively to any future signs of trouble in the financial system or economy. Given the importance of reliable electric power for customers and the economy, it would be unwise to ignore investors' increased sensitivity to risk in evaluating KPCo's ROE.

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of common equity for benchmark groups of comparable risk firms and evaluate expected earned

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[28] Fitch Ratings, Ltd., "Kentucky Power Co.," *Global Power U.S. and Canada Credit Analysis* (Sep. 11, 2009).

[29] Moody's Investors Service, "Credit Opinion: Kentucky Power Company," *Global Credit Research* (Feb. 02, 2009).

rates of return for utilities. Finally, I 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 return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. 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. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment 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:

$$k_i = R_f + RP_i$$

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. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is generally 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. 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. 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.

Q. Did you rely on a single method to estimate the cost of common equity for KPCo?

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[30]

Therefore, I applied both the DCF and CAPM methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

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[30] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at Part 2, p. 4 (1997).

Q. Does the fact that there are different accepted methods to estimate the cost of common equity, each based on certain assumptions, imply that determining the ROE is subjective?

A. Absolutely not. The alternative approaches that I have applied to estimate the cost of common equity have considerable theoretical and practical support, and the body of knowledge on the topic of cost of capital attests to the significance of developing cost of capital estimates that work in the real world of financial markets. For example, the reality that investors require compensation for bearing the risk of putting their money in common stock is a fundamental tenet of the theory and practice of finance. While assumptions and judgment underlie these methods to estimate the cost of common equity, this does not imply that they are subjective or that the cost of common equity is unknowable.

Each method of estimating the cost of common equity is based on empirical evidence and accepted applications. While experts may disagree on particular nuances and details of their application, the reliability of these methods is confirmed by their use throughout the regulatory arena as well as in the worlds of investment management and corporate finance. The fact that alternative methods may give somewhat different results, or that different experts may come to different estimates using these methods, does not mean the methods are subjective or unreliable. It means simply that interpreting the results of these methods requires care and practical judgment.

B. Comparable Risk Proxy Groups

Q. How did you implement these quantitative methods to estimate the cost of common equity for KPCo?

A. Application of the DCF model and other 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 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 the DCF model and other quantitative methods 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 KPCo's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies classified by The Value Line Investment Survey ("Value Line") as electric utilities with: (1) S&P corporate credit ratings of "BBB-" to "BBB+," (2) a Value Line Safety Rank of "2" or "3", and 3) a Value Line Financial Strength Rating of "B++" or higher. These criteria resulted in a proxy group composed of twenty companies, which I will refer to as the "Utility Proxy Group."

Q. What other proxy group did you consider in evaluating a fair ROE for KPCo?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. As noted in *Regulatory Finance: Utilities' Cost of Capital,* "It should be emphasized that the definition of a comparable risk class of companies does not entail similarity of operation, product lines, or environmental conditions, but rather similarity of experienced business risk and financial risk."[31] Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. What criteria did you apply to develop the Non-Utility Proxy Group?

A. My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: 1) pay common dividends; 2) have a Safety Rank of "1"; 3) have investment grade credit ratings from S&P, and 4) have an S&P Stock Quality Ranking of "B" or higher. In addition, I included only those firms with published earnings per share ("EPS") growth projections from at least two of the following sources: Value Line, Thomson Reuters ("IBES"),[32] First Call Corporation ("First Call"), and Zacks Investment Research ("Zacks").

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[31] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 58 (1994).

[32] Thomson Reuters separately compiles and publishes consensus securities analyst growth rates under the IBES (formerly Institutional Brokers Estimate System) and First Call brands.

Q. Do these criteria provide objective evidence to evaluate investors' risk perceptions?

A. Yes. 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.*, "A+") 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.

The 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.

Q. **How do the overall risks of your proxy groups compare with KPCo?**

A. As shown below, Table WEA-1 compares the utility proxy group with the non-utility proxy group and KPCo across four key indicators of investment risk. Because the Company has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, AEP:

TABLE WEA-1
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
	Credit Rating	Safety Rank	Financial Strength	Beta
Utility Group	BBB	2	B++	0.74
Non-Utility Proxy Group	A	1	A+	0.79
KPCo	BBB	3	B++	0.70

Q. **Does this comparison indicate that investors would view the firms in your proxy groups as risk-comparable to KPCo?**

A. Yes. As discussed earlier, KPCo, like its parent, AEP, is rated "BBB" by S&P, which is identical to the average corporate credit rating for the utilities in the Utility Proxy Group. Similarly, the average Financial Strength Rating of "B++" for the Utility Proxy group is the same as that assigned to AEP. And while AEP's Safety Rank of "3" indicates greater risk than for the proxy group of utilities, its lower beta value suggests somewhat less risk. Considered together, a comparison of these objective measures, which consider of 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 KPCo are comparable to those of the firms in the Utility Proxy Group.

With respect to the Non-Utility Proxy Group, its average credit ratings, Safety Rank, and Financial Strength Rating suggest less risk than for KPCo, with its 0.79 average beta indicating greater risk. While any differences in investment risk attributable to regulation should already be reflected in these objective measures, my analyses nevertheless conservatively focus on a lower-risk group of non-utility firms.

C. 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 general form of the DCF model is expressed 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:[33]

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

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

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[33] 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.

return in the form of current dividends and the remainder through price appreciation.

Q. What form of the DCF model did you use?

A. I applied the constant growth DCF model to estimate the cost of common equity for KPCo, which is the form of the model most commonly relied 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 (D_1/P_0) 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, and more controversial, 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 was the dividend yield for the Utility Proxy Group determined?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the utility proxy group are presented on Exhibit WEA-2. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 2.4 percent to 6.6 percent.

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. Are historical growth rates likely to be representative of investors' expectations for utilities?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this 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 ratio for electric utilities falling from approximately 80 percent historically to on the order of 60 percent.[34] 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.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[35]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based

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[34] The Value Line Investment Survey (Sep. 15, 1995 at 161, Dec. 26, 2008 at 687).

[35] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).

primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[36]

The fact that investment advisory services focus primarily on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[37] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[38]

In 2007, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[39]

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[36] The Value Line Investment Survey, *Subscriber's Guide* at 53.

[37] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

[38] *Id.* at 88.

[39] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).

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. 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 Utility Proxy Group reported by Value Line, IBES, First Call, and Zacks are displayed on Exhibit WEA-2.

Q. Some argue that analysts' assessments of growth rates are biased. Do you believe these projections are inappropriate for estimating investors' required return using the DCF model?

A. No. 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 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 (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. 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 *Regulatory Finance: Utilities' Cost of Capital*:

> 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 also 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].[40]

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[40] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 154 (1994).

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 seldom, if ever, 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.

Accordingly, while I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, I have included the "sustainable growth" approach for completeness. 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.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the Utility Proxy Group?

A. The sustainable, "br+sv" growth rates for each firm in the Utility Proxy Group are summarized on Exhibit WEA-2, with the underlying details being presented on Exhibit WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. What other growth rate did you consider?

A. As noted earlier, the DCF model assumes that investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation. Consistent with this paradigm, I also examined expected growth in each utility's stock price based on Value Line's 2011-2014 projections.

Q. What cost of common equity estimates were implied for the Utility Proxy 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 Exhibit WEA-2.

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. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. 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 senior, long-term debt. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

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. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[41]

More recently, in its March 27, 2009 decision in *Pioneer*, FERC concluded that it would exclude low-end ROEs "within about 100 basis points above the cost of debt."[42]

Q. What does this test of logic imply with respect to the DCF results for the Utility Proxy Group?

A. The average corporate credit rating associated with the firms in the Utility Proxy Group is "BBB". Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging 6.14 percent in October 2009.[43] As highlighted on Exhibit WEA-2, three of the individual equity estimates for the firms in the Utility Proxy Group exceeded this threshold by approximately 100 basis points, with another falling below the yield available on triple-B utility bonds.[44] In light of the risk-return tradeoff principle and the test applied in *Pioneer*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a

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[41] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.
[42] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 94 (2009) ("*Pioneer*").
[43] Moody's Investors Service, www.credittrends.com.
[44] As highlighted on Exhibit WEA-2, these DCF estimates ranged from 4.1 percent to 7.2 percent.

utility's securities. As a result, consistent with the test of economic logic applied by FERC, this value provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. Do you also recommend excluding estimates at the high end of the range of DCF results?

A. Yes. The upper end of the cost of common equity range produced by the DCF analysis presented in Exhibit WEA-2 was set by a 25.1 percent estimate for Allegheny Energy, Inc. In addition to this extreme outlier, I determined that, when compared with the balance of the remaining estimates, six other DCF estimates should also be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of the DCF model.[45]

Q. What cost of common equity estimates are implied by your DCF results for the Utility Proxy Group?

A. As shown on Exhibit WEA-2 and summarized in Table WEA-2, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates ranging from 10.1 percent to 12.4 percent, and generally trending toward 10.8 percent:

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[45] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

TABLE WEA-2
DCF RESULTS – UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	10.1%
IBES	10.6%
First Call	10.4%
Zacks	11.1%
br+sv	10.8%
Stock Price	12.4%

Q. What were the results of your DCF analysis for the Non-Utility Proxy Group?

A. I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Utility Proxy Group. The results of my DCF analysis for the Non-Utility Proxy Group are presented in Exhibit WEA-4, with the sustainable, "br+sv" growth rates being developed on Exhibit WEA-5. As shown on Exhibit WEA-4 and summarized in Table WEA-3, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates generally in the 12 percent to 13 percent range:

TABLE WEA-3
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.4%
IBES	12.4%
First Call	12.8%
Zacks	13.0%
br+sv	12.3%
Stock Price	12.4%

As discussed earlier, reference to the Non-Utility Proxy 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.

D. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are 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. 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 CAPM 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 CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. How did you apply the CAPM to estimate the cost of common equity?

A. Application of the CAPM to the Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit WEA-6. 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 dividend paying firms in the S&P 500.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-half of the growth rate discussed subsequently (1 + *g*) to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the earnings 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 348 individual firms, current estimates imply an average growth rate over the next five years of 9.2 percent. Combining this average growth rate with an adjusted dividend yield of 2.7 percent results in a current cost of common equity estimate for the market as a whole of approximately 11.9 percent. Subtracting a 4.2 percent risk-free rate based on the average yield on 20-year Treasury bonds produced a market equity risk premium of 7.7 percent.

Q. What was the source of the beta values you used to apply the CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> 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. . . . Value Line is the largest and most widely circulated independent investment advisory service, and exerts influence on a large number of institutional and individual investors and on the expectations of these investors.[46]

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[46] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* at 65 (1994).

As shown on Exhibit WEA-6, multiplying the 7.7 percent market risk premium by the respective Value Line betas for the firms in the Utility Proxy Group, and then adding the resulting risk premiums to the average long-term Treasury bond yield, results in an average indicated cost of common equity of 9.9 percent.

Q. What cost of common equity was indicated for the Non-Utility Proxy Group based on this forward-looking application of the CAPM?

A. As shown on Exhibit WEA-7, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 10.3 percent.

Q. Do you have any observations regarding these CAPM results?

A. Yes. Applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased. Thus, recent capital market conditions may cause CAPM cost of common equity estimates to understate investors' required returns for common stocks, particularly when historical data are used to calculate the market risk premium. While my application of the CAPM makes every effort to incorporate investors' forward-looking expectations, the full effect of the "flight to safety" may not be captured in my market risk premium estimate.

Second, the beta in CAPM theory is a measure of the investors' expected relationship of a firm's stock price to the market as a whole. Because investors' expected beta for a firm is not known, reported betas are estimated based on historical relationships. The precipitous drop and subsequent partial recovery in stock prices over the last year or so have caused many firms' historical betas to become unstable, so that reported betas may or may not reflect investors' expected beta. Because of this inherent mismatch between the historical circumstances underlying reported beta values and the current perceptions of investors, the CAPM may not accurately reflect investor's forward-looking rate of return requirements.

Meanwhile, forward-looking estimates of the market required rate of return may be distorted by the recent run-up in stock prices. It is not clear whether reported security analysts' dividend and growth projections have kept pace with the economic recovery expectations presumably pushing up stock prices; if not, there is a mismatch that under-estimates of the market required rate of return. This incongruity between current measures of the market risk premium and historical beta values is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently. As a result, there is every indication that CAPM approaches fail to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

E. Expected Earnings Approach

Q. What other analyses did you conduct to estimate the cost of common equity?

A. As I noted earlier, I 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 rates of return on equity are indicated for utilities based on the expected earnings approach?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5 percent in 2009, and 11.0 percent in 2010 and over its 2012-2014 forecast horizon.[47] Meanwhile, for the firms in the Utility Proxy Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on Exhibit WEA-8. 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-3. As shown on Exhibit WEA-8,

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[47] The Value Line Investment Survey at 2232 (Nov. 6, 2009).

Value Line's projections for the utility proxy group suggested an average ROE of 11.3 percent.

F. Summary of Quantitative Results

Q. Please summarize the results of your quantitative analyses.

A. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-4, below:

A. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-4, below:

TABLE WEA-4
SUMMARY OF QUANTITATIVE RESULTS

DCF	**Utility**	**Non-Utility**
Value Line	10.1%	11.4%
IBES	10.6%	12.4%
First Call	10.4%	12.8%
Zacks	11.1%	13.0%
br+sv	10.8%	12.3%
Stock Price	12.4%	12.4%
CAPM	9.9%	10.3%
Expected Earnings		
Electric Utilities - 2009	10.5%	
Electric Utilities - 2010	11.0%	
Electric Utilities - 2012-14	11.0%	
Utility Proxy Group	11.3%	

As noted earlier, because the capital market crisis and ensuing recovery have created a number of problems in applying the CAPM, I largely disregarded the resulting cost of equity estimates. Based on my assessment of the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity indicated by my analyses is in the 10.8 percent to 12.4 percent range.

G. 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 amount of funds a utility nets 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. Has AEP recently issued additional common equity?

A. Yes. On April 7, 2009 AEP closed on the sale of 69 million shares of common stock. With the net proceeds raising approximately $1.64 billion of additional equity capital, AEP's stock sale constituted the largest in the utility industry since 1995.[48] Thus, in addition to flotation costs associated with past equity issues, AEP also incurred issuance costs associated with its recent sale of new common shares. Furthermore, in June 2009 KPCo received $30 million in equity capital from AEP.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of 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

[48] Katz, David M. and Marie Leone, "How AEP Finance Chief Drove Jumbo Stock Offering," *CFO.com* (Apr. 8, 2009).

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.[49]

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%,[50] with AEP incurring issuance costs equal to approximately 3.02 percent of the gross proceeds from its 2009 public offering.[51] Applying this 3.0 percent expense percentage for AEP to a representative dividend yield of 5.0 percent implies a minimum flotation cost adjustment on the order of 15 basis points.

Q. What then is your conclusion regarding a fair ROE based on your analyses for the companies in your proxy groups?

A. After incorporating a minimum adjustment for flotation costs of 15 basis points to my "bare bones" cost of equity range, I concluded that a fair ROE for the proxy group of electric utilities is currently in the 10.95 to 12.55 percent range.

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[49] Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, 1994, at 166.

[50] *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%.

[51] American Electric Power Company, Inc., *Prospectus Supplement (To Prospectus dated December 22, 2008)* (Apr. 1, 2009).

IV. RETURN ON EQUITY FOR KENTUCKY POWER CO.

Q. What is the purpose of this section?

A. In addition to presenting my conclusions regarding a fair ROE for KPCo, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of KPCo's requested capital structure and examine the implications of cost adjustment mechanisms for the Company's ROE.

A. Implications for Financial Integrity

Q. Why is it important to allow KPCo an adequate ROE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While the Company remains committed to providing reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of the pressures associated with ongoing capital expenditure requirements, uncertain environmental compliance costs, and the potential for continued energy price volatility. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on KPCo and its parent, AEP. Indeed, despite the dramatic and sustained fall in utility stock prices, AEP issued new common shares even at depressed prices in order to meet its capital needs and support financial strength. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These considerations heighten the importance of allowing KPCo an adequate ROE.

Q. What role does regulation play in ensuring that KPCo has access to capital under reasonable terms and on a sustainable basis?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, the continuation of supportive regulation remains crucial to the Company's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Fitch noted that:

> Regulatory risk remains a recurring theme for this year's outlook, as the pressure of a weak economic backdrop could result in political push-back to rate increase requests.[52]

[52] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

The report went on to conclude, "Fitch is concerned that the recent rapid escalation in the cost of capital will not be reflected on a timely basis in utility rates."[53] Moody's has also emphasized the need for regulatory support, concluding:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[54]

Similarly, S&P concluded, "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[55]

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. Providing a return on fair value that is both commensurate with those available from investments of corresponding risk and sufficient to maintain KPCo's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* and *Hope* decisions; but it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired and service quality is compromised.

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[53] *Id.*
[54] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).
[55] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

B. Capital Structure

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 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 implicit in KPCo's requested capital structure?

A. The Company's capital structure is presented in Workpaper S-2, page 1 of 3. As summarized there, common equity as a percent of the capital sources used to compute the overall rate of return for KPCo was 42.91 percent.

Q. How can the Company's requested capital structures be evaluated?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other electric utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

Q. What was the average capitalization maintained by the Utility Proxy Group?

A. As shown on Exhibit WEA-9, for the firms in the Utility Proxy Group, common equity ratios at December 31, 2008 ranged between 39.4 percent and 65.4 percent and averaged 47.6 percent of long-term capital.

Q. What capitalization is representative for the Utility Proxy Group going forward?

A. As shown on Exhibit WEA-9, Value Line expects an average common equity ratio for the Utility Proxy Group of 51.1 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 43.0 percent to 68.0 percent.

Q. What implication does the increasing risk of the utility industry have for the capital structure maintained by KPCo?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the ongoing 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.

Moody's has warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[56] Moody's noted that, "maintaining unfettered access to capital markets will be crucial," and cited the importance of forestalling future downgrades by bolstering utility balance sheets.[57] As Moody's concluded:

> Our concerns are clearly growing, but we believe utilities have adequate time to adjust and revise their corporate finance polices and strengthen balance sheets, thereby improving their ability to manage volatility and address uncertainty.[58]

Similarly, in a review of the analytical methodology underlying its ratings assessment, S&P characterized a debt-to-total capital ratio in the range of 50 percent to 60 percent as "Aggressive",[59] and noted, "A total debt to capitalization level of 50% or greater is generally considered to be aggressive to highly leveraged for utilities."[60] Moody's affirmed that because of its significant investment plans, the utility industry "will need to attract a significant amount of new equity capital in order to maintain existing ratings."[61]

Q. How does KPCo's common equity ratio compare with those maintained by the reference group of utilities?

A. KPCo's 42.91 percent common equity ratio falls below the 47.6 percent average for the Utility Proxy Group at year-end 2008. Similarly, KPCo's requested equity ratio is well short of the 51.1 percent equity ratio based on

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[56] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).
[57] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).
[58] *Id.*
[59] Standard & Poor's Corporation, "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," *RatingsDirect* (May 27, 2009).
[60] Standard & Poor's Corporation, "Ratings Trend Turns Negative During First Quarter Of 2009 For U.S. Electric Utilities," *RatingsDirect* (Apr. 14, 2009).
[61] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

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.

C. Impact of Trackers

Q. Does the fact that KPCo operates under certain rate adjustment mechanisms warrant any adjustment in your evaluation of a fair ROE?

A. No. Investors recognize that KPCo is exposed to significant risks associated with energy price volatility and rising costs and concerns over these risks have become increasingly pronounced in the industry. The KPSC's rate adjustment mechanisms are a valuable means of mitigating those risks, but they do not eliminate them. For example, despite the fact that KPCo is able to recover incremental environmental costs through the ECC, Fitch noted the potential for regulatory lag and concluded, "Significant cost recovery delays or disallowances of future environmental costs could place downward pressure on ratings."[62] While the adjustment mechanisms approved for KPCo partially attenuate exposure to attrition in an era of rising costs, this leveling of the playing field only serves to address factors that could otherwise impair KPCo's opportunity to earn its authorized return, as required by established regulatory standards.

Reflective of this industry trend, the companies in the Utility Proxy Group operate under a wide variety of cost adjustment mechanisms, which range from riders to recover bad debt expense and post-retirement

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[62] *Wireless News*, "Fitch Affirms Kentucky Power Co.'s Ratings; Outlook Stable" (Aug. 24, 2009).

employee benefit costs to revenue decoupling and adjustment clauses designed to address the rising costs of environmental compliance measures. Similarly, the firms in the Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether. As a result, the mitigation in risks associated with utilities' ability to attenuate the risk of cost recovery is already reflected in the cost of equity range determined earlier, and no separate adjustment to KPCo's ROE is necessary or warranted.

D. Return on Equity Range Recommendation

Q. Please summarize the results of your analyses.

A. In order to reflect the risks and prospects associated with KPCo's jurisdictional utility operations, my analyses focused on a proxy group of twenty other utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sectors of the economy. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-4, which is reproduced below:

TABLE WEA-4
SUMMARY OF QUANTITATIVE RESULTS

DCF	**Utility**	**Non-Utility**
Value Line	10.1%	11.4%
IBES	10.6%	12.4%
First Call	10.4%	12.8%
Zacks	11.1%	13.0%
br+sv	10.8%	12.3%
Stock Price	12.4%	12.4%
CAPM	9.9%	10.3%
Expected Earnings		
Electric Utilities - 2009	10.5%	
Electric Utilities - 2010	11.0%	
Electric Utilities - 2012-14	11.0%	
Utility Proxy Group	11.3%	

As noted earlier, based on my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of common equity indicated by my analyses is in the 10.8 percent to 12.4 percent range, or 10.95 percent to 12.55 percent after incorporating a minimum adjustment for flotation costs.

Q. What other considerations are reasonably considered in establishing a fair ROE range for KPCo?

A. 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 recession ends and the economy returns to a more normal pattern of growth. This implies that the cost of permanent capital, including common equity, will be higher in the upcoming years than it is currently.

Q. How do current interest rates on long-term bonds compare with those projected for the next few of years?

A. Table WEA-5 below compares current interest rates on 30-year Treasury bonds, double-A rated utility bonds, and triple-A rated corporate bonds with those projected for 2008 through 2011 by Value Line,[63] GlobalInsight,[64] , and the EIA:[65]

TABLE WEA-5
INTEREST RATE TRENDS

	Oct. 2009	2010	2011	2012	2013
30-Yr. Treasury					
Value Line	4.2%	4.8%	4.5%	5.1%	5.5%
GlobalInsight	4.2%	3.8%	4.9%	5.0%	5.2%
AA Utility					
GlobalInsight	5.2%	6.2%	6.5%	6.4%	6.7%
EIA	5.2%	6.1%	6.8%	6.6%	6.8%
AAA Corporate					
Value Line	5.2%	5.9%	5.8%	6.2%	6.7%
GlobalInsight	5.2%	5.4%	6.0%	6.0%	6.2%

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2010-2013 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. What then is your conclusion as to a fair ROE for KPCo?

A. Considering capital market expectations, the potential exposures faced by KPCo, and the economic requirements necessary to maintain financial

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[63] The Value Line Investment Survey, *Forecast for the U.S. Economy* (Aug. 28, 2009).
[64] GlobalInsight, *The U.S. Economy: The 30-Year Focus* (First Quarter 2009).
[65] Energy Information Administration, *Updated Annual Energy Outlook 2009* (Mar. 2009).

integrity and support additional capital investment even under adverse circumstances, it is my opinion that 11.75 percent represents a fair and reasonable ROE for KPCo.

My conclusion is reinforced by the need to consider the potential exposures faced by KPCo and the economic requirements necessary to maintain financial integrity and support access to capital even under adverse circumstances. In addition, KPCo faces ongoing uncertainties related to future emissions legislation. Coupled with the need to provide an ROE that supports KPCo's credit standing while funding necessary system investments, these considerations indicate that an ROE from the middle of my recommended range is reasonable. The cost of providing the Company an adequate return is small relative to the potential benefits that a strong utility can have in providing reliable service. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation is crucial.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF TEXAS

CASE NO. 2009-00459

COUNTY OF ~~HAYS~~ TRAVIS

AFFIDAVIT

William E. Avera, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

William E. Avera

Subscribed and sworn to before me by William E. Avera this 8th day of December 2009.

Notary Public

CHARLES SMAISTRLA
Notary Public, State of Texas
My Commission Expires
JAN. 14, 2012

My Commission Expires 1/14/12

WILLIAM E. AVERA

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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 (over 150 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, 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 (88 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

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.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; 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 Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed 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

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

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)

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"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

"Estimating Utility Cost of Equity in Financial Turmoil", SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 5, 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)

DCF MODEL

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(b)	(g)	(g)	(g)	(g)	(g)	(g)
		Dividend Yield			Growth Rates						Cost of Equity Estimates					
	Company	Price	Dividends	Yield	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
1	Allegheny Energy	$ 25.35	$ 0.60	2.4%	7.5%	16.0%	11.0%	16.0%	9.5%	22.7%	9.9%	$\boxed{18.4\%}$	13.4%	$\boxed{18.4\%}$	11.9%	$\boxed{25.1\%}$
2	ALLETE	$ 34.96	$ 1.79	5.1%	-1.0%	6.0%	5.0%	4.0%	4.8%	3.4%	$\boxed{4.1\%}$	11.1%	10.1%	9.1%	9.9%	8.5%
3	Alliant Energy	$ 27.28	$ 1.55	5.7%	4.5%	4.4%	4.4%	4.5%	4.6%	11.7%	10.2%	10.1%	10.1%	10.2%	10.3%	$\boxed{17.4\%}$
4	Ameren Corp.	$ 25.03	$ 1.54	6.2%	1.0%	3.0%	3.0%	3.5%	3.6%	10.6%	$\boxed{7.2\%}$	9.2%	9.2%	9.7%	9.8%	16.8%
5	American Elec Pwr	$ 30.20	$ 1.64	5.4%	3.0%	3.8%	3.5%	3.3%	6.0%	8.9%	8.4%	9.2%	8.9%	8.7%	11.4%	14.3%
6	Edison International	$ 32.35	$ 1.26	3.9%	4.5%	3.0%	3.0%	5.0%	7.8%	11.5%	8.4%	$\boxed{6.9\%}$	$\boxed{6.9\%}$	8.9%	11.7%	15.4%
7	FirstEnergy Corp.	$ 43.99	$ 2.20	5.0%	4.0%	5.0%	5.0%	7.0%	7.3%	12.3%	9.0%	10.0%	10.0%	12.0%	12.3%	$\boxed{17.3\%}$
8	OGE Energy Corp.	$ 34.82	$ 1.44	4.1%	4.5%	4.8%	4.8%	6.0%	6.9%	3.5%	8.6%	8.9%	8.9%	10.1%	11.0%	7.7%
9	Otter Tail Corp.	$ 23.55	$ 1.21	5.1%	4.0%	7.8%	5.0%	11.7%	3.6%	6.2%	9.1%	12.9%	10.1%	16.8%	8.7%	11.4%
10	PG&E Corp.	$ 41.62	$ 1.77	4.3%	6.5%	7.0%	6.5%	7.5%	6.7%	3.4%	10.8%	11.3%	10.8%	11.8%	10.9%	7.6%
11	Portland General Elec.	$ 19.92	$ 1.04	5.2%	3.5%	7.4%	6.0%	6.7%	3.7%	5.8%	8.7%	12.6%	11.2%	11.9%	9.0%	11.1%
12	PPL Corp.	$ 29.84	$ 1.49	5.0%	7.5%	12.5%	12.5%	10.0%	9.4%	10.8%	12.5%	$\boxed{17.5\%}$	$\boxed{17.5\%}$	15.0%	14.4%	15.8%
13	Progress Energy	$ 37.32	$ 2.48	6.6%	6.0%	4.4%	4.0%	4.5%	3.2%	3.3%	12.6%	11.0%	10.6%	11.1%	9.8%	9.9%
14	P S Enterprise Group	$ 29.76	$ 1.38	4.6%	7.5%	5.3%	4.0%	5.3%	8.3%	10.9%	12.1%	9.9%	8.6%	9.9%	12.9%	15.5%
15	SCANA Corp.	$ 34.70	$ 1.91	5.5%	4.0%	4.5%	5.0%	4.5%	5.9%	8.2%	9.5%	10.0%	10.5%	10.0%	11.5%	13.7%
16	Sempra Energy	$ 51.75	$ 1.68	3.2%	5.5%	6.3%	7.0%	7.0%	8.3%	12.4%	8.7%	9.5%	10.2%	10.2%	11.5%	15.6%
17	UIL Holdings	$ 26.34	$ 1.73	6.6%	3.0%	4.4%	4.2%	4.2%	4.0%	3.3%	9.6%	11.0%	10.8%	10.8%	10.6%	9.9%
18	Westar Energy	$ 19.64	$ 1.22	6.2%	4.5%	3.3%	3.0%	4.5%	3.1%	8.8%	10.7%	9.5%	9.2%	10.7%	9.3%	15.0%
19	Wisconsin Energy	$ 43.95	$ 1.50	3.4%	8.0%	8.7%	9.0%	9.0%	6.4%	10.3%	11.4%	12.1%	12.4%	12.4%	9.8%	13.7%
20	Xcel Energy, Inc.	$ 19.25	$ 1.00	5.2%	6.5%	6.9%	6.8%	5.5%	4.9%	3.4%	11.7%	12.1%	12.0%	10.7%	10.1%	8.6%
	Average (h)										10.1%	10.6%	10.4%	11.1%	10.8%	12.4%

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Nov. 6, 2009).
(b) The Value Line Investment Survey (Aug. 28, Sep. 25, & Nov. 6, 2009).
(c) *Thomson ReutersCompany Report* (Oct. 20, 2009).
(d) *First Call Earnings Valuation Report* (Oct. 21, 2009).
(e) www.zacks.com (retrieved Oct. 21, 2009).
(f) See Exhibit WEA-3.
(g) Sum of dividend yield and respective growth rate.
(h) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2012-14 Market Price			2012-14 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	Allegheny Energy	70.00	45.00	$57.50	$3.40	$1.20	$26.30	64.7%	12.9%
2	ALLETE	45.00	35.00	$40.00	$2.75	$1.92	$28.75	30.2%	9.6%
3	Alliant Energy	50.00	35.00	$42.50	$3.20	$1.92	$31.05	40.0%	10.3%
4	Ameren Corp.	45.00	30.00	$37.50	$3.00	$1.70	$37.25	43.3%	8.1%
5	American Elec Pwr	50.00	35.00	$42.50	$3.50	$1.90	$33.50	45.7%	10.4%
6	Edison International	60.00	40.00	$50.00	$4.50	$1.50	$39.75	66.7%	11.3%
7	FirstEnergy Corp.	80.00	60.00	$70.00	$5.25	$2.65	$36.75	49.5%	14.3%
8	OGE Energy Corp.	45.00	35.00	$40.00	$3.25	$1.65	$27.75	49.2%	11.7%
9	Otter Tail Corp.	35.00	25.00	$30.00	$1.90	$1.30	$22.50	31.6%	8.4%
10	PG&E Corp.	55.00	40.00	$47.50	$4.25	$2.20	$35.75	48.2%	11.9%
11	Portland General Elec.	30.00	20.00	$25.00	$2.00	$1.20	$23.75	40.0%	8.4%
12	PPL Corp.	55.00	35.00	$45.00	$3.75	$1.90	$19.75	49.3%	19.0%
13	Progress Energy	50.00	35.00	$42.50	$3.60	$2.56	$36.80	28.9%	9.8%
14	P S Enterprise Group	55.00	35.00	$45.00	$3.75	$1.70	$24.25	54.7%	15.5%
15	SCANA Corp.	55.00	40.00	$47.50	$3.50	$2.10	$33.25	40.0%	10.5%
16	Sempra Energy	95.00	70.00	$82.50	$6.00	$2.10	$51.25	65.0%	11.7%
17	UIL Holdings	35.00	25.00	$30.00	$2.25	$1.73	$21.75	23.1%	10.3%
18	Westar Energy	30.00	25.00	$27.50	$2.20	$1.40	$27.20	36.4%	8.1%
19	Wisconsin Energy	75.00	55.00	$65.00	$4.50	$2.15	$38.00	52.2%	11.8%
20	Xcel Energy, Inc.	25.00	19.00	$22.00	$2.00	$1.10	$19.00	45.0%	10.5%

UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
			2008			2012-14			Adjusted "r"	
	Company	BVPS	No. Shares	Common Equity	BVPS	No. Shares	Common Equity	Chg in Equity	Adj. Factor	Adj. r
1	Allegheny Energy	$16.83	169.36	$2,850	$26.30	175.00	$4,603	10.1%	1.0479	13.5%
2	ALLETE	$25.37	32.60	$827	$28.75	41.00	$1,179	7.3%	1.0354	9.9%
3	Alliant Energy	$25.56	110.45	$2,823	$31.05	116.00	$3,602	5.0%	1.0244	10.6%
4	Ameren Corp.	$32.80	212.30	$6,963	$37.25	252.00	$9,387	6.2%	1.0299	8.3%
5	American Elec Pwr	$26.33	406.07	$10,692	$33.50	490.00	$16,415	9.0%	1.0428	10.9%
6	Edison International	$29.21	325.81	$9,517	$39.75	325.81	$12,951	6.4%	1.0308	11.7%
7	FirstEnergy Corp.	$27.17	304.84	$8,283	$36.75	304.84	$11,203	6.2%	1.0302	14.7%
8	OGE Energy Corp.	$20.29	93.50	$1,897	$27.75	103.00	$2,858	8.5%	1.0410	12.2%
9	Otter Tail Corp.	$19.14	35.38	$677	$22.50	40.00	$900	5.9%	1.0284	8.7%
10	PG&E Corp.	$25.97	361.06	$9,377	$35.75	400.00	$14,300	8.8%	1.0422	12.4%
11	Portland General Elec.	$21.64	62.58	$1,354	$23.75	80.00	$1,900	7.0%	1.0338	8.7%
12	PPL Corp.	$13.55	374.58	$5,076	$19.75	370.00	$7,308	7.6%	1.0364	19.7%
13	Progress Energy	$32.55	264.00	$8,593	$36.80	288.00	$10,598	4.3%	1.0210	10.0%
14	P S Enterprise Group	$15.36	506.02	$7,772	$24.25	490.00	$11,883	8.9%	1.0424	16.1%
15	SCANA Corp.	$25.81	118.00	$3,046	$33.25	141.00	$4,688	9.0%	1.0431	11.0%
16	Sempra Energy	$32.75	243.32	$7,969	$51.25	250.00	$12,813	10.0%	1.0475	12.3%
17	UIL Holdings	$18.85	25.17	$474	$21.75	30.80	$670	7.1%	1.0345	10.7%
18	Westar Energy	$20.18	108.31	$2,186	$27.20	114.00	$3,101	7.2%	1.0350	8.4%
19	Wisconsin Energy	$28.54	116.92	$3,337	$38.00	117.00	$4,446	5.9%	1.0287	12.2%
20	Xcel Energy, Inc.	$15.35	453.79	$6,966	$19.00	464.00	$8,816	4.8%	1.0236	10.8%

UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2008	2012-14	Change	Ratio	s	v	sv	br + sv
1	Allegheny Energy	169.4	175.0	0.66%	2.19	0.0144	0.5426	0.78%	9.5%
2	ALLETE	32.6	41.0	4.69%	1.39	0.0653	0.2813	1.84%	4.8%
3	Alliant Energy	110.5	116.0	0.99%	1.37	0.0135	0.2694	0.36%	4.6%
4	Ameren Corp.	212.3	252.0	3.49%	1.01	0.0351	0.0067	0.02%	3.6%
5	American Elec Pwr	406.1	490.0	3.83%	1.27	0.0486	0.2118	1.03%	6.0%
6	Edison International	325.8	325.8	0.00%	1.26	-	0.2050	0.00%	7.8%
7	FirstEnergy Corp.	304.8	304.8	0.00%	1.90	-	0.4750	0.00%	7.3%
8	OGE Energy Corp.	93.5	103.0	1.95%	1.44	0.0282	0.3063	0.86%	6.9%
9	Otter Tail Corp.	35.4	40.0	2.49%	1.33	0.0331	0.2500	0.83%	3.6%
10	PG&E Corp.	361.1	400.0	2.07%	1.33	0.0275	0.2474	0.68%	6.7%
11	Portland General Elec.	62.6	80.0	5.03%	1.05	0.0530	0.0500	0.26%	3.7%
12	PPL Corp.	374.6	370.0	-0.25%	2.28	(0.0056)	0.5611	-0.31%	9.4%
13	Progress Energy	264.0	288.0	1.76%	1.15	0.0203	0.1341	0.27%	3.2%
14	P S Enterprise Group	506.0	490.0	-0.64%	1.86	(0.0119)	0.4611	-0.55%	8.3%
15	SCANA Corp.	118.0	141.0	3.63%	1.43	0.0518	0.3000	1.55%	5.9%
16	Sempra Energy	243.3	250.0	0.54%	1.61	0.0087	0.3788	0.33%	8.3%
17	UIL Holdings	25.2	30.8	4.12%	1.38	0.0568	0.2750	1.56%	4.0%
18	Westar Energy	108.3	114.0	1.03%	1.01	0.0104	0.0109	0.01%	3.1%
19	Wisconsin Energy	116.9	117.0	0.01%	1.71	0.0002	0.4154	0.01%	6.4%
20	Xcel Energy, Inc.	453.8	464.0	0.45%	1.16	0.0052	0.1364	0.07%	4.9%

(a) The Value Line Investment Survey (Aug. 7, Aug. 28, & Sep. 25, 2009).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2012-14 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2012-14 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

DCF MODEL

NON-UTILITY PROXY GROUP

		Dividend Yield	Growth Rates						Cost of Equity Estimates					
		(a)	(a)	(b)	(c)	(d)	(e)	(a)	(f)	(f)	(f)	(f)	(f)	(f)
	Company	Yield	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
1	3M Company	2.87%	3.0%	9.5%	10.7%	9.4%	16.8%	8.5%	5.9%	12.4%	13.6%	12.3%	19.7%	11.4%
2	Abbott Labs.	3.64%	10.0%	11.4%	12.0%	11.2%	12.4%	18.7%	13.6%	15.0%	15.6%	14.8%	16.1%	22.3%
3	Alberto-Culver	1.22%	6.5%	11.7%	12.0%	12.5%	8.0%	13.7%	7.7%	12.9%	13.2%	13.7%	9.2%	14.9%
4	Allergan, Inc.	0.37%	13.5%	13.3%	14.0%	15.0%	18.8%	20.9%	13.9%	13.7%	14.4%	15.4%	19.1%	21.3%
5	Automatic Data Proc.	3.49%	9.0%	11.4%	11.0%	11.6%	9.8%	19.6%	12.5%	14.9%	14.5%	15.1%	13.3%	23.1%
6	Bard (C.R.)	0.84%	12.5%	14.1%	14.0%	14.1%	13.5%	17.5%	13.3%	14.9%	14.8%	14.9%	14.3%	18.4%
7	Baxter Int'l Inc.	2.06%	14.0%	12.8%	12.0%	12.5%	14.9%	17.5%	16.1%	14.9%	14.1%	14.6%	16.9%	19.5%
8	Becton, Dickinson	1.91%	10.5%	11.5%	12.0%	11.6%	13.1%	15.0%	12.4%	13.4%	13.9%	13.5%	15.0%	17.0%
9	Bemis Co.	3.47%	4.0%	8.0%	7.0%	8.0%	6.7%	12.1%	7.5%	11.5%	10.5%	11.5%	10.1%	15.6%
10	Bristol-Myers Squibb	5.70%	9.0%	9.0%	8.9%	7.0%	5.5%	15.5%	14.7%	14.7%	14.6%	12.7%	11.2%	21.2%
11	Brown-Forman 'B'	2.54%	5.0%	8.5%	8.5%	NA	11.2%	9.9%	7.5%	11.0%	11.0%	NA	13.8%	12.4%
12	Cardinal Health	2.72%	-7.0%	10.0%	10.0%	10.8%	4.9%	7.1%	-4.3%	12.7%	12.7%	13.5%	7.6%	9.8%
13	Chevron Corp.	3.98%	5.0%	5.4%	7.0%	7.7%	17.5%	16.2%	9.0%	9.4%	11.0%	11.7%	21.4%	20.2%
14	Chubb Corp.	2.87%	0.5%	8.5%	9.0%	7.0%	5.9%	17.2%	3.4%	11.4%	11.9%	9.9%	8.8%	20.1%
15	Coca-Cola	3.47%	5.5%	6.7%	8.1%	8.9%	11.4%	11.4%	9.0%	10.2%	11.6%	12.4%	14.9%	14.9%
16	Colgate-Palmolive	2.53%	11.5%	9.8%	10.5%	10.3%	19.5%	16.0%	14.0%	12.3%	13.0%	12.8%	22.0%	18.6%
17	ConAgra Foods	3.80%	11.5%	8.0%	8.0%	8.0%	6.0%	16.3%	15.3%	11.8%	11.8%	11.8%	9.8%	20.1%
18	Costco Wholesale	1.31%	5.5%	11.6%	12.0%	11.3%	8.3%	10.4%	6.8%	12.9%	13.3%	12.6%	9.6%	11.7%
19	CVS Caremark Corp.	0.82%	11.0%	12.8%	13.5%	13.4%	7.9%	24.7%	11.8%	13.6%	14.3%	14.2%	8.7%	25.5%
20	Disney (Walt)	1.38%	12.0%	7.1%	5.0%	9.2%	9.6%	22.4%	13.4%	8.5%	6.4%	10.6%	11.0%	23.8%
21	Du Pont	5.25%	1.0%	3.0%	6.0%	6.0%	5.5%	23.0%	6.3%	8.3%	11.3%	11.3%	10.8%	28.2%
22	Eaton Corp.	3.73%	-3.5%	7.3%	8.0%	9.3%	7.3%	16.4%	0.2%	11.0%	11.7%	13.0%	11.0%	20.1%
23	Ecolab Inc.	1.43%	11.5%	12.6%	13.0%	13.1%	22.9%	9.3%	12.9%	14.0%	14.4%	14.5%	24.3%	10.8%
24	Emerson Electric	3.59%	3.0%	10.1%	10.0%	10.6%	6.6%	13.4%	6.6%	13.7%	13.6%	14.2%	10.2%	17.0%
25	Everest Re Group Ltd.	2.28%	5.0%	8.3%	10.0%	10.0%	10.7%	18.0%	7.3%	10.6%	12.3%	12.3%	13.0%	20.3%
26	Exxon Mobil Corp.	2.48%	3.5%	4.5%	7.0%	8.0%	15.0%	13.2%	6.0%	7.0%	9.5%	10.5%	17.5%	15.7%
27	Gen'l Dynamics	2.64%	10.5%	8.2%	9.0%	9.7%	12.6%	22.3%	13.1%	10.8%	11.6%	12.3%	15.3%	24.9%
28	Gen'l Mills	3.24%	8.5%	8.1%	8.1%	7.8%	6.1%	11.4%	11.7%	11.3%	11.3%	11.0%	9.3%	14.6%
29	Grainger (W.W.)	2.18%	6.5%	10.9%	12.0%	10.4%	5.2%	11.4%	8.7%	13.1%	14.2%	12.6%	7.4%	13.6%
30	Heinz (H.J.)	4.53%	6.5%	7.0%	7.0%	8.5%	14.8%	13.8%	11.0%	11.5%	11.5%	13.0%	19.3%	18.3%
31	Hewlett-Packard	0.72%	9.0%	9.7%	10.5%	13.3%	9.4%	16.8%	9.7%	10.4%	11.2%	14.0%	10.1%	17.5%
32	Home Depot	3.35%	1.5%	10.5%	10.0%	10.7%	9.9%	15.0%	4.9%	13.9%	13.4%	14.1%	13.2%	18.3%
33	Hormel Foods	2.15%	10.5%	10.0%	10.0%	8.5%	10.1%	17.8%	12.7%	12.2%	12.2%	10.7%	12.3%	19.9%
34	Illinois Tool Works	3.02%	2.0%	6.0%	10.0%	7.8%	8.6%	16.0%	5.0%	9.0%	13.0%	10.8%	11.6%	19.0%
35	Int'l Business Mach.	1.89%	10.5%	9.1%	10.0%	13.6%	10.8%	17.2%	12.4%	11.0%	11.9%	15.5%	12.7%	19.1%
36	Intel Corp.	2.88%	10.0%	10.0%	10.0%	10.7%	15.1%	20.9%	12.9%	12.9%	12.9%	13.6%	17.9%	23.8%
37	ITT Corp.	1.68%	7.0%	6.7%	5.0%	10.5%	13.4%	17.5%	8.7%	8.4%	6.7%	12.2%	15.1%	19.2%

DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(c)	(d)	(e)	(a)	(f)	(f)	(f)	(f)	(f)	(f)
		Dividend	Growth Rates						Cost of Equity Estimates					
	Company	Yield	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
38	Johnson & Johnson	3.33%	7.0%	8.1%	8.0%	8.0%	8.6%	13.7%	10.3%	11.4%	11.3%	11.3%	11.9%	17.0%
39	Kellogg	3.20%	8.5%	9.8%	9.0%	8.8%	20.1%	13.0%	11.7%	13.0%	12.2%	12.0%	23.3%	16.2%
40	Kimberly-Clark	4.14%	6.0%	9.2%	9.2%	8.4%	20.8%	14.4%	10.1%	13.3%	13.3%	12.5%	24.9%	18.5%
41	Kraft Foods	4.25%	6.5%	8.5%	7.0%	11.4%	4.7%	13.0%	10.8%	12.8%	11.3%	15.7%	9.0%	17.3%
42	Lilly (Eli)	6.13%	5.0%	2.8%	2.8%	2.6%	16.4%	21.3%	11.1%	8.9%	8.9%	8.7%	22.5%	27.4%
43	Lockheed Martin	3.17%	11.0%	10.9%	10.0%	11.2%	16.7%	22.2%	14.2%	14.1%	13.2%	14.4%	19.9%	25.4%
44	McCormick & Co.	3.12%	8.0%	NA	9.0%	NA	12.4%	13.9%	11.1%	NA	12.1%	NA	15.6%	17.0%
45	McDonald's Corp.	3.94%	9.0%	9.1%	9.0%	11.7%	5.1%	10.8%	12.9%	13.0%	12.9%	15.6%	9.0%	14.7%
46	McKesson Corp.	0.87%	8.5%	11.3%	13.0%	12.3%	12.1%	9.2%	9.4%	12.2%	13.9%	13.2%	13.0%	10.1%
47	Medtronic, Inc.	2.21%	10.0%	10.2%	10.0%	10.3%	9.8%	25.3%	12.2%	12.4%	12.2%	12.5%	12.0%	27.5%
48	Microsoft Corp.	2.16%	10.0%	10.2%	10.0%	10.6%	2.5%	19.7%	12.2%	12.4%	12.2%	12.8%	4.6%	21.9%
49	NIKE, Inc. 'B'	1.97%	9.5%	12.1%	12.0%	11.6%	11.1%	15.0%	11.5%	14.1%	14.0%	13.6%	13.1%	17.0%
50	Northrop Grumman	3.65%	9.5%	12.3%	10.0%	10.1%	9.5%	24.9%	13.2%	16.0%	13.7%	13.8%	13.2%	28.5%
51	Oracle Corp.	0.93%	11.5%	13.4%	10.0%	12.0%	9.3%	18.9%	12.4%	14.3%	10.9%	12.9%	10.3%	19.8%
52	PepsiCo, Inc.	3.18%	8.0%	10.5%	10.5%	12.3%	13.2%	15.4%	11.2%	13.7%	13.7%	15.5%	16.4%	18.6%
53	Pfizer, Inc.	3.98%	-4.0%	-0.3%	0.4%	-1.5%	5.9%	3.1%	0.0%	3.7%	4.4%	2.5%	9.9%	7.1%
54	PPG Inds.	3.92%	4.0%	3.0%	3.0%	7.5%	10.0%	6.2%	7.9%	6.9%	6.9%	11.4%	13.9%	10.1%
55	Procter & Gamble	3.33%	7.5%	9.5%	10.0%	9.6%	8.5%	17.1%	10.8%	12.8%	13.3%	12.9%	11.8%	20.4%
56	Raytheon Co.	2.79%	12.0%	11.0%	10.0%	10.2%	9.5%	20.6%	14.8%	13.8%	12.8%	13.0%	12.2%	23.3%
57	Sigma-Aldrich	1.16%	7.5%	9.2%	10.0%	8.8%	15.2%	7.2%	8.7%	10.4%	11.2%	10.0%	16.4%	8.3%
58	Stryker Corp.	1.04%	12.0%	12.5%	13.0%	13.3%	13.5%	27.5%	13.0%	13.5%	14.0%	14.3%	14.5%	28.5%
59	Sysco Corp.	3.77%	8.0%	12.0%	12.0%	9.2%	6.8%	19.9%	11.8%	15.8%	15.8%	13.0%	10.5%	23.6%
60	TJX Companies	1.34%	10.5%	12.1%	12.0%	12.2%	15.6%	7.0%	11.8%	13.4%	13.3%	13.5%	16.9%	8.3%
61	United Parcel Serv.	3.41%	2.5%	7.7%	11.5%	11.4%	14.6%	15.0%	5.9%	11.1%	14.9%	14.8%	18.0%	18.4%
62	United Technologies	2.58%	7.5%	7.3%	8.0%	7.9%	14.8%	19.4%	10.1%	9.9%	10.6%	10.5%	17.3%	22.0%
63	Verizon Communic.	6.09%	4.0%	5.0%	5.0%	5.5%	5.9%	16.8%	10.1%	11.1%	11.1%	11.6%	12.0%	22.9%
64	Wal-Mart Stores	2.18%	8.5%	11.9%	11.0%	10.9%	11.3%	14.8%	10.7%	14.1%	13.2%	13.1%	13.5%	17.0%
65	Walgreen Co.	1.64%	8.5%	13.2%	14.5%	13.5%	11.6%	20.9%	10.1%	14.8%	16.1%	15.1%	13.3%	22.6%
66	Waste Management	4.03%	5.5%	11.0%	11.0%	11.0%	6.6%	9.1%	9.5%	15.0%	15.0%	15.0%	10.7%	13.1%
67	Wyeth	2.57%	2.5%	2.8%	2.6%	3.8%	14.1%	7.4%	5.1%	5.4%	5.2%	6.4%	16.7%	10.0%
	Average (g)								11.4%	12.4%	12.8%	13.0%	12.3%	12.4%

(a) www.valueline.com (retrieved Sep. 9, 2009).
(b) Thomson Reuters, *Company in Context Report* (Sep. 8, 2009).
(c) *First Call Earnings Valuation Report* (Sep. 9, 2009).
(d) www.zacks.com (retrieved Sep. 9, 2009).
(e) See Exhibit WEA-5.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2012-14 Market Price			2012-14 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	3M Company	$110.00	$90.00	$100.00	$6.25	$2.20	$23.45	64.8%	26.7%
2	Abbott Labs.	$100.00	$80.00	$90.00	$5.00	$2.18	$21.95	56.4%	22.8%
3	Alberto-Culver	$45.00	$35.00	$40.00	$2.00	$0.45	$16.30	77.5%	12.3%
4	Allergan, Inc.	$110.00	$90.00	$100.00	$4.25	$0.25	$24.20	94.1%	17.6%
5	Automatic Data Proc.	$85.00	$70.00	$77.50	$3.30	$1.60	$20.75	51.5%	15.9%
6	Bard (C.R.)	$155.00	$125.00	$140.00	$7.60	$0.94	$39.10	87.9%	19.9%
7	Baxter Int'l Inc.	$115.00	$95.00	$105.00	$6.20	$1.70	$18.80	72.6%	33.0%
8	Becton, Dickinson	$125.00	$105.00	$115.00	$7.15	$1.95	$39.20	72.7%	18.2%
9	Bemis Co.	$40.00	$35.00	$37.50	$2.20	$1.04	$18.10	52.7%	12.2%
10	Bristol-Myers Squibb	$40.00	$30.00	$35.00	$1.95	$1.40	$10.25	28.2%	19.0%
11	Brown-Forman 'B'	$70.00	$55.00	$62.50	$3.70	$1.24	$20.35	66.5%	18.2%
12	Cardinal Health	$50.00	$40.00	$45.00	$2.25	$1.00	$23.85	55.6%	9.4%
13	Chevron Corp.	$140.00	$110.00	$125.00	$12.50	$3.00	$53.15	76.0%	23.5%
14	Chubb Corp.	$85.00	$70.00	$77.50	$6.00	$2.80	$54.35	53.3%	11.0%
15	Coca-Cola	$85.00	$70.00	$77.50	$3.70	$2.00	$16.45	45.9%	22.5%
16	Colgate-Palmolive	$140.00	$115.00	$127.50	$6.30	$2.50	$17.70	60.3%	35.6%
17	ConAgra Foods	$40.00	$30.00	$35.00	$2.25	$0.86	$14.80	61.8%	15.2%
18	Costco Wholesale	$80.00	$65.00	$72.50	$3.60	$0.80	$27.35	77.8%	13.2%
19	CVS Caremark Corp.	$80.00	$65.00	$72.50	$3.70	$0.48	$36.65	87.0%	10.1%
20	Disney (Walt)	$65.00	$50.00	$57.50	$3.85	$0.60	$27.05	84.4%	14.2%
21	Du Pont	$60.00	$50.00	$55.00	$3.10	$1.92	$13.55	38.1%	22.9%
22	Eaton Corp.	$95.00	$75.00	$85.00	$5.30	$2.50	$42.35	52.8%	12.5%
23	Ecolab Inc.	$65.00	$55.00	$60.00	$3.15	$0.85	$12.25	73.0%	25.7%
24	Emerson Electric	$60.00	$50.00	$55.00	$3.20	$1.55	$12.60	51.6%	25.4%
25	Everest Re Group Ltd.	$165.00	$135.00	$150.00	$15.00	$2.35	$116.65	84.3%	12.9%
26	Exxon Mobil Corp.	$125.00	$100.00	$112.50	$9.35	$1.85	$37.30	80.2%	25.1%
27	Gen'l Dynamics	$145.00	$120.00	$132.50	$9.35	$2.50	$50.00	73.3%	18.7%
28	Gen'l Mills	$100.00	$80.00	$90.00	$5.25	$2.35	$22.00	55.2%	23.9%
29	Grainger (W.W.)	$140.00	$115.00	$127.50	$7.40	$3.00	$39.55	59.5%	18.7%
30	Heinz (H.J.)	$70.00	$55.00	$62.50	$3.80	$2.20	$9.45	42.1%	40.2%
31	Hewlett-Packard	$80.00	$65.00	$72.50	$4.50	$0.45	$26.10	90.0%	17.2%
32	Home Depot	$45.00	$35.00	$40.00	$2.50	$1.05	$14.85	58.0%	16.8%
33	Hormel Foods	$75.00	$60.00	$67.50	$3.80	$1.20	$23.85	68.4%	15.9%
34	Illinois Tool Works	$65.00	$70.00	$67.50	$3.50	$1.36	$18.55	61.1%	18.9%
35	Int'l Business Mach.	$220.00	$180.00	$200.00	$13.25	$3.00	$20.30	77.4%	65.3%
36	Intel Corp.	$40.00	$30.00	$35.00	$1.75	$0.80	$9.15	54.3%	19.1%
37	ITT Corp.	$90.00	$75.00	$82.50	$5.25	$1.24	$33.25	76.4%	15.8%
38	Johnson & Johnson	$110.00	$90.00	$100.00	$6.20	$2.50	$26.00	59.7%	23.8%
39	Kellogg	$85.00	$70.00	$77.50	$4.55	$1.75	$12.65	61.5%	36.0%
40	Kimberly-Clark	$95.00	$80.00	$87.50	$5.75	$2.55	$15.15	55.7%	38.0%
41	Kraft Foods	$50.00	$40.00	$45.00	$2.75	$1.40	$26.20	49.1%	10.5%
42	Lilly (Eli)	$80.00	$65.00	$72.50	$4.75	$2.30	$17.40	51.6%	27.3%
43	Lockheed Martin	$205.00	$170.00	$187.50	$12.50	$3.50	$42.85	72.0%	29.2%
44	McCormick & Co.	$60.00	$50.00	$55.00	$3.05	$1.28	$17.60	58.0%	17.3%
45	McDonald's Corp.	$95.00	$75.00	$85.00	$4.95	$2.85	$18.25	42.4%	27.1%
46	McKesson Corp.	$85.00	$70.00	$77.50	$5.80	$0.48	$42.65	91.7%	13.6%
47	Medtronic, Inc.	$100.00	$80.00	$90.00	$4.75	$1.20	$21.90	74.7%	21.7%
48	Microsoft Corp.	$50.00	$45.00	$47.50	$2.65	$0.80	$7.70	69.8%	34.4%
49	NIKE, Inc. 'B'	$100.00	$85.00	$92.50	$5.10	$1.50	$24.20	70.6%	21.1%
50	Northrop Grumman	$130.00	$105.00	$117.50	$8.50	$2.25	$57.15	73.5%	14.9%
51	Oracle Corp.	$45.00	$40.00	$42.50	$2.15	$0.30	$6.60	86.0%	32.6%
52	PepsiCo, Inc.	$110.00	$90.00	$100.00	$5.00	$2.10	$19.75	58.0%	25.3%
53	Pfizer, Inc.	$18.00	$15.00	$16.50	$1.40	$0.64	$13.45	54.3%	10.4%
54	PPG Inds.	$80.00	$65.00	$72.50	$5.35	$2.28	$31.45	57.4%	17.0%
55	Procter & Gamble	$105.00	$85.00	$95.00	$4.75	$1.95	$26.00	58.9%	18.3%
56	Raytheon Co.	$105.00	$85.00	$95.00	$6.45	$1.75	$44.30	72.9%	14.6%
57	Sigma-Aldrich	$70.00	$60.00	$65.00	$3.60	$0.70	$18.95	80.6%	19.0%
58	Stryker Corp.	$120.00	$90.00	$105.00	$4.75	$0.70	$27.90	85.3%	17.0%
59	Sysco Corp.	$50.00	$45.00	$47.50	$2.50	$1.30	$7.75	48.0%	32.3%
60	TJX Companies	$50.00	$45.00	$47.50	$3.40	$0.70	$10.00	79.4%	34.0%
61	United Parcel Serv.	$105.00	$85.00	$95.00	$4.40	$2.30	$9.30	47.7%	47.3%
62	United Technologies	$115.00	$95.00	$105.00	$6.60	$2.20	$26.10	66.7%	25.3%
63	Verizon Communic.	$60.00	$50.00	$55.00	$3.10	$1.96	$18.85	36.8%	16.4%
64	Wal-Mart Stores	$95.00	$75.00	$85.00	$5.20	$1.50	$28.40	71.2%	18.3%
65	Walgreen Co.	$70.00	$60.00	$65.00	$3.25	$0.64	$23.05	80.3%	14.1%
66	Waste Management	$45.00	$40.00	$42.50	$2.80	$1.50	$15.70	46.4%	17.8%
67	Wyeth	$65.00	$55.00	$60.00	$4.05	$1.45	$19.05	64.2%	21.3%

NON-UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
			2008			2012-14			Adjusted "r"	
			No.	Common		No.	Common	Chg in	Adj.	Adj.
	Company	BVPS	Shares	Equity	BVPS	Shares	Equity	Equity	Factor	r
1	3M Company	$14.24	693.54	$9,876	$23.45	680.00	$15,946	10.1%	1.0479	27.9%
2	Abbott Labs.	$11.48	1549.90	$17,793	$21.95	1520.00	$33,364	13.4%	1.0628	24.2%
3	Alberto-Culver	$11.35	97.86	$1,111	$16.30	92.00	$1,500	6.2%	1.0300	12.6%
4	Allergan, Inc.	$13.19	304.09	$4,011	$24.20	310.00	$7,502	13.3%	1.0625	18.7%
5	Automatic Data Proc.	$9.97	510.30	$5,088	$20.75	520.00	$10,790	16.2%	1.0750	17.1%
6	Bard (C.R.)	$19.89	99.39	$1,977	$39.10	90.00	$3,519	12.2%	1.0576	21.1%
7	Baxter Int'l Inc.	$10.11	615.99	$6,228	$18.80	550.00	$10,340	10.7%	1.0507	34.6%
8	Becton, Dickinson	$20.30	243.08	$4,935	$39.20	237.00	$9,290	13.5%	1.0632	19.4%
9	Bemis Co.	$13.50	99.71	$1,346	$18.10	100.00	$1,810	6.1%	1.0296	12.5%
10	Bristol-Myers Squibb	$6.20	1974.30	$12,241	$10.25	1970.00	$20,193	10.5%	1.0500	20.0%
11	Brown-Forman 'B'	$12.10	150.13	$1,817	$20.35	145.00	$2,951	10.2%	1.0485	19.1%
12	Cardinal Health	$21.70	357.10	$7,749	$23.85	350.00	$8,348	1.5%	1.0074	9.5%
13	Chevron Corp.	$43.23	2004.20	$86,642	$53.15	1950.00	$103,643	3.6%	1.0179	23.9%
14	Chubb Corp.	$38.13	352.30	$13,433	$54.35	345.00	$18,751	6.9%	1.0333	11.4%
15	Coca-Cola	$8.85	2312.00	$20,461	$16.45	2325.00	$38,246	13.3%	1.0625	23.9%
16	Colgate-Palmolive	$3.47	501.41	$1,740	$17.70	480.00	$8,496	37.3%	1.1573	41.2%
17	ConAgra Foods	$11.02	484.37	$5,338	$14.80	425.00	$6,290	3.3%	1.0164	15.5%
18	Costco Wholesale	$21.25	432.51	$9,191	$27.35	405.00	$11,077	3.8%	1.0187	13.4%
19	CVS Caremark Corp.	$23.90	1438.80	$34,387	$36.65	1350.00	$49,478	7.5%	1.0364	10.5%
20	Disney (Walt)	$17.73	1822.90	$32,320	$27.05	1610.00	$43,551	6.1%	1.0298	14.7%
21	Du Pont	$7.63	902.37	$6,885	$13.55	850.00	$11,518	10.8%	1.0514	24.1%
22	Eaton Corp.	$38.28	165.00	$6,316	$42.35	170.00	$7,200	2.7%	1.0131	12.7%
23	Ecolab Inc.	$6.65	236.20	$1,571	$12.25	245.00	$3,001	13.8%	1.0647	27.4%
24	Emerson Electric	$11.82	771.22	$9,116	$12.60	700.00	$8,820	-0.7%	0.9967	25.3%
25	Everest Re Group Ltd.	$75.62	65.60	$4,961	$116.65	60.00	$6,999	7.1%	1.0344	13.3%
26	Exxon Mobil Corp.	$22.70	4976.00	$112,955	$37.30	4300.00	$160,390	7.3%	1.0350	25.9%
27	Gen'l Dynamics	$26.00	386.71	$10,054	$50.00	365.00	$18,250	12.7%	1.0595	19.8%
28	Gen'l Mills	$18.42	337.50	$6,217	$22.00	300.00	$6,600	1.2%	1.0060	24.0%
29	Grainger (W.W.)	$27.20	74.78	$2,034	$39.55	65.00	$2,571	4.8%	1.0234	19.1%
30	Heinz (H.J.)	$3.87	315.04	$1,219	$9.45	305.00	$2,882	18.8%	1.0858	43.7%
31	Hewlett-Packard	$16.13	2415.00	$38,954	$26.10	2000.00	$52,200	6.0%	1.0293	17.7%
32	Home Depot	$10.48	1696.00	$17,774	$14.85	1685.00	$25,022	7.1%	1.0342	17.4%
33	Hormel Foods	$14.92	134.52	$2,007	$23.85	130.00	$3,101	9.1%	1.0435	16.6%
34	Illinois Tool Works	$14.41	499.12	$7,192	$18.55	470.00	$8,719	3.9%	1.0192	19.2%
35	Int'l Business Mach.	$10.06	1339.10	$13,471	$20.30	1050.00	$21,315	9.6%	1.0459	68.3%
36	Intel Corp.	$7.03	5562.00	$39,101	$9.15	6000.00	$54,900	7.0%	1.0339	19.8%
37	ITT Corp.	$16.83	181.80	$3,060	$33.25	185.00	$6,151	15.0%	1.0697	16.9%
38	Johnson & Johnson	$15.35	2769.20	$42,507	$26.00	2480.00	$64,480	8.7%	1.0416	24.8%
39	Kellogg	$3.79	381.86	$1,447	$12.65	365.00	$4,617	26.1%	1.1155	40.1%
40	Kimberly-Clark	$9.38	420.90	$3,948	$15.15	415.00	$6,287	9.8%	1.0465	39.7%
41	Kraft Foods	$15.11	1469.30	$22,201	$26.20	1400.00	$36,680	10.6%	1.0502	11.0%
42	Lilly (Eli)	$5.93	1136.10	$6,737	$17.40	1150.00	$20,010	24.3%	1.1084	30.3%
43	Lockheed Martin	$7.29	393.00	$2,865	$42.85	350.00	$14,998	39.2%	1.1640	34.0%
44	McCormick & Co.	$8.11	130.10	$1,055	$17.60	135.00	$2,376	17.6%	1.0810	18.7%
45	McDonald's Corp.	$12.00	1115.30	$13,384	$18.25	1015.00	$18,524	6.7%	1.0325	28.0%
46	McKesson Corp.	$22.85	271.00	$6,192	$42.65	254.00	$10,833	11.8%	1.0559	14.4%
47	Medtronic, Inc.	$11.42	1124.90	$12,846	$21.90	1000.00	$21,900	11.3%	1.0533	22.8%
48	Microsoft Corp.	$3.97	9380.00	$37,239	$7.70	7500.00	$57,750	9.2%	1.0438	35.9%
49	NIKE, Inc. 'B'	$15.93	491.10	$7,823	$24.20	455.00	$11,011	7.1%	1.0342	21.8%
50	Northrop Grumman	$36.45	327.01	$11,920	$57.15	300.00	$17,145	7.5%	1.0363	15.4%
51	Oracle Corp.	$4.47	5150.00	$23,021	$6.60	4300.00	$28,380	4.3%	1.0209	33.3%
52	PepsiCo, Inc.	$7.77	1553.00	$12,067	$19.75	1500.00	$29,625	19.7%	1.0896	27.6%
53	Pfizer, Inc.	$8.52	6746.00	$57,476	$13.45	6700.00	$90,115	9.4%	1.0449	10.9%
54	PPG Inds.	$20.30	164.20	$3,333	$31.45	163.00	$5,126	9.0%	1.0430	17.7%
55	Procter & Gamble	$22.46	3032.70	$68,114	$26.00	2900.00	$75,400	2.1%	1.0102	18.5%
56	Raytheon Co.	$22.71	400.10	$9,086	$44.30	370.00	$16,391	12.5%	1.0589	15.4%
57	Sigma-Aldrich	$11.29	122.13	$1,379	$18.95	120.00	$2,274	10.5%	1.0500	19.9%
58	Stryker Corp.	$13.64	396.40	$5,407	$27.90	382.00	$10,658	14.5%	1.0678	18.2%
59	Sysco Corp.	$5.67	601.23	$3,409	$7.75	550.00	$4,263	4.6%	1.0223	33.0%
60	TJX Companies	$5.17	427.95	$2,213	$10.00	360.00	$3,600	10.2%	1.0486	35.7%
61	United Parcel Serv.	$6.81	995.44	$6,779	$9.30	950.00	$8,835	5.4%	1.0265	48.6%
62	United Technologies	$16.89	942.29	$15,915	$26.10	900.00	$23,490	8.1%	1.0389	26.3%
63	Verizon Communic.	$14.68	2840.60	$41,700	$18.85	2820.00	$53,157	5.0%	1.0243	16.8%
64	Wal-Mart Stores	$16.63	3925.00	$65,273	$28.40	3700.00	$105,080	10.0%	1.0476	19.2%
65	Walgreen Co.	$13.01	989.18	$12,869	$23.05	980.00	$22,589	11.9%	1.0562	14.9%
66	Waste Management	$12.03	490.74	$5,904	$15.70	465.00	$7,301	4.3%	1.0212	18.2%
67	Wyeth	$14.40	1331.60	$19,175	$19.05	1333.50	$25,403	5.8%	1.0281	21.9%

NON-UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2008	2012-14	Change	Ratio	s	v	sv	br + sv
1	3M Company	693.54	680.00	-0.39%	4.26	(0.0168)	0.7655	-1.28%	16.8%
2	Abbott Labs.	1549.90	1520.00	-0.39%	4.10	(0.0159)	0.7561	-1.21%	12.4%
3	Alberto-Culver	97.86	92.00	-1.23%	2.45	(0.0301)	0.5925	-1.78%	8.0%
4	Allergan, Inc.	304.09	310.00	0.39%	4.13	0.0159	0.7580	1.21%	18.8%
5	Automatic Data Proc.	510.30	520.00	0.38%	3.73	0.0141	0.7323	1.03%	9.8%
6	Bard (C.R.)	99.39	90.00	-1.97%	3.58	(0.0704)	0.7207	-5.07%	13.5%
7	Baxter Int'l Inc.	615.99	550.00	-2.24%	5.59	(0.1251)	0.8210	-10.27%	14.9%
8	Becton, Dickinson	243.08	237.00	-0.51%	2.93	(0.0148)	0.6591	-0.98%	13.1%
9	Bemis Co.	99.71	100.00	0.06%	2.07	0.0012	0.5173	0.06%	6.7%
10	Bristol-Myers Squibb	1974.30	1970.00	-0.04%	3.41	(0.0015)	0.7071	-0.11%	5.5%
11	Brown-Forman 'B'	150.13	145.00	-0.69%	3.07	(0.0213)	0.6744	-1.44%	11.2%
12	Cardinal Health	357.10	350.00	-0.40%	1.89	(0.0076)	0.4700	-0.36%	4.9%
13	Chevron Corp.	2004.20	1950.00	-0.55%	2.35	(0.0129)	0.5748	-0.74%	17.5%
14	Chubb Corp.	352.30	345.00	-0.42%	1.43	(0.0060)	0.2987	-0.18%	5.9%
15	Coca-Cola	2312.00	2325.00	0.11%	4.71	0.0053	0.7877	0.42%	11.4%
16	Colgate-Palmolive	501.41	480.00	-0.87%	7.20	(0.0626)	0.8612	-5.39%	19.5%
17	ConAgra Foods	484.37	425.00	-2.58%	2.36	(0.0610)	0.5771	-3.52%	6.0%
18	Costco Wholesale	432.51	405.00	-1.31%	2.65	(0.0346)	0.6228	-2.16%	8.3%
19	CVS Caremark Corp.	1438.80	1350.00	-1.27%	1.98	(0.0250)	0.4945	-1.24%	7.9%
20	Disney (Walt)	1822.90	1610.00	-2.45%	2.13	(0.0521)	0.5296	-2.76%	9.6%
21	Du Pont	902.37	850.00	-1.19%	4.06	(0.0482)	0.7536	-3.64%	5.5%
22	Eaton Corp.	165.00	170.00	0.60%	2.01	0.0120	0.5018	0.60%	7.3%
23	Ecolab Inc.	236.20	245.00	0.73%	4.90	0.0360	0.7958	2.86%	22.9%
24	Emerson Electric	771.22	700.00	-1.92%	4.37	(0.0838)	0.7709	-6.46%	6.6%
25	Everest Re Group Ltd.	65.60	60.00	-1.77%	1.29	(0.0227)	0.2223	-0.51%	10.7%
26	Exxon Mobil Corp.	4976.00	4300.00	-2.88%	3.02	(0.0868)	0.6684	-5.80%	15.0%
27	Gen'l Dynamics	386.71	365.00	-1.15%	2.65	(0.0304)	0.6226	-1.90%	12.6%
28	Gen'l Mills	337.50	300.00	-2.33%	4.09	(0.0952)	0.7556	-7.20%	6.1%
29	Grainger (W.W.)	74.78	65.00	-2.76%	3.22	(0.0891)	0.6898	-6.15%	5.2%
30	Heinz (H.J.)	315.04	305.00	-0.65%	6.61	(0.0427)	0.8488	-3.62%	14.8%
31	Hewlett-Packard	2415.00	2000.00	-3.70%	2.78	(0.1028)	0.6400	-6.58%	9.4%
32	Home Depot	1696.00	1685.00	-0.13%	2.69	(0.0035)	0.6288	-0.22%	9.9%
33	Hormel Foods	134.52	130.00	-0.68%	2.83	(0.0193)	0.6467	-1.25%	10.1%
34	Illinois Tool Works	499.12	470.00	-1.20%	3.64	(0.0435)	0.7252	-3.15%	8.6%
35	Int'l Business Mach.	1339.10	1050.00	-4.75%	9.85	(0.4678)	0.8985	-42.03%	10.8%
36	Intel Corp.	5562.00	6000.00	1.53%	3.83	0.0584	0.7386	4.32%	15.1%
37	ITT Corp.	181.80	185.00	0.35%	2.48	0.0087	0.5970	0.52%	13.4%
38	Johnson & Johnson	2769.20	2480.00	-2.18%	3.85	(0.0839)	0.7400	-6.21%	8.6%
39	Kellogg	381.86	365.00	-0.90%	6.13	(0.0551)	0.8368	-4.61%	20.1%
40	Kimberly-Clark	420.90	415.00	-0.28%	5.78	(0.0163)	0.8269	-1.35%	20.8%
41	Kraft Foods	1469.30	1400.00	-0.96%	1.72	(0.0165)	0.4178	-0.69%	4.7%
42	Lilly (Eli)	1136.10	1150.00	0.24%	4.17	0.0101	0.7600	0.77%	16.4%
43	Lockheed Martin	393.00	350.00	-2.29%	4.38	(0.1002)	0.7715	-7.73%	16.7%
44	McCormick & Co.	130.10	135.00	0.74%	3.13	0.0232	0.6800	1.58%	12.4%
45	McDonald's Corp.	1115.30	1015.00	-1.87%	4.66	(0.0870)	0.7853	-6.83%	5.1%
46	McKesson Corp.	271.00	254.00	-1.29%	1.82	(0.0234)	0.4497	-1.05%	12.1%
47	Medtronic, Inc.	1124.90	1000.00	-2.33%	4.11	(0.0956)	0.7567	-7.23%	9.8%
48	Microsoft Corp.	9380.00	7500.00	-4.37%	6.17	(0.2699)	0.8379	-22.61%	2.5%
49	NIKE, Inc. 'B'	491.10	455.00	-1.52%	3.82	(0.0579)	0.7384	-4.28%	11.1%
50	Northrop Grumman	327.01	300.00	-1.71%	2.06	(0.0351)	0.5136	-1.81%	9.5%
51	Oracle Corp.	5150.00	4300.00	-3.54%	6.44	(0.2282)	0.8447	-19.27%	9.3%
52	PepsiCo, Inc.	1553.00	1500.00	-0.69%	5.06	(0.0350)	0.8025	-2.81%	13.2%
53	Pfizer, Inc.	6746.00	6700.00	-0.14%	1.23	(0.0017)	0.1848	-0.03%	5.9%
54	PPG Inds.	164.20	163.00	-0.15%	2.31	(0.0034)	0.5662	-0.19%	10.0%
55	Procter & Gamble	3032.70	2900.00	-0.89%	3.65	(0.0326)	0.7263	-2.36%	8.5%
56	Raytheon Co.	400.10	370.00	-1.55%	2.14	(0.0333)	0.5337	-1.78%	9.5%
57	Sigma-Aldrich	122.13	120.00	-0.35%	3.43	(0.0120)	0.7085	-0.85%	15.2%
58	Stryker Corp.	396.40	382.00	-0.74%	3.76	(0.0277)	0.7343	-2.04%	13.5%
59	Sysco Corp.	601.23	550.00	-1.77%	6.13	(0.1082)	0.8368	-9.05%	6.8%
60	TJX Companies	427.95	360.00	-3.40%	4.75	(0.1614)	0.7895	-12.75%	15.6%
61	United Parcel Serv.	995.44	950.00	-0.93%	10.22	(0.0950)	0.9021	-8.57%	14.6%
62	United Technologies	942.29	900.00	-0.91%	4.02	(0.0368)	0.7514	-2.76%	14.8%
63	Verizon Communic.	2840.60	2820.00	-0.15%	2.92	(0.0042)	0.6573	-0.28%	5.9%
64	Wal-Mart Stores	3925.00	3700.00	-1.17%	2.99	(0.0351)	0.6659	-2.34%	11.3%
65	Walgreen Co.	989.18	980.00	-0.19%	2.82	(0.0053)	0.6454	-0.34%	11.6%
66	Waste Management	490.74	465.00	-1.07%	2.71	(0.0290)	0.6306	-1.83%	6.6%
67	Wyeth	1331.60	1333.50	0.03%	3.15	0.0009	0.6825	0.06%	14.1%

(a) www.valueline.com (retrieved Sep. 9, 2009).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2012-14 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2012-14 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

CAPITAL ASSET PRICING MODEL

UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.7%	
Growth Rate (b)	9.2%	
Market Return (c)		11.9%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.2%
Market Risk Premium (e)		7.7%
Utility Proxy Group Beta (f)		0.74
Utility Proxy Group Risk Premium (g)		5.7%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.2%
Implied Cost of Equity (h)		9.9%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Oct. 1, 2009).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 based on data from *Thomson Reuters Company Report* (Oct. 1, 2009).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for October 2009 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Aug. 28, Sep. 25, & Nov. 6, 2009).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.7%	
Growth Rate (b)	9.2%	
Market Return (c)		11.9%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.2%
Market Risk Premium (e)		7.7%
Non-Utility Proxy Group Beta (f)		0.79
Utility Proxy Group Risk Premium (g)		6.1%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.2%
Implied Cost of Equity (h)		**10.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Oct. 1, 2009).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 based on data from *Thomson Reuters Company Report* (Oct. 1, 2009).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for October 2009 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved Sep. 9, 2009).
(g) (e) x (f).
(h) (d) + (g).

EXPECTED EARNINGS APPROACH

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Allegheny Energy	13.0%	1.0479	13.6%
2	ALLETE	9.0%	1.0354	9.3%
3	Alliant Energy	10.5%	1.0244	10.8%
4	Ameren Corp.	8.0%	1.0299	8.2%
5	American Elec Pwr	11.0%	1.0428	11.5%
6	Edison International	11.5%	1.0308	11.9%
7	FirstEnergy Corp.	14.5%	1.0302	14.9%
8	OGE Energy Corp.	11.5%	1.0410	12.0%
9	Otter Tail Corp.	8.5%	1.0284	8.7%
10	PG&E Corp.	12.0%	1.0422	12.5%
11	Portland General Elec.	8.5%	1.0338	8.8%
12	PPL Corp.	19.5%	1.0364	$\boxed{20.2\%}$
13	Progress Energy	9.5%	1.0210	9.7%
14	P S Enterprise Group	16.0%	1.0424	16.7%
15	SCANA Corp.	10.5%	1.0431	11.0%
16	Sempra Energy	12.0%	1.0475	12.6%
17	UIL Holdings	10.5%	1.0345	10.9%
18	Westar Energy	8.0%	1.0350	8.3%
19	Wisconsin Energy	12.0%	1.0287	12.3%
20	Xcel Energy, Inc.	10.5%	1.0236	10.7%
	Average (d)			11.3%

(a) 3-5 year projections from The Value Line Investment Survey (Aug. 28, Sep. 25, & Nov. 6, 2009).
(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit WEA-3.
(c) (a) x (b).
(d) Excludes highlighted figures.

CAPITAL STRUCTURE

UTILITY PROXY GROUP

		At Fiscal Year-End 2008 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	Allegheny Energy	59.6%	0.0%	40.4%	50.5%	0.0%	49.5%
2	ALLETE	41.7%	0.0%	58.3%	48.5%	0.0%	51.5%
3	Alliant Energy	38.0%	4.9%	57.0%	35.5%	4.0%	60.5%
4	Ameren Corp.	49.1%	1.4%	49.5%	44.5%	1.5%	54.0%
5	American Elec Pwr	59.8%	0.2%	40.0%	52.0%	0.0%	48.0%
6	Edison International	51.0%	4.2%	44.9%	50.5%	3.5%	46.0%
7	FirstEnergy Corp.	58.3%	0.0%	41.7%	51.5%	0.0%	48.5%
8	OGE Energy Corp.	53.3%	0.0%	46.7%	53.5%	0.0%	46.5%
9	Otter Tail Corp.	33.1%	1.5%	65.4%	31.0%	1.0%	68.0%
10	PG&E Corp.	50.7%	1.3%	48.0%	45.0%	1.0%	54.0%
11	Portland General Elec.	49.1%	0.0%	50.9%	50.0%	0.0%	50.0%
12	PPL Corp.	51.8%	8.8%	39.4%	52.0%	2.0%	46.0%
13	Progress Energy	54.8%	0.5%	44.7%	52.5%	0.0%	47.5%
14	P S Enterprise Group	49.4%	0.5%	50.1%	42.5%	0.0%	57.5%
15	SCANA Corp.	58.8%	1.5%	39.7%	55.5%	1.5%	43.0%
16	Sempra Energy	45.3%	1.2%	53.5%	42.0%	1.0%	57.0%
17	UIL Holdings	56.0%	0.0%	44.0%	52.0%	0.0%	48.0%
18	Westar Energy	51.4%	0.5%	48.1%	47.5%	0.0%	52.5%
19	Wisconsin Energy	55.1%	0.4%	44.5%	54.5%	0.0%	45.5%
20	Xcel Energy, Inc.	54.0%	0.7%	45.3%	51.0%	0.5%	48.5%
	Average	**51.0%**	**1.4%**	**47.6%**	**48.1%**	**0.8%**	**51.1%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Aug. 28, Sep. 25, & Nov. 6, 2009).

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY
OF
DENNIS W. BETHEL

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
DENNIS W. BETHEL ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

DIRECT TESTIMONY
OF
DENNIS W. BETHEL
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Dennis W. Bethel. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am the Managing Director – Regulated Tariffs 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 (KPCo or the Company).

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. As Managing Director- Regulated Tariffs, I direct a staff that is responsible for cost of service studies, rate design, agreements and tariffs for retail and regulated wholesale services throughout the eleven-state AEP service area. I represent AEP in Regional Transmission Organization (RTO) forums, particularly relating to the transmission tariffs, rate design, and related committee matters in the Southwest Power Pool (SPP) and the PJM Interconnection, L.L.C. (PJM).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 1973, I earned a Bachelor of Science Degree in Electrical Engineering from the University of Evansville (Indiana). I began my career with AEP, at Indiana Michigan Power Company (I&M), that same year, as a commercial and industrial customer service engineer. In 1977 I transferred to I&M's rate department. In 1980 I transferred to AEPSC, where I have held positions in Rate Research and Design, System Transactions, Transmission Operations, and Regulated Tariffs. At I&M I worked directly with customers on new and expanded service, was responsible for retail and wholesale contract development and administration, cost of service studies, rate design, fuel clause adjustments and other regulatory analyses. In the AEPSC Rate Research and Design Division, from 1980 to 1988, I performed and supervised cost of service and rate design studies and testified in a number of retail rate cases on those topics for several of the AEP East Companies. In 1988 I transferred to the System Transactions Department where I was responsible for power, interconnection and transmission-related agreements and tariffs and in 1991 was promoted to Manager – Interconnection Agreements. During this time I helped to develop and support AEP's first Open Access Transmission Tariff (OATT) filed in Docket No. ER93-540-000. In 1997 I moved to the Transmission Operations Department as Manager – Transmission Contracts and Regulatory Support, a position that was functionally separated from the merchant operations function. In June 2000, I was named Director – Transmission and Interconnection Services in the AEPSC Regulatory Services

Department. In that position I was responsible for the development and implementation of transmission, interconnection and related agreements, tariffs and policies on behalf of the AEP companies in the three regions where we provide service, SPP, PJM and the Electric Reliability Council of Texas (ERCOT). I assumed my present position in July 2005.

Q. DO YOU HOLD ANY PROFESSIONAL LICENSES?

A. Yes, I am registered as a Professional Engineer in the States of Indiana and Ohio.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I have provided expert testimony on various electric cost-of-service and rate design issues before the utility regulatory commissions of Michigan, Kentucky, Ohio, Tennessee, Virginia, and West Virginia.

I have also previously submitted testimony or affidavits on transmission and related services before the Federal Energy Regulatory Commission (FERC) in Dockets ER93-540, ER98-2786, EL02-111, et al, EL01-73, EL05-74, EL05-121, EL07-101, and ER05-751, the AEP East Companies last rate case for transmission service under the PJM OATT. In FERC Dockets ER07-1069 and ER08-1329, I sponsored AEP's transmission cost-of-service formula rates and protocols for inclusion in, respectively, the SPP OATT, on behalf of Public Service Company of Oklahoma and Southwestern Electric Power Company (SPP Companies), and in the PJM OATT, on behalf of the AEP East

Companies[1]. In FERC Docket No. ER09-1279 I sponsor changes to the AEP Transmission Agreement, a transmission cost sharing arrangement among the AEP East Operating Companies. Most recently, I have filed testimony in Docket No. ER10-355, in support of transmission cost-of-service formula rates for new transmission-only subsidiaries of AEP Transmission Company, L.L.C., that plan to build and own transmission facilities within the footprints of the AEP East Companies' and the AEP SPP Companies.

III. PURPOSE OF TESTIMONY

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

A. My testimony describes and helps to support the current level of and future trends in transmission related costs and credits billed to AEP by PJM for transmission, PJM administrative and related services. Witness Roush supports a new transmission adjustment tariff, Tariff T.A., designed to adjust monthly electric bills in respect of the difference between a base level of transmission-related costs included in base rates and the going level of transmission-related costs as charged by PJM. Specifically I will describe the following transmission cost components included in Tariff T.A. (TTA):

1. Network Integration Transmission Service (NITS), pursuant to PJM OATT Attachment H-14;

[1] The AEP East Companies include Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company.

2. Transmission Owner Scheduling, System Control and Dispatch Service, pursuant to PJM OATT Schedule 1A;
3. PJM RTO Administration fees and other charges, pursuant to PJM OATT Schedules 9 and 10;
4. PJM Regional Transmission Enhancement charges, pursuant to PJM OATT Schedule 12;
5. PJM Expansion Cost Recovery Charges (ECRC), pursuant to PJM OATT Schedule 13;
6. AEP RTO Start-up Cost Recovery Charges, pursuant to PJM OATT Attachment H-14; and
7. Default Allocation Assessments, and any refunds of such assessments, under Section 15.2 of the PJM Operating Agreement.

Q. WHY IS IT APPROPRIATE FOR TRANSMISSION-RELATED COSTS TO BE RECOVERED THROUGH AN ADJUSTMENT TARIFF?

A. Transmission and related services are necessary components of the power supply function, without which KPCo could not deliver power and energy to its Kentucky retail customers. The charges for transmission and related services are determined by FERC-approved rates, and they are increasing. AEPSC vigorously represents the interests of KPCo and the other AEP East Companies through participation in the various PJM Stakeholder forums, and in proceedings before the FERC. PJM budgets, policies and rate designs, however, reflect the wishes of a majority of the stakeholders, the will of the PJM Board of Directors and Management, and the decisions of the FERC. The AEP East and SPP

Companies were directed by FERC to join RTOs as a condition of the merger between AEP and the Central and Southwest Corporation (CSW). KPCo customers enjoy savings as a result of the merger. Before joining PJM, KPCo sought and obtained the Commission's approval to do so. Finally, by potentially reducing the frequency with which KPCo may need to file costly general rate proceedings, as transmission-related costs change, Tariff T. A. creates the opportunity, over time, to reduce costs for KPCo customers. Given all these circumstances, I believe that it is appropriate that KPCo be permitted to adjust its rates periodically through Tariff T.A., in order to maintain a balance between its transmission and related costs and the revenues its Kentucky retail rates collect for those services.

Q. YOU MENTIONED THAT YOU HAVE SUBMITTED TESTIMONY IN FERC DOCKET ER09-1279. HOW AND WHEN WILL THE CHANGES TO THE AEP TRANSMISSION AGREEMENT PROPOSED IN THAT CASE IMPACT KPCo'S COSTS FOR TRANSMISSION SERVICE?

A. The AEP Transmission Agreement (AEPTA), executed by the AEP East Companies in 1984, specifies a method by which the signatories ("Members") share costs related to certain transmission (Bulk Transmission) investments that they have made. The AEPTA defines Bulk Transmission investments as the original cost, net of investment tax credits, for transmission lines operated at 138 kV or higher, and transmission stations that contain extra-high voltage facilities. In Docket No. ER09-1279, the AEP East Companies have proposed to make changes to the transmission costs that are shared, and to the cost sharing mechanism. As it presently stands, the AEPTA provides that Members with Bulk Transmission investments that exceed their member load ratio (MLR) share of the total of such investments by all the Members (Surplus Members) receive payments from Members that have invested less than their MLR share of the total in such facilities (Deficit Members). KPCo has been a Surplus Member under the AEPTA since its inception, and has received payments, approximately $8 million in 2009, from the Deficit Members. These receipts have benefited customers in the form of retail and wholesale rates that are lower than they otherwise would have been.

When the AEP East Companies joined PJM, a new AEP East Transmission cost sharing mechanism, the PJM OATT, came into play. PJM charges the AEP East Companies for transmission service over the combined transmission facilities owned by the AEP East Companies. Pursuant to the OATT transmission rate design, first approved for the AEP East Companies in FERC Docket ER93-540, the cost of all transmission facilities owned by the AEP East Companies (Rolled-In Cost), not just the Bulk Transmission investments, are shared through the OATT. Further, the formula used to determine the Rolled-In costs, including the return allowed on investments, is different than under the AEPTA.

Finally, as I mentioned earlier, in Docket No. ER09-1279, the AEP East Companies propose under the revised AEPTA to eliminate the present Bulk Transmission investment sharing mechanism, and replace it with one based on the OATT. The proposed changes to the AEPTA allocate the Rolled-in Cost reflected in the OATT using the average of the prior year monthly coincident peaks (12 CP) instead of the MLR, and specifies how they will share other PJM transmission-related charges and revenues that were not addressed by the AEPTA.

KPCo will experience a cost decrease if the changes proposed by the AEP East Companies are approved by the FERC; however, the FERC set the matter for hearing, and is holding that process in abeyance while the interested parties pursue settlement discussions. The settlement discussions are privileged, and at this stage in the process it is not possible to predict what the outcome might be. The KPSC is represented in the proceeding and is participating in the settlement discussions.

The Transmission Adjustment Tariff proposed by KPCo in this proceeding would provide a mechanism to promptly adjust retail rates for any settlement or FERC decision in that Docket.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit DWB-1, a summary of the AEP East Companies' PJM Administrative charges and average cost per MWh for the 12 months ended November 30, 2009; and
2. Exhibit DWB-2, a graphical illustration of the trend in PJM Regional Transmission Expansion Plan project spending and AEP East Company charges and projected charges from 2007 through 2014.

IV. PJM NETWORK INTEGRATION TRANSMISSION SERVICE

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH NETWORK INTEGRATION TRANSMISSION SERVICE.

A. The NITS costs are comprised of the Company's share of the FERC approved Annual Transmission Revenue Requirement (ATRR) associated with the AEP System transmission facilities in the AEP Zone of PJM. The AEP Zone ATRR is determined by a formula as specified in accordance with PJM OATT Attachment H-14A, the AEP formula rate implementation protocols and PJM OATT Attachment H-14B, the Formula Rate Template.

Q. IS AEP's FORMULA RATE IN THE PJM OATT CURRENTLY APPROVED BY FERC?

A. Yes, subject to the outcome of proceedings in FERC Docket No. ER08-1329-000.

Q. PLEASE EXPLAIN THE STATUS OF FERC DOCKET NO. ER08-1329-000.

A. In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM, and to implement a formula rate allowing annual adjustments reflecting future changes in cost of service. In September 2008, the FERC issued an order accepting AEP's proposed formula rate, subject to a compliance filing, and suspended the rate until March 1, 2009. In addition, the order established settlement proceedings with an Administrative Law Judge. Those settlement negotiations are on going. Per the FERC's order, the formula rate became effective on March 1, 2009, subject to refund, and AEP posted the first annual update for the twelve month period July 1, 2009 through

June 30, 2010. KPCo Witness Roush has applied the charges that will be billed for service beginning July 1, 2009, to estimate KPCo's cost of transmission service during the initial TTA effective period. The NITS charge effective July 1, 2009 is $69.42 per MW per day, a 4.5% increase from the initial charge under the formula rate ($66.41), and a 20% increase from the rate that had been effective prior to March 1, 2009 ($57.78). As previously mentioned, the charges are presently subject to refund, with interest at a FERC defined rate, and both the AEP formula rate and the TTA contain true-up mechanisms. As a result, the TTA transmission charges, estimated based on the AEP formula rate, will be trued-up to actual costs in due course.

Q. ARE THERE CREDITS ASSOCIATED WITH PJM POINT-TO-POINT TRANSMISSION SERVICE ON THE AEP ZONAL NETWORK INTEGRATION TRANSMISSION SERVICE BILLS?

A. Yes. Each month, PJM allocates revenues for both firm and non-firm point-to-point (PTP) transmission service to the various PJM Transmission Zones, proportionate to the revenue requirements for NITS in each zone. In addition, the NITS formula rate includes credits within the formula rate revenue requirement calculation for PTP revenues under "grandfathered" or "pre-RTO" transmission service contracts, and for transmission construction-related services that the AEP Companies provide to third parties, net of the costs to provide those services.

V. TRANSMISSION OWNER SCHEDULING, SYSTEM CONTROL & DISPATCH SERVICE (SCHEDULE 1A)

Q. PLEASE DESCRIBE THE CHARGES PURSUANT TO PJM OATT SCHEDULE 1A, TRANSMISSION OWNER SCHEDULING SYSTEM CONTROL AND DISPATCH SERVICE.

A. PJM OATT Schedule 1A contains a rate, specified in \$/MWh, for Scheduling, System Control and Dispatch (Scheduling) Service provided by PJM Transmission Owners in each PJM Zone. The AEP East Operating Companies' rate for that service is updated annually with the NITS formula rate update discussed above. Prior to March 1, 2009, the rate was \$0.0686/MWh. From March 1 through June 31, 2009 it was \$0.0555/MWh. The 2009 Annual Update resulted in an increase to \$0.0711/MWh effective July 1, 2009. Witness Roush has used the July 1, 2009 rate to estimate KPCo's Schedule 1A costs going forward under the TTA. The rate includes the AEP Companies' costs to provide system control and dispatch service at the zonal level.

VI. PJM RTO ADMINISTRATION FEES

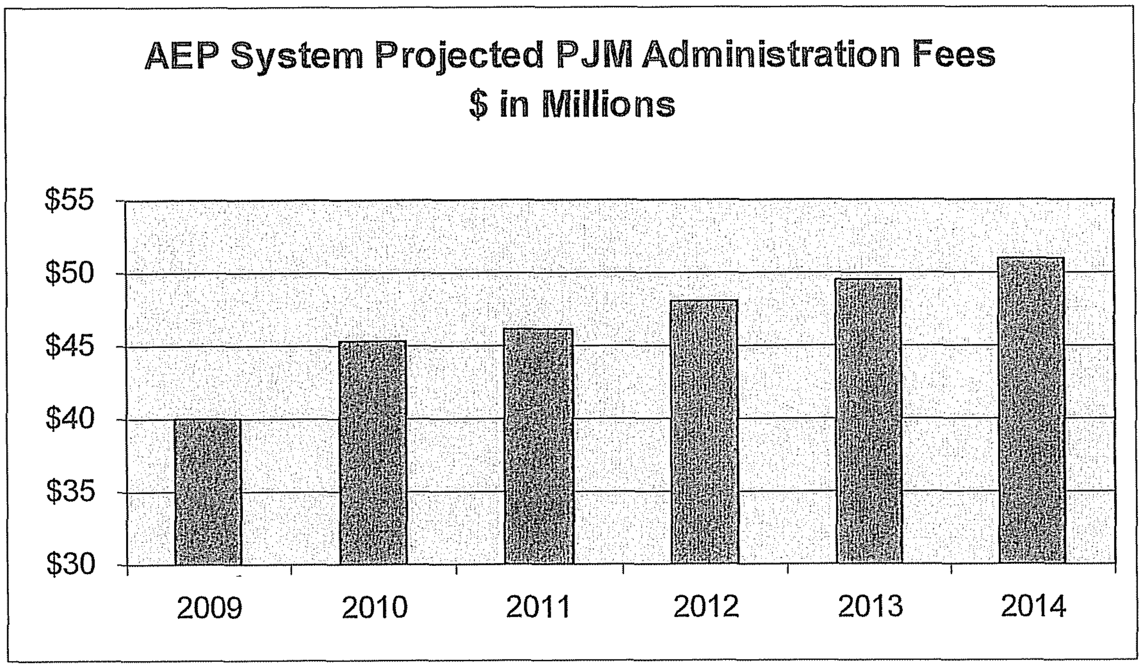
Q. WHAT ARE THE TYPES OF PJM ADMINISTRATION AND RELATED FEES THAT ARE INCLUDED IN THE TTA?

A. PJM charges each market participant on a monthly basis a number of administration fees to recover its operating costs. PJM also charges fees to transmission customers and other market participants to fund the operation of FERC and certain other organizations that are involved in management of transmission reliability and regulation. These fees are defined in the PJM OATT and are approved by the FERC. The components of these administration fees, by PJM OATT Schedule number, are:

- 9-1, Control Area Administration Service;
- 9-2, Financial Transmission Rights (FTR) Administration Service;
- 9-3, Market Support Service;
- 9-4, Regulation and Frequency Response Administration Service;
- 9-5, Capacity Resource and Obligation Management Service;
- 9-6, Formula Rate for Costs of Advanced Second Control Center;
- 9-FERC, FERC Annual Charge Recovery;
- 9-OPSI, OPSI Funding, for the Organization of PJM States, Inc. (OPSI);
- 9-FINCON, Finance Committee Retained Outside Consultant charges;
- 9-MMU, Market Monitor Unit funding charge;
- 10-NERC, North American Electric Reliability Corporation Charge; and,
- 10-RFC, ReliabilityFirst Corporation Charge.

Q. HOW ARE THE PJM ADMINISTRATION COSTS EXPECTED TO CHANGE OVER THE NEXT FEW YEARS?

A. The PJM and other RTO-related administration charges (Schedules 9 and 10) billed to the AEP East Companies for service to all their retail and wholesale customers is expected to total about $40 million during 2009. Based on preliminary PJM budget planning, AEPSC estimates that those charges will increase to about $51 million by 2014, a 26% increase over the next five years. The expected year to year change is illustrated in the following chart:



Q. WHAT IS PJM SCHEDULE 9-1, CONTROL AREA ADMINISTRATION SERVICE AND HOW IS IT BILLED?

A. Control Area Administration Service comprises all of the activities of PJM associated with preserving the reliability of the PJM Region and administering point-to-point transmission service and network integration transmission service. This service is billed to each user, including AEP, based on MWhs of energy delivered.

Q. WHAT IS PJM SCHEDULE 9-2, FTR ADMINISTRATION SERVICE AND HOW IS IT BILLED?

A. The FTR Administration Service comprises all of the activities of PJM associated with administering financial transmission rights (FTRs), including coordination of FTR bilateral trading, administration of FTR auctions, support of PJM's online internet-based eFTR tool, and FTR award analyses. FTR Administration Service is billed to each FTR market participant based on three components:

- the quantity of FTR MWhs of all FTRs held by the market participant times the PJM Tariff rate,
- the number of hours in all bids to buy FTR obligations during the annual auction and all monthly auctions, multiplied by the PJM Tariff rate, and
- five times the number of hours in all bids to buy FTR options during the annual auction and all monthly auctions, multiplied by the PJM Tariff rate.

Q. WHAT IS PJM SCHEDULE 9-3, MARKET SUPPORT SERVICE AND HOW IS IT BILLED?

A. Market Support Service comprises all of the activities of PJM associated with supporting the operation of the PJM Interchange Energy Market and related functions, including market modeling and scheduling functions, locational marginal pricing support, market settlements and billing, support of PJM's internet-based customer interactive tool known as eSchedules, and market monitoring. PJM bills each market participant a Market Support charge equal to the sum of the following components:

- MWhs of energy delivered to load in the PJM Region or for export, plus MWhs of energy input into the transmission system, plus MWhs of all accepted increment and decrement bids times the PJM Tariff rate.

- The number of bid/offer segments submitted during the period times the PJM Tariff rate. A bid/offer segment is each price/quantity pair submitted into the day-ahead energy market.

Q. WHAT IS PJM SCHEDULE 9-4, REGULATION AND FREQUENCY RESPONSE ADMINISTRATION SERVICE, AND HOW IS IT BILLED?

A. Regulation and Frequency Response Administration Service comprises all of the activities of PJM associated with administering the provision of regulation and frequency response service. Regulation and frequency response service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled frequency at sixty Hertz. PJM administration costs associated with the provision of Regulation and Frequency Response Administration Service are billed to LSEs and generators based on MWhs of regulation service.

Q. WHAT IS PJM SCHEDULE 9-5, CAPACITY RESOURCE AND OBLIGATION MANAGEMENT SERVICE, AND HOW IS IT BILLED?

A. This service comprises the activities of PJM associated with assuring that customers have arranged for sufficient generating capacity to meet their capacity obligations. This service is billed to LSEs, generators and other market participants based on the MW-days of resource or obligation provided.

Q. PLEASE EXPLAIN PJM SCHEDULE 9-6, FORMULA RATE FOR COSTS OF ADVANCED SECOND CONTROL CENTER.

A. This formula rate recovers the costs of PJM's advanced second control center, as set forth in Schedule 9-6. Monthly charges are assessed to all users of services under PJM OATT Schedules 9-1 through 9-5. The charges are based on the applicable billing determinants set forth in Schedules 9-1 through 9-5.

Q. WHAT CHARGES ARE CONTAINED IN PJM SCHEDULE 9–FERC?

A. PJM is subject to an annual charge assessed by the FERC to cover the costs of that agency. PJM bills this charge to transmission customers based on their total MWhs of electric energy delivered.

Q. PLEASE EXPLAIN THE ORGANIZATION OF PJM STATES AND ITS FUNDING, PJM SCHEDULE 9-OPSI.

A. The Organization of PJM States was established during 2005. The purpose of OPSI is to maintain an organization of electric utility regulatory agencies in the 13 states and the District of Columbia within which PJM operates. OPSI Member Regulatory Agencies' activities include, but are not limited to, coordinating activities such as data collection, issues analyses, and policy formulation related to PJM, its operations, its market monitor, and related FERC matters. The Schedule 9-OPSI charge to each transmission customer is based on the MWhs of energy delivered to load.

Q. WHAT IS THE PJM FINANCE COMMITTEE RETAINED OUTSIDE CONSULTANT CHARGE, PJM SCHEDULE 9-FINCON?

A. PJM anticipates retaining consultants to assist the PJM Finance Committee, and has created Schedule 9-FINCON to collect financial consultant costs. PJM has not yet begun to collect costs for this activity, but when PJM incurs such costs they will be recovered through the Schedule 9-FINCON charge, and thus it is appropriate now to establish a place for those costs in the TTA.

Q. WHAT IS THE PJM SCHEDULE 9-MMU FEE AND HOW IS IT BILLED?

A. In order to ensure independence and identify potential or actual market manipulation, PJM, per FERC order, receives oversight from a Market Monitor. This fee funds this market monitoring service. Schedule 9-MMU collects the Market Monitoring Unit's cost from all transmission service customers, generators and other energy market bidders based upon MWh of service provided, bid or taken.

Q. WHAT IS THE PJM SCHEDULE 10-NERC FEE AND HOW IS IT BILLED?

A. The North American Electric Reliability Corporation (NERC) develops and enforces reliability standards for the bulk power system in North America. PJM Schedule 9-FERC recovers NERC operations costs for the PJM Region. The fee is charged in all PJM zones other than the Duquesne and Dominion Zones and is assessed to LSEs and others based on MWh of energy deliveries.

Q. WHAT IS THE PJM SCHEDULE 10-RFC FEE AND HOW IS IT BILLED?

A. ReliabilityFirst Corporation (RFC) operates under the NERC umbrella; its mission being to preserve and enhance electric service reliability and security for the interconnected electric systems within the ReliabilityFirst geographic area. This area encompasses all of PJM except the Duquesne and Dominion Zones. The fee is assessed based upon MWh of load, including losses.

Q. ARE THERE ANY TRUE-UP TYPE ADJUSTMENTS OF THE PJM ADMINISTRATIVE FEES?

A. Yes. PJM uses stated rates to fund the activities covered by Schedules 9-1 through 9-5 and then computes an after-the-fact adjustment, based upon actual revenues recovered and actual costs for these services. The TTA has been designed to capture these adjustments to the PJM Administrative charges. Exhibit DWB-1 summarizes the PJM and related administrative charges billed to the AEP East Companies for their firm power customers during the twelve months ended November 30, 2009, showing the breakdown of the charges by PJM Tariff component. The summary shows that, taking into account the cost true-up adjustments, PJM charged significantly less than the maximum stated rates contained in OATT Schedules 9-1 through 9-5 during 2009. For example, the stated rate for Schedule 9-1, Control Area Services, is $0.1809 per MWh, but PJM's actual charges were 68% of the allowed level at $0.1237 per MWh. The charges under Schedules 9-2 through 9-5 vary from the maximum stated levels by similar amounts ranging from 53% to 78% of the maximum rates.

Q. HOW DO PJM'S ADMINISRATIVE COSTS COMPARE TO THOSE OF OTHER RTOS?

A. The AEP East Companies' PJM and related administrative charges averaged about $0.29 per MWh during 2009. A report published for the American Public Power Association by GDS Associates in February 2007, *Electric Market Reform Initiative (EMRI) Task 2, Analysis of Operational and Administrative Cost of RTOs* [2], indicates that PJM Administration costs were lowest in 2005 among five RTOs that operate markets as well as transmission. More recently, data filed in Michigan Public Service Commission Case No. U-15677 by The Detroit Edison

[2] http://www.appanet.org/files/PDFs/ExecutiveSummaryCostofRTOs20507GDS.pdf

Company indicates that Edison's costs for MidWest ISO administrative charges average about $0.40/MWh.

VII. PJM REGIONAL TRANSMISSION ENHANCEMENTS (SCHEDULE 12)

Q. PLEASE PROVIDE AN OVERVIEW OF THE PJM REGIONAL TRANSMISSION ENHANCEMENT PROCESS AND SCHEDULE 12 OF THE PJM OATT.

A. PJM has implemented a regional transmission planning process through which Regional Transmission Expansion Plans (RTEP) are developed annually pursuant to Schedule 6 of the PJM Operating Agreement. The transmission RTEP project costs are allocated by PJM in accordance with FERC approved allocation methods. The allocation factors are set forth in Schedule 12 of the PJM OATT. The transmission owners that build RTEP projects establish their annual revenue requirements either through a formula rate or a separate rate filing approved by FERC.

Q. PLEASE DESCRIBE THE CURRENT COST ALLOCATION PROCESS FOR RTEP PROJECTS IN PJM.

A. PJM allocates the revenue requirements for RTEP projects by one of two methods, depending on the scope of the project. PJM uses a beneficiary pays approach for new facilities that operate below 500 kV (Lower Voltage Facilities) and allocates on a region wide basis, the cost of new facilities that operate at or above 500 kV (Regional Facilities). The costs of certain lower voltage facilities necessary to support the new Regional Facilities (Necessary Lower Voltage Facilities) are also allocated on a region-wide basis. PJM designates, in

Schedule 12-Appendix, the zonal cost responsibility for Regional Facilities and other facilities allocated using the beneficiary pays method. The Regional Facilities' costs are allocated among the PJM Zones on an annual load-ratio share basis. The cost responsibility allocated to each zone for all RTEP projects is charged to NITS customers based on their respective Network Service Peak Load (NSPL) shares of the zonal load.

Q. PLEASE DISCUSS THE LEVELS OF TRANSMISSION CONSTRUCTION AND SCHEDULE 12 CHARGES BEING INCURRED BY AEP, AND THE TREND EXPECTED IN THOSE CHARGES OVER THE NEXT FEW YEARS.

A. My Exhibit DWB-2 contains two bar graphs. The first (top) graph shows the annual transmission capital expenditures that, based on PJM's approved RTEP as of 2009, I estimate the various facility builders will incur through 2014. The second (bottom) bar graph shows the annual cost I estimate PJM will bill to the AEP East Companies for those projects. These graphs show the annual capital expenditures increasing from about $700 million in 2008 to nearly $7 billion, in 2014, causing AEP's charges to increase sharply from about $4.6 million in 2008 to approximately $160 million by 2014. The estimated annual charges increase in-step with construction spending because the builders of the largest projects have received FERC approval of formula rates that include collection of a current return on construction work in progress (CWIP). The 2007 through 2009 charges are based on AEP's actual bills, while the 2010 through 2014 projections reflect the total project costs published by PJM, estimated annual construction spending, and a 15% annual carrying charge rate, which represents an estimate of the return, taxes, O&M and other costs of service.

VIII. PJM EXPANSION (ECRC) AND RTO START UP COST RECOVERY CHARGES (SCRC)

Q. WHAT COSTS ARE BEING COLLECTED THROUGH THE ECRC RATES?

A. The ECRC rates recover costs that PJM incurred to expand the RTO to accommodate the addition of the AEP East Companies and other new PJM Members in 2004 and 2005. During the expansion period, PJM charged its costs directly to the AEP East Companies, Commonwealth Edison Company (ComEd), Dayton Power and Light Company (Dayton), and Dominion Virginia Power Company (Dominion). After joining the RTO, AEP, ComEd and Dayton filed a rate proposal at the FERC requesting RTO-wide recovery of the expansion costs billed to them by PJM. Although this proposal was opposed by the prior Membership, a settlement was reached that recovers the AEP, ComEd and Dayton costs from loads in all zones of PJM, except the Dominion Zone. Dominion elected not to include its own PJM expansion funding costs in the ECRC rates, and was exempted from the ECRC charges. The ECRC rates will be collected for a ten-year period, coinciding with the FERC-approved amortization period for the PJM expansion costs.

Q. WHAT COSTS ARE BEING COLLECTED THROUGH THE SCRC RATE?

A. The SCRC rate is a charge that recovers the AEP East Companies' direct costs for RTO development and start-up. That charge is only billed to AEP and other

NITS customers in the AEP Zone. The SCRC rate collects the AEP RTO start-up costs and FERC-approved carrying costs over the fifteen-year period that the costs are being amortized.

IX. DEFAULT ALLOCATIONS ASSESSMENTS

Q. WHAT ARE THE DEFAULT ALLOCATION ASSESSMENTS?

A. Default allocation charges occur when PJM has uncollectible accounts; these amounts are allocated under Section 15.2 of the PJM operating agreement. When PJM allocates such costs to AEP, recovery of KPCo's share of those costs allocated to the Kentucky jurisdiction through the TTA is appropriate.

X. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My Direct Testimony describes the costs incurred by KPCo for Transmission and Related services obtained from the PJM RTO pursuant to the PJM OATT. The largest transmission-related expense incurred by KPCo, for Network Integration Transmission Service, changes each year pursuant to the AEP East Companies' formula rate, also approved by the FERC. PJM Administration charges and funding fees for FERC, OPSI, NERC, RFC and the PJM Market Monitoring Unit are also significant costs, which are expected to increase more than 25% over the next five years. Further, KPCo incurs charges for new transmission facilities being constructed under the PJM Regional Transmission Expansion Plan. Those costs are expected to increase by more than 1100% during the next five years (from $13.4 M in 2009 to $160 M in 2014). AEPSC represents KPCo's interests in numerous PJM stakeholder forums and markets, and verifies PJM monthly billing statements, all in an effort to ensure that KPCo and the other AEP East Companies enjoy maximum benefits from the RTO, and that all charges are as authorized by the FERC. The KPSC has approved KPCo's participation in the RTO. For all the above reasons, and as further supported in the foregoing Direct Testimony, it is my opinion that the Transmission Adjustment Tariff (Tariff T.A.) proposed by KPCo, and described by Witness Roush, is reasonable and should be approved, should the Commission agree that it has such authority.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT

Dennis W. Bethel, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Dennis W. Bethel

Dennis W. Bethel

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Dennis W. Bethel this 16th day of December 2009.

Ellen A. McGuinell

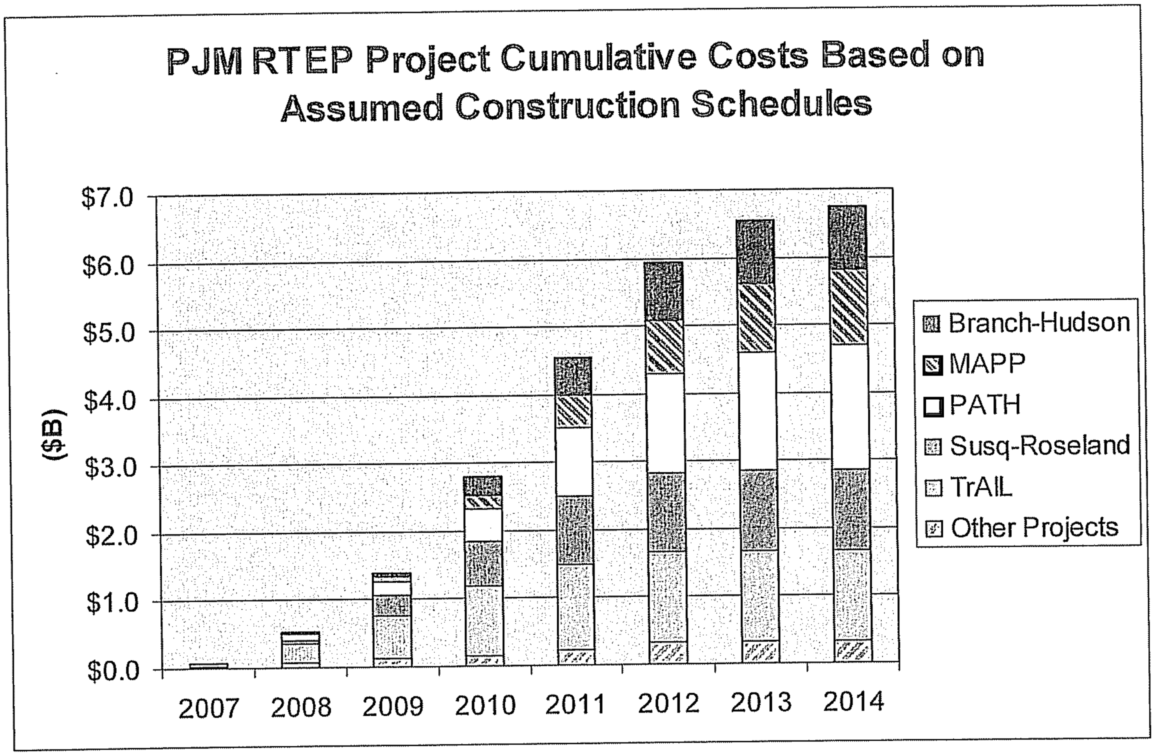
Notary Public

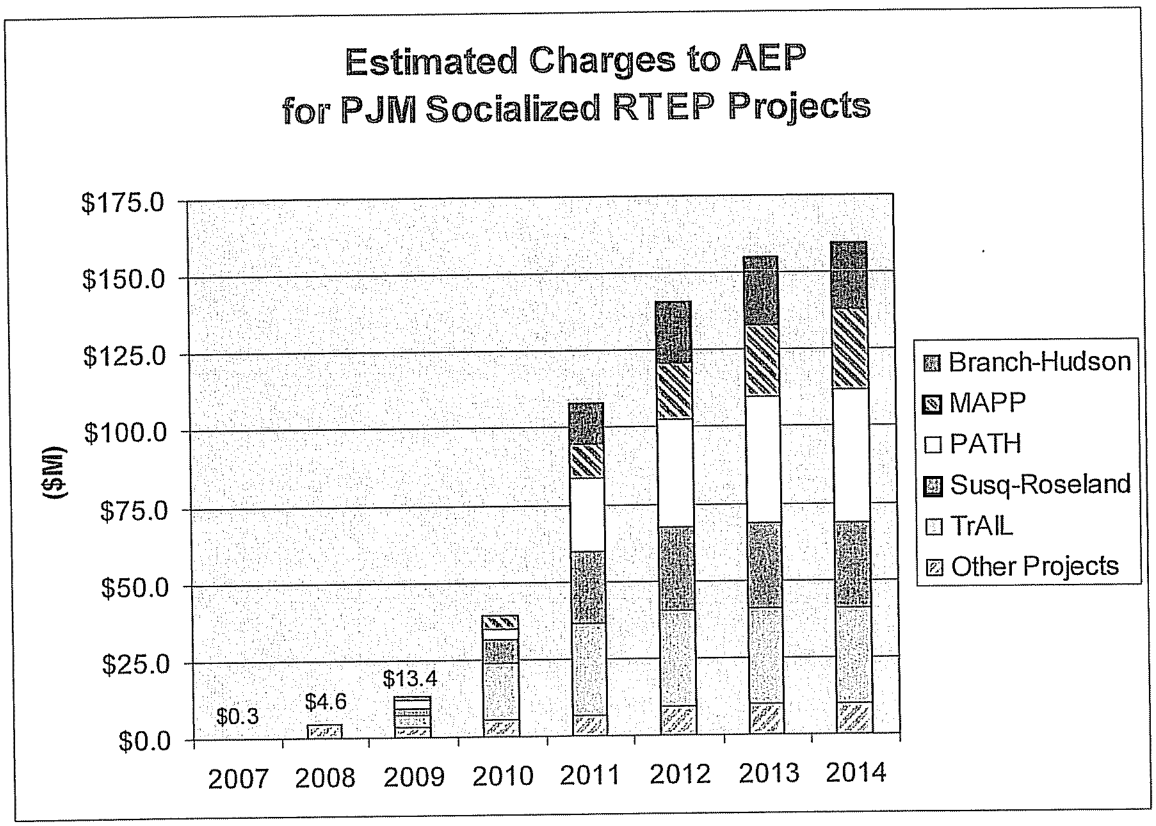
My Commission Expires May 11th, 2011

AEP Ea panies
PJM Administrative Tarif[illegible]ates and Actual Charges
Twelve Months Ended November 30, 2009

Schedule	Billing Units	Max Rate	Avg Qtr Rate	Stated or Formula	Billing Units and Charges: Billing Units	Billing Units and Charges: AEP Charges	Avg. Charges Per MWh Load	Rate Schedule
		$/Unit	$/Unit					
9-1: Control Area	MWh of energy delivered (incl. losses) for PTP and NITS	0.1809	0.1237	Stated	120,244,741	$ 14,961,190	0.1244	9-1
9-2: Financial Transmission Rights	MW of all FTRs held for each hour, summed for all hours	0.0027	0.0021	Stated	201,406,406			
9-2: Financial Transmission Rights	5x the # of hours in all bids submitted by user to buy FTR Options	0.0019	0.0010	Stated	1,558,585			
9-2: Financial Transmission Rights	# of hours in all bids submitted by user to buy FTR Obligations	0.0019	0.0010	Stated	7,860,891			
9-2: Total						$ 422,836	0.0035	9-2
9-3: Market Support	MWh of energy deliv. (losses & net behind mtr. gen.; ≥0) or exported for PTP and NITS**	0.0399	0.0264	Stated	127,478,256			
9-3: Market Support	MWh of energy input to transmission system as Generation Provider*	0.0399	0.0264	Stated	125,969,976			
9-3: Market Support	MWH of all accepted Increment, Decrement. And "up-to" congestion bids	0.0399	0.0264	Stated	8,296,132			
9-3: Market Support	Generation Offer Segments	0.0577	0.0437	Stated	234,215			
9-3: Market Support	Demand + Transaction Bid/Offer Segments	0.0577	0.0437	Stated	85,663			
9-3: Total						$ 6,999,142	0.0582	9-3
9-4: Regulation and Frequency Response	MWh of hourly regulation objective as LSE, and regulation scheduled from owned gen. units	0.2442	0.1577	Stated	1,657,370	$ 267,462	0.0022	9-4
9-5: Capacity Resource and Obligation Mgmt	MWd of Unforced Capacity Obligation, and MW share of Unforced Cap. of all Cap. incl. FRR (MWd)	0.0922	0.0653	Stated	17,329,893	$ 1,132,801	0.0094	9-5
9-6: Formula Rate for Advanced 2nd Cont. Center	Surcharge based on Charges for Schedules 9-1 through 9-5		n/a	Formula	n/a	$ 908,968	0.0076	9-6
9-FERC: FERC Annual Charge Recovery	MWh of energy delivered (incl. losses) for PTP and NITS		0.0546	Formula	120,244,741	$ 6,541,130	0.0544	9-FERC
9-OPSI: OPSI Funding	MWh of energy delivered (incl. losses) for PTP and NITS		0.0006	Formula	120,244,741	$ 74,824	0.0006	9-OPSI
9-FINCON[1]	Allocation based on (MWh transmission usage / total MWH energy deliv. PTP and NITS)		n/a	Formula	n/a	$ -	0.0000	9-FINCON
9-MMU Charge	MWh of: Energy input as Gen. Provider, Energy delivered/exported, & accepted bids		0.0053	Formula	261,744,364			
9-MMU Charge	Generation Offer Segments and Demand + Transaction Bid/Offer Segments		0.0054	Formula	319,878			
9-MMU Total						$ 1,388,970	0.0116	9-MMU
10-NERC: N. Amer. Electric Rel. Corp. Charge	MWh to be delivered (incl. losses) for PTP and NITS less MWh to be deliv. to Dominion & Duquesne		0.0067	Formula	118,944,992	$ 795,009		10-NERC
10-RFC: Reliability First Corporation Charge	MWh to be delivered (incl. losses) for PTP and NITS less MWh to be deliv. to Dominion & Duquesne		0.0088	Formula	118,944,992	$ 1,047,487		10-RFC
Total PJM and Other Admin					**120,244,741**	**$ 34,539,819**	**0.2873**	**All 9&10**

[1] Finance Committee Retained Outside Consultant
* Generation Provider as defined as: i) the Gen. Owner as noted on PJM's records ii) a Network or PTP Cust. for energy arranged to be delivered or iii) a Market Seller which arranges for power imports with no identifiable Trans. Cust.
** MWh of energy delivered to load or exported excludes MWh when the Point of Delivery and Point of Receipt are at interconnections of the PJM Region with other Control Areas


PJM RTEP Project Cumulative Costs Based on Assumed Construction Schedules
$7.0
$6.0
$5.0
$4.0
$3.0
$2.0
$1.0
$0.0
($B)
2007
2008
2009
2010
2011
2012
2013
2014
Branch-Hudson
MAPP
PATH
Susq-Roseland
TrAIL
Other Projects


Estimated Charges to AEP for PJM Socialized RTEP Projects
$175.0
$150.0
$125.0
$100.0
$75.0
$50.0
$25.0
$0.0
($M)
$0.3
$4.6
$13.4
2007
2008
2009
2010
2011
2012
2013
2014
Branch-Hudson
MAPP
PATH
Susq-Roseland
TrAIL
Other Projects

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY
OF
JAY F. GODFREY

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
JAY F. GODFREY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

DIRECT TESTIMONY OF
JAY F. GODFREY, 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 Jay F. Godfrey. I am employed as Managing Director – Renewable Energy for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power, Inc (AEP). AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including Kentucky Power Company ("Kentucky Power, KPCo or Company"). My business address is 155 West Nationwide Boulevard, Columbus, Ohio 43215.

II. Background

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I earned a Bachelor's degree in Business Administration from California State University - Chico and a Master's degree in Business Administration from National University. In 2006 I completed the AEP Strategic Leadership Program at The Ohio State University.

I have over fourteen years of commercial and financial management experience in the wind energy industry. Prior to joining AEPSC's wind energy group in 2002, I worked for seven years in various project finance and wind project development roles in Europe and the U.S. for Enron Wind Corporation, since acquired by General Electric (GE), which operates today as GE Energy. Other business management experience includes serving as the Financial Controller for two publicly held companies in non-energy related fields, and holding other management positions.

Since joining AEPSC, I have been involved in the asset management and project financing of AEP's two wind projects, the 150 MW Trent Wind Farm and the 160.5 MW Desert Sky Wind Farm, development efforts for potential green-field projects, and the procurement and management of AEP's wind and solar renewable energy purchase agreements which now total approximately 1,306 MW. My experience includes negotiating wind and solar energy power purchase and sales agreements, wind system operations and maintenance agreements, real estate agreements related to wind projects, wind turbine purchase agreements, and project loan documents. I also have experience evaluating the impact of various financial parameters on wind and solar project investment returns. I serve as a non-voting member of the Board of Directors of the American Wind Energy Association (AWEA), the Washington D.C. based trade association for the wind industry, and currently serve as chair to the AWEA Utility Working Group which advises that same Board.

Q: WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR – RENEWABLE ENERGY?

A: As Managing Director – Renewable Energy, I am responsible for managing AEP's portfolio of renewable Power Purchase Agreements (PPAs) and related long-term structured greenhouse gas / carbon credit offset agreements. I direct the team that structures and issues the renewable energy Requests for Proposals (RFPs) and model PPAs, reviews and responds to questions posed by potential bidders, and evaluates proposals. I also lead the negotiation and finalization of the PPAs with the winning bidder(s). In addition, I am responsible for the acquisition of potential new wind project development sites within AEP's service territory.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A: Yes. I have filed testimony before the Public Utility Commission of Texas, in PUC Docket Nos. 31326 and 32624; the Indiana Utility Regulatory Commission in Cause Nos. 43328 and 43750; the Michigan Public Service Commission, in Case No. U-15361; the Public Utilities Commission of Ohio, in Case No. 08-917-EL-SSO and Case No. 08-918-EL-SSO; the Corporation Commission of the State of Oklahoma in Cause No PUD 20090031; and the Virginia State Corporation Commission in Case PUE-2009-00102. I also provided testimony before the Virginia State Corporation Commission in Case No. PUE-2008-00003 and oral testimony before the Indiana State Regulatory Flexibility Committee and before the Virginia State Corporation Commission in Case PUE-2009-00038.

III. <u>Purpose of Testimony</u>

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

A. The purpose of my testimony in this proceeding is to support KPCo's request for Kentucky Public Service Commission (KPSC) approval of a Wind Power Purchase Agreement (PPA) between KPCo and FPL Energy Illinois Wind, LLC (FPLEWIC) also known the Lee-DeKalb Wind Energy Center (LDWEC) for the sale of a 100

MW[1] share of its electrical output and environmental attributes to KPCo for a 20 year period. As the name implies, the project is located primarily in Lee and DeKalb Counties, in northern Illinois. FPLEWIC is a subsidiary of NextEra Energy Resources, which is an affiliate of FPL Group, Inc. I will discuss AEP's experience with wind energy projects and technology, renewable energy in the U.S., the wind resources within the PJM Interconnect, the Request for Proposals (RFP) process which led to the execution of the Wind PPA securing the construction of a wind energy generation facility and KPCo's rights to its power production, capacity and environmental attributes, and the benefits associated with Renewable Energy Certificates (RECs).

Q: ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A: I am sponsoring Exhibit JFG-1, which is a summary of the Wind PPA terms between LDWEC, "Seller", and KPCo, "Purchaser." Exhibit JFG-2, which is the Wind PPA between KPCo and LDWEC. I am also sponsoring Exhibit JFG-3, which illustrates a comparison of the qualified bids received in response to the 2009 Renewable RFP. Each exhibit, with the exception of JFG-3, which is entirely confidential, has a public version and a version for which the Company is seeking confidential treatment pursuant to KRS 61.878 and 804 KAR 5:001, Section 8. These exhibits were prepared by me or under my direction and supervision.

IV. <u>AEP Wind Energy Projects</u>

Q: DOES AEP HAVE EXPERIENCE IN THE DEVELOPMENT, CONSTRUCTION, OWNERSHIP, AND OPERATION OF ANY WIND ENERGY PROJECTS?

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[1] A percentage share equal to 100 MW of the facility capacity, which is currently 217.5 MW.

A: Yes. AEP has been involved in the development of several wind energy projects. In fact, AEP is a pioneer in wind power research and development. In 1995, the former Central and South West Corporation (CSW), which merged with AEP in June 2000, built the first utility-scale wind farm in Texas, which is the state that now leads the nation in wind energy production. The 6 megawatt (MW) Fort Davis wind facility was the first project completed under the United States Department of Energy (DOE) and Electric Power Research Institute (EPRI) Turbine Verification Program and was developed to encourage the manufacture of wind turbines in the United States. At the time, the 500 kilowatt (kW) wind turbines were the largest U.S.-manufactured wind turbines. The project exceeded its five-year scope and the experience enabled the company to move forward with other projects, including larger scale developments using more advanced and larger wind turbines.

In 2001, AEP completed the construction of the Trent Wind Farm, also known as the Trent Mesa Wind Project. A wholly owned wind power plant, the Trent Mesa Wind Project consists of one hundred General Electric (GE) Wind Energy wind turbines rated at 1.5 MW each for a total capacity of 150 MW. AEP oversaw the construction of and owns and operates the Trent Mesa Wind Project.

AEP also owns and operates the Desert Sky Wind Farm, which was completed in December of 2001. AEP purchased the Desert Sky Wind Farm in December of 2001. The wind farm consists of one hundred seven GE Energy wind turbines rated at 1.5 MW each, for a total nameplate capacity of 160.5 MW which it owns and operates.

Q: HAS AEP ENTERED INTO ANY LONG-TERM PURCHASE AGREEMENTS FOR WIND ENERGY?

A: Yes. Not including the KPCo PPA with LDWEC, AEP has entered into fifteen long-term purchase agreements for wind energy to serve customers of its regulated electric operating companies. Currently, AEP affiliates have agreements to purchase the energy output from three wind facilities located in Illinois, three wind facilities located in Indiana, five wind facilities located in Oklahoma, one wind facility located in West Virginia, and one wind facility located Texas.

In addition to the fifteen long-term wind generation purchase agreements described above, AEP Energy Partners, a non-regulated AEP subsidiary, is an owner/operator of the facilities, are parties to two long-term wind generation sales agreements to unaffiliated utilities encompassing 100% of the output of both the Trent Mesa Wind Project and the Desert Sky Wind Farm, which are located in Texas. They additionally purchase the output under long-term contracts from two additional wind projects in Texas totaling 177 MW.

Q: WOULD YOU PLEASE SUMMARIZE THE MAGNITUDE AND NATURE OF AEP'S EXISTING WIND GENERATION RESOURCES?

A: AEP currently has 1296.1 MW of long-term renewable wind energy resources under contract, as shown in Table 1. With the addition of the 100 MW PPA project to KPCo's portfolio, all seven AEP operating companies that own generation resources will now have long-term contracts for renewable energy. Table-1, shown below, lists the existing wind PPA's for each operating company.

TABLE-1:

AEP Operating Companies' Long-Term Wind Energy Power Purchase Agreements

AEP Operating Company	Execution Date	Developer	Project	Contracted Quantity (MW)
Public Service Company of Oklahoma	2/05	Horizon Wind Energy	Blue Canyon II	151.2
Public Service Company of Oklahoma	4/05	NextEra (FPL)	Weatherford	147.0
Public Service Company of Oklahoma	8/06	Edison Mission	Sleeping Bear	94.5
Indiana Michigan Power	8/07	BP/Dominion	Fowler I	100.0
Appalachian Power Company	8/07	BP Wind Energy	Fowler III	100.0
Appalachian Power Company	9/07	Orion	Camp Grove	75.0
Appalachian Power Company	8/08	Invenergy LLC	Beech Ridge	100.5
Southwestern Electric Power Company	12/08	Babcock & Brown	Majestic	79.5
Public Service Company of Oklahoma	1/09	NextEra (FPL)	Elk City	98.9
Public Service Company of Oklahoma	2/09	Horizon Wind Energy	Blue Canyon V	99.0
Appalachian Power Company	2/09	Invenergy LLC	Grand Ridge II	51.0
Appalachian Power Company	2/09	Invenergy LLC	Grand Ridge III	49.5
Indiana Michigan Power	2/09	BP Wind Energy	Fowler II	50.0
Ohio Power Company	2/09	BP Wind Energy	Fowler II	50.0
Columbus Southern Power	2/09	BP Wind Energy	Fowler II	50.0
Total				**1296.1**

V. Wind as a Resource

Q: WHAT ARE THE KEY CHARACTERISTICS OF WIND AS AN ENERGY RESOURCE IN PJM AND THROUGHOUT THE UNITED STATES?

A: Wind is a clean, inexhaustible, indigenous energy source. Wind farms do not use any fuel for their operations, which means that there is no mining or drilling for fuel, no radioactive or hazardous wastes, and no use of water for steam or cooling. Therefore, wind power operates without emitting any greenhouse gases (GHGs) or other pollutants. The absence of fuel also means that the price of wind power does not vary in accordance with fuel prices. In fact, wind is one of the lowest-priced renewable energy technologies available today.

The use of wind as an energy resource is accompanied by a unique set of characteristics. Wind is intermittent energy resource and it does not always blow when electricity is needed. Since wind energy cannot be stored, it cannot be harnessed to meet the time of electricity demands, which gives wind relatively lower capacity values, vis-à-vis other generation resources with the same nameplate rating. In addition, geographical areas providing the best wind resources may be located in remote areas requiring the construction of transmission lines in order to connect wind farms with the power transmission grid. Wind is also limited in that it does not always blow consistently in the same geographical location at all times of the year. In some regions, the wind does not blow at all during the humid summer months when electricity is needed the most for cooling though it does generally blow more robustly during winter months where energy is also needed for heating. However, there are sites where the availability of wind resources and transmission lines meet the challenges facing wind power in other areas.

The wind resource does not appear to be an issue in relation to the LDWEC project. The primary location of the Project, northern Illinois, is generally acknowledged as having the best wind resources within the thirteen (13) states plus the District of Columbia which comprise the PJM grid.

Q: WHAT ARE THE KEY CHARACTERISTICS OF WIND AS AN ENERGY RESOURCE IN PJM?

A: Wind energy technology has experienced major advancements in the past ten years. In 1996, the average utility-scale wind turbine had a capacity of 550 kW, an average hub height of nearly 131 feet, and produced enough energy to power approximately 125 average American homes for one year. Today, the average wind turbine capacity being installed in the United States is at least 1.5 MW, with an average hub height of 265 feet, and produces enough energy to power approximately 425 average American homes for one year. Improvements in technology continue to make wind turbines more efficient. Technological improvements that have occurred in the past few years, which serve as benefits to the LDWEC project, include the following:

Wind Turbine Availability:

Availability Factor (AF) is a measurement of the reliability of a generating unit. It refers to the percentage of time that a generating unit is ready to generate and is not out of service for maintenance or repairs. Modern wind turbines can have an AF of more than 98%--higher than most other types of generating units. After more than two decades of engineering refinement, today's wind machines are highly available and reliable.

Capacity Factor:

Capacity Factor (CF) is one element in measuring the productivity of a wind turbine or any other power production unit. It compares the unit's actual energy production over a given period of time with the amount of energy the unit would have produced if it had run at its full capacity for the same period of time.

A wind plant is "fueled" by the wind, which blows steadily at times and not at all at other times. Although modern utility-scale wind turbines typically operate 65% to 90% of the time, they most often generate at less than full capacity. Therefore, a CF of 25% to 45% is common, although they may achieve higher CFs during windy time periods. By comparison, per the North American Electric Reliability Corporation (NERC), a typical base load coal unit will have a CF in the range of 70 - 80%.

Wind Turbine Design and Size:

Utility-scale wind turbines for land-based wind farms come in various sizes, with rotor diameters ranging from about 70 meters (m) to about 100 m or 230 to 310 feet, and with towers of roughly the same size. A 100 m machine, with an 80 m tower, would have a total height from the tower base to the tip of the rotor of approximately 150 m (465 feet). In recent years, the height of the towers have increased allowing wind farms to take advantage of stronger wind currents that tend to occur at a greater height, though the increase in the cost of steel has reduced the economic incentive of building wind turbine towers at the highest levels.

Identifying Wind Resources:

The power available from the wind is a function of the cube of the wind speed. Therefore, a doubling of the wind speed yields eight times the power output from the wind turbine. All other things being equal, a wind turbine at a site with an average wind speed of 5 m per second (m/s), or 11.2 miles per hour (mph), will produce nearly twice as much power as a wind turbine at a location where the wind speed averages 4 m/s, or 8.9 mph.

VI. Wind Power Purchase Agreement

Q: WOULD YOU PLEASE DESCRIBE THE WIND ENERGY GENERATION FACILITY TO BE CONSTRUCTED IN ILLINOIS?

A. The Project is developed under the direction of NextEra. The first phase of the project is for 217.5 MW and could be expanded by an additional 22.5 MW for a total of 240 MW. The Project is being developed primarily in Lee and Dekalb Counties in Illinois on approximately 22,000 contiguous acres of land that has been secured in the area. The Project was chosen for the consistent strong winds over the area and for its access to existing electrical transmission lines. Upon completion of the initial phase, the Project is expected to supply enough energy to meet the annual electric needs of approximately 49,500 average U.S. homes.

Q: WHAT EXPERIENCE DOES NEXTERA HAVE IN THE WIND GENERATION BUSINESS?

A: NextEra is the largest owner of wind generation resources in the United States with over 6,200 MW in operation spread over 17 states as of the end of 2008 according to the American Wind Energy Association. In public filings, NextEra has projected that it will add another 1,170 MW to this total in 2009 of which 217.5 MW includes the LDWEC project.

Q: WHAT ROLE DID YOU HAVE IN THE RFP PROCESS?

A: My involvement in the RFP process was to ensure that the RFP conformed with AEP's intent to competitively bid and secure up to 1,100 MW of additional renewable resources on behalf of its regulated operating companies scheduled to be operational by December 31, 2011 and from which KPCo and its affiliates would purchase energy, capacity, and environmental attributes for a term of 20 years. As with past RFPs, I directed the entire process including structuring and issuing the RFP, reviewing and responding to questions posed by potential bidders, evaluating proposals, negotiating with "short-listed" bidders, and selecting the winning proposal(s).

Q: WHY DID AEPSC ISSUE AN RFP FOR RENEWABLE ENERGY RESOURCES ON BEHALF OF ITS OPERATING COMPANIES?

A: As discussed more fully in the direct testimony of KPCo witness Weaver, KPCo's affiliate, AEPSC, issued the RFP in order to advance its strategy to voluntarily reduce, avoid, and offset GHG emissions produced by its generation fleet by diversifying its current fleet with zero emission generation technology.

As states throughout the U.S. continue to implement Renewable Portfolio Standards (RPS) and goals, the availability of renewable energy may be constrained in the coming years. For example, a majority of the states in the PJM footprint have enacted mandatory RPS, which has already resulted in increased demand for renewables. Current state mandates within PJM include: Delaware, Illinois, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Rhode Island, West Virginia, and the District of Columbia. Even if these same standards and goals spur growth in the number of renewable energy providers, there is no guarantee that the supply of renewable energy resources will remain abreast of the demand.

Acting now is also important to take advantage of industry subsidies that are being offered by the government. As stated in the testimony of Company Witness Scott Weaver, the renewable energy production tax credit (PTC), a credit of 2.1 cents per kilowatt-hour, is the primary federal incentive for wind energy and has been essential to the industry's growth. Although the PTC has undergone a series of short-term extensions since its establishment in 1992, in February of 2009, through the American Recovery and Reinvestment Act, Congress acted to provide a three-year extension of the PTC through December 31, 2012. It also provided a subsidy as an alternative to the PTC in the form of either an Investment Tax Credit

(ITC), in the amount of 30% of the facility costs, or a grant-in-lieu of the ITC for the same amount through December 31, 2010. These federal subsidies, which go to the at-risk owner of the facility, helps to buy-down the purchase price that KPCo or any purchaser would pay for the renewable energy product. In other words, the tax credit ultimately decreases the amount that native load customers pay for renewable energy products. If Congress does not extend the ITC beyond 2010 or the PTC beyond 2012, KPCo customers will end up paying more to acquire additional megawatt-hours of renewable energy as a part of any federal or state mandate. Obtaining a prudent amount of renewable energy while the PTC/ITC is in place mitigates the potential risks associated with having to acquire renewable energy in constrained markets and without the benefit of such a credit or subsidy.

Q: ARE THERE ANY OTHER ADVANTAGES TO THE TIMING OF KPCO'S WIND ENERGY ACQUISITION FROM THE LDWEC PROJECT?

A: Yes. Currently, wind energy is generally acknowledged as the most economical new source of renewable energy in the U.S. In fact, KPCo is the beneficiary of the "early mover discount" because wind is also, in general, the most economical renewable generation resource in the PJM region, as evidenced by recent RFPs that show that it is cheaper than other new renewable generation resources, including solar and hydro. The best sites offer the most reasonably-priced energy in PJM and will be built-out first, and, as stated earlier, the availability of resources will become constrained as more utilities seek to add renewables due to state and potential federal requirements, resulting in higher prices. It is to the advantage of utilities and their customers to obtain the lowest, reasonable cost wind energy to hedge against future price increases and regulatory requirements.

Q: WAS AEP'S WIND EXPERIENCE BENEFICIAL IN DEVELOPING THE RFP AND SUBSEQUENT WIND PPA?

A: AEP is able to leverage its experience as a wind generation developer, owner, operator, and seller, along with its experience conducting RFP's and negotiating long-term wind energy agreements, to effectively balance the interests of both the developer and KPCo.

Q: GENERALLY DESCRIBE THE RFP AND THE PROCESS IMPLEMENTED FOR CONDUCTING THE RFP?

A: AEPSC, as agent for KPCo and the other six operating companies issued an RFP on June 1st, 2009 attached as Exhibit JFG-1. The bids sought by the 1,100 MW Renewables RFP was for projects with a minimum 20 MW (nameplate) of new renewable generation capable of being operational by December 31, 2011 to fulfill a portion of AEP's energy and capacity requirements for KPCo. The RFP stipulated that all initial and future outputs of the facility, including energy, capacity, and environmental attributes, including RECs, be sold to KPCo through a PPA for a term of 20 years. The bidder is required to deliver its electrical output to the transmission system (a substation bus) of a PJM member. The bidder is also responsible for any feasibility or impact studies and upgrades required to the transmission system to accommodate the facility's electrical output. Bidders were required to offer "all-in" pricing, which includes all fixed and variable costs associated with capital expenditures, operation and maintenance (O&M), and any other costs associated with delivering the full output of the facility to the delivery point. Bidders were also required to provide "time-of-day" pricing that paid the Seller more for energy produced during peak demand periods (summer afternoons) and less during periods of generally low demand (spring and fall months and nights and weekends).

The RFP included a Form PPA, which defined items such as terms and conditions of service, commercial operation and construction of the facility, delivery and metering, O&M, performance assurance, insurance, permitting and licensing, Supervisory Control and Data Acquisition (SCADA) requirements, billing and settlement terms, and credit and collateral requirements. The PPA serves as the contract between the Seller (awarded bidder) and KPCo.

The RFP required bidders to document their financial and technical capabilities to ensure the successful construction of the project, and to demonstrate that they had successfully completed the development, financing, and commissioning of at least one utility scale renewable energy project in the United States with characteristics similar to the project defined in the RFP. For wind projects, AEPSC required bidders to provide a summary of the wind speed data, including meteorological source and basis, used in the development of energy projections for the project. This data was to include an 8,760 hour calendar year wind forecast for the proposed hub height. In addition, the RFP required that proposals contain an 8,760 hour calendar year energy production profile, including losses, adjusted for the proposed site's air density, fully explaining all assumptions, extrapolations, and adjustments, and disclosing the proposed wind turbine power curve.

To maximize interest and response from bidders, AEPSC conducted the 1,100 RFP on behalf of the seven AEP operating companies and conducted two pre-bid Webinars open to all interested bidders.

Proposals were to include detailed data on the proposed project location and construction schedule, including site plans, interconnection status and requirements, permitting requirements, documentation of secured land rights, financing plans, and other documentation demonstrating that the bidder has the ability and legal right to construct, interconnect, and operate the project as proposed. Site plans were to include a detailed technical description of the proposed project, including commercial operating experience of the proposed wind generator and warranty terms. Plans were also to include a detailed description of the proposed data acquisition and monitoring system to supply KPCo with real-time operational data.

AEPSC distributed the RFP announcement via direct electronic mail messages to renewable generation developers known to AEP. In addition, AEPSC issued a news release on June 1, 2009, to various renewable and energy industry publications to notify entities that may not have been included in the direct electronic mail, but may have an interest in participating in the RFP. The RFP was also announced on the DOE Energy Efficiency and Renewable Energy's "The Green Power Network" web site. The RFP was publicly posted on AEP's web site at www.aep.com/go/rfp.

Q: HOW DID AEP PROCESS AND EVALUATE THE BIDS IT RECEIVED IN RESPONSE TO THE RFP?

A: AEPSC first reviewed each proposal to determine if all of the required information was provided. AEPSC then ranked all of the conforming proposals based on pricing structure, and developed a "short list" of proposals from a total of four bidders based on both price and non-price (risk) factors. Price factors, which were weighted approximately 60%, included energy pricing and the cost to transmit and deliver energy from the delivery point to KPCo's load. Non-price factors, which were weighted approximately 40%, included the location of the project relative to KPCo's service territory, developer experience, viability of schedule, lead time to full operation, creditworthiness, financing plan, proximity to and availability of transmission, lead time of any required transmission upgrades, property and site land rights and control, feasibility of future facility expansion, nameplate capacity, wind turbine technology, analysis of wind and energy production forecasts, and nature and quantity of exceptions to the Wind PPA included in the RFP.

Based on an evaluation of price and non-price factors, AEPSC selected NextEra's Project proposal, among others, for further (post-bid) negotiations.

Q: WOULD YOU PLEASE CHARACTERIZE THE BIDS AEPSC RECEIVED IN RESPONSE TO THE RFP?

A. Yes. AEPSC received twenty-two bids from renewable energy developers for projects interconnected into PJM and located in Illinois, Pennsylvania, Indiana, West Virginia, Ohio, and Maryland. The total capacity of projects for which AEPSC received bids was approximately 2,200 MW.

Exhibit JFG-3 shows the qualified bids for PJM projects received in response to the 2009 RFP. The chart in JFG-3 reflects the prices represented in an Around the Clock (ATC) basis for bundled product (Energy + Capacity + RECs) on a $/MWh basis, adjusted for time-of-day pricing and expected production, that were bid in response to the RFP. The "bundled energy" price applies to all of the renewable contracts that were a result of these RFPs. As shown in Exhibit JFG-3, the LDWEC PPA that was executed on behalf of KPCo was amongst the lowest costs of the overall bids received in the RFP for renewables in PJM.

Q: WHAT WAS THE RESULT OF THE RFP PROCESS?

A: Based on a final analysis of all relevant factors affecting both KPCo and its customers, AEPSC selected a 100 MW portion from the 217.5 MW (nameplate) proposal from NextEra. KPCo and LDWF executed, subject to any necessary regulatory approval for cost recovery, a Wind PPA with a wind weighted average around-the-clock 2009 contract price as identified in Exhibit JFG-1. This price will escalate beginning in January 1, 2012 at 2.25% per year for the term of the contract. A summary of the terms and conditions of the Wind PPA resulting from the RFP process is attached to my testimony as Exhibit JFG-1, and the Wind PPA is attached to my testimony as Exhibit JFG-2.

The results of the RFP fulfilled KPCo's intent to secure one or more PPA(s) totaling 100 MW share of a renewable wind generation consistent with the KPCo Integrated Resource Plan which was filed August 17, 2009. The Wind PPA will supply a 100 MW share of its electrical output and environmental attributes to KPCo for a period of 20 years at a reasonable cost and terms for KPCo and its customers, effective with the approval of the cost recovery sought in this petition.

Q: WOULD YOU PLEASE EXPLAIN HOW THE TIME-OF-DAY CHARACTERISTICS OF WIND ENERGY IMPACTED THE TERMS AND CONDITIONS OF THE LDWEC WIND PPA?

A. To address the generation characteristics of wind energy, a three-tiered approach to the pricing was structured by dividing the year into Off-peak, Peak, and Premium-peak periods. The bids received in the 2009 RFP established an initial Off-peak price (energy + capacity + RECs) at a level much lower than the expected annual average around-the-clock (ATC) price was expected to be. Bidders were asked to bid a Peak and a Premium-peak price (120% of the Peak price). The Premium-peak pricing, also referred to as "Super-peak", consists of the peak weekdays that occur during the winter months (December – February) and two of the summer months (July and August). Because of this price structuring, KPCo pays substantially less Off-peak than for Peak and Super-peak. Time-of-day pricing thus better aligns the cost for renewable energy with the market value of energy.

Approximately 56% of wind generation in PJM is expected to be available during off-peak periods (nights + weekends + NERC holidays), with the balance occurring during peak periods (weekdays). By way of comparison, approximately 53% of the hours in a given year are off-peak hours.

Q: WHAT IS THE ADVANTAGE OF EXECUTING A 20-YEAR WIND PPA ON BEHALF OF KPCO?

A. The 20-year Wind PPA also provides a direct benefit to the consumer. The 20-year agreement, which is also the expected life of the technology, allows renewable energy resource providers to procure long-term financing, thereby amortizing the cost of their projects over a longer period. Such financing has the effect of reducing the upfront costs and allows for a more economically levelized price over the term of the contract.

VII. <u>Renewable Energy Certificates</u>

Q: WOULD YOU PLEASE DESCRIBE THE RECS THAT KPCO WILL OBTAIN IN CONJUNCTION WITH THE PROJECT?

A: The Wind PPA stipulates that KPCo will receive all current and future attributes from the Project, including the associated RECs. These RECs are legal proof that one megawatt-hour (MWh) of electricity has been generated by a renewable-fueled or environmentally friendly source. The RECs will be tracked through the PJM Generation Attribute Tracking System (GATS). Administered by PJM Environmental Services, Inc., GATS is a database that tracks the ownership of RECs and generation attributes that result from the generation of electricity as they are traded or used to meet government standards. GATS provides environmental and emissions attributes reporting and tracking services to its subscribers in support of RPS and other information disclosure requirements that may be implemented by government agencies. The RECs associated with the Project demonstrate that KPCo has obtained all attributes associated with the renewable energy produced by the Project.

VIII. Conclusion

Q: BASED ON YOUR FAMILIARITY WITH THE RFP PROCESS AS YOU HAVE DESCRIBED IT, AND BASED ON YOUR EXPERIENCE IN THE DEVELOPMENT AND COMMERCIAL OPERATION OF WIND GENERATION FACILITIES AND WITH WIND GENERATION AGREEMENTS AS BOTH A PURCHASER AND SELLER, DOES THE WIND PPA DESCRIBED HEREIN PRESENT A PRUDENT, VALUABLE, AND REASONABLY PRICED RENEWABLE ENERGY GENERATION RESOURCE FOR KPCO?

A: Yes, it does.

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

A: Yes, it does.

AFFIDAVIT

Jay F. Godfrey, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Jay F. Godfrey

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Jay F. Godfrey this 21st day of December 2009.

Notary Public

My Commission Expires January 4, 2014

DONNA J. STEPHENS
Notary Public, State of Ohio
My Commission Expires 01-04-2014

KENTUCKY POWER COMPANY
RENEWABLE ENERGY
PURCHASE AGREEMENT ("REPA")
WITH
FPL ENERGY ILLINOIS WIND, LLC

SUMMARY TERM SHEET

Kentucky Power Company entered into an agreement (REPA) with FPL Energy Illinois Wind for an aggregate nameplate output of 100 MW from the first 217.5 MW phase of its Lee-DeKalb Wind Energy Center being constructed in Lee and DeKalb counties, Illinois. The terms, conditions and pricing provisions of the REPA are summarized below.

This Summary Term Sheet is qualified in its entirety by reference to, and in no way alters, the actual terms and conditions of the REPA. Except as otherwise indicated by the context, capitalized terms used in this Summary Term Sheet have the meanings set forth in the REPA.

- Seller. FPL Energy Illinois Wind, LLC.

- Purchaser: Kentucky Power Company.

- Term. 20 years from the Contract Start Date ("CSD").

- Price. Purchaser will pay Seller the Contract Rate set forth in Exhibit A attached hereto for each MWh of Renewable Energy delivered under the REPA for the calendar years 2010 and 2011. These prices will then increase at 2.25% per year in 2012 and thereafter. Purchaser will also reimburse Seller for any operating reserve or other PJM charges associated with scheduling the Renewable Energy to Purchaser via PJM's eSchedule process.

- Contract Start Date. The REPA will be effective upon the receipt of a final, non-appealable order from the Commission approving the terms and conditions of the REPA and authorizing Purchaser to recover all of the jurisdictional costs associated with the REPA through Kentucky Power Company Base Rates.

- Delay Damages. Customary for transactions of this type.

- Termination Right of Seller before CSD. If Purchaser is unable to obtain by September 15, 2010 a final, non-appealable order from the Commission approving the terms and conditions of the REPA and authorizing Purchaser to recover all of the jurisdictional costs associated with the REPA through Kentucky Power Company Base Rates, Seller may, by notice to the Purchaser delivered no later than September 30, 2009, terminate the REPA.

- Termination Right of Purchaser before CSD. If Purchaser is unable to obtain by September 15, 2010 a final, non-appealable order from the Commission approving the terms and conditions of the REPA and authorizing Purchaser to recover all of the jurisdictional costs associated with the REPA through Kentucky Power Company Base Rates, Purchaser may, by notice to Seller on or prior to September 30, 2010, terminate the REPA.

- Representations and Warranties. Customary for transactions of this type.

- Sale and Purchase of Renewable Energy Products. During the Term of the REPA, Seller will generate, deliver and sell to Purchaser, Purchaser's Contract Capacity Share (100 MW) from the Lee DeKalb Wind Energy Center ("Purchaser's Share") of all Renewable Energy generated by the Facility, together with all associated Capacity, Beneficial Environmental Interests and Ancillary Services (collectively, "Renewable Energy Products").

- Purchaser's Right to Curtail Renewable Energy. Purchaser has the right from time to time to invoke an Economic Curtailment or, upon receipt of notice thereof, a Reliability Curtailment that is directed by the Transmission Operator or Interconnection Provider. In case of Economic Curtailment, Purchaser must provide Seller with notice of the curtailment and Purchaser's Share of Renewable Energy will be reduced to zero (0). In case of Reliability Curtailment, Purchaser must provide Seller with notice of the curtailment and the amount of Renewable Energy, if any, that may continue to be delivered to Purchaser during such Reliability Curtailment.

- Compensation for Curtailments. Purchaser is required to compensate Seller for any periods of Economic Curtailment, based on the amount of energy that Seller would have delivered given the prevailing wind conditions and other factors during the curtailment period. No compensation is owed during periods of Reliability Curtailment.

- Operation. Seller will operate the Facility consistent with Good Utility Practices, including compliance with permits and laws, and the Contract Administration Procedures developed with Purchaser.

- Delivery. Seller is responsible for all costs required to deliver Purchaser's Share of Renewable Energy from the Facility to the Point of Delivery. Purchaser is responsible for all costs required to receive Purchaser's Share of Renewable Energy at the Point of Delivery and deliver such energy to points beyond the Point of Delivery.

- Scheduling Arrangements. Seller is responsible for all scheduling of the Renewable Energy via PJM's eSchedule system. Purchaser is responsible for (1) all costs related to delivery of Purchaser's Share of Renewable Energy at and from the Point of Delivery and (2) for all scheduling, imbalance and congestion costs that are associated with Purchaser's Share, excluding any such costs arising from the failure by Seller to curtail deliveries in connection with a Reliability

Curtailment or Economic Curtailment. Seller is responsible (1) for all costs related to delivery of the Renewable Energy to the Point of Delivery and (2) for all scheduling, imbalance, congestion or other costs incurred by Purchaser as a result of the failure by Seller to curtail deliveries in connection with a Reliability Curtailment or Economic Curtailment.

- Beneficial Environmental Interest Certification. Seller is responsible for subscribing to and providing reports to the Generation Attribute Tracking System (GATS) and delivering GATS Certificates associated with the Renewable Energy delivered to Purchaser.

- Interconnection Facilities. Seller has entered into a separate and free-standing Interconnection Agreement with the Interconnection Provider and is responsible for constructing, operating and maintaining all interconnection facilities thereunder.

- Meters. Customary for transactions of this type.

- Taxes and Tax Credits. Seller is solely responsible for all taxes relating to the Facility, and for taxes incurred by reason of the sale and delivery of Renewable Energy to Purchaser at the Point of Delivery. Purchaser is responsible for all taxes relating to the Renewable Energy Credits, and for taxes associated with the Renewable Energy upon and after receipt at the Point of Delivery. Seller will receive all tax credits from the ownership and operation of the Facility.

- Events of Default of Seller. Customary for transactions of this type.

- Events of Default of Purchaser. Customary for transactions of this type.

- Remedies for Default. Customary for transactions of this type including a termination right in the event a Default remains uncured beyond the applicable period(s).

- Seller Security Fund. Seller will provide a Security Fund as credit support for damages due upon Seller's failure to achieve COD by the Commercial Operation Milestone, damages due upon Seller's failure to maintain the Guaranteed Availability during an applicable period, or damages resulting from a Seller Event of Default.

- Damages Payable in the Event of Termination. Customary for transactions of this type.

- Indemnification. Customary for transactions of this type.

- Fines. Customary for transactions of this type.

- Limitation of Liability, Remedies, and Damages. Customary for transactions of this type.

- Assignment. Customary for transactions of this type.

- Confidentiality. Customary for transactions of this type.

- Governing Law/Venue. The interpretation and performance of the REPA is governed under the laws of the State of New York.

- Dispute Resolution. Customary for transactions of this type.

EXHIBIT A

ADDITIONAL TERMS

[redacted]

PRICING

CONTRACT RATE
($ Per MWh)

Premium Peak	$[redacted] / MWh*	Weekdays: Jan/Feb/Jul/Aug/Dec
Peak	$[redacted] / MWh*	Weekdays: Mar/Apr/May/Jun/Sep/Oct/Nov
Off-Peak	$[redacted] / MWh*	Nights, Weekends & NERC Holidays: Jan - Dec

* Above prices escalates at 2.25% per year beginning 1/1/2012

RENEWABLE ENERGY PURCHASE AGREEMENT FOR WIND ENERGY RESOURCES

BETWEEN

FPL ENERGY ILLINOIS WIND, LLC

AND

KENTUCKY POWER COMPANY

DECEMBER 21, 2009

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

RENEWABLE ENERGY PURCHASE AGREEMENT
BETWEEN
FPL ENERGY ILLINOIS WIND, LLC
AND
KENTUCKY POWER COMPANY

This Renewable Energy Purchase Agreement (the "REPA") is made this 21st day of December, 2009, by and between FPL ENERGY ILLINOIS WIND, LLC ("Seller"), a Delaware limited liability company, with a principal place of business at 700 Universe Boulevard, Juno Beach, Florida 33408, and KENTUCKY POWER COMPANY ("Purchaser"), a Kentucky corporation, with a principal place of business at c/o American Electric Power Service Corporation, 1 Riverside Plaza, Columbus, Ohio 43215-2355. Seller and Purchaser are hereinafter referred to individually as a "Party" and collectively as the "Parties".

WHEREAS Seller is developing and constructing and will own and operate a renewable electric generating facility with an expected total name plate capacity of approximately 217.5 MW, and which is further defined below as the "Facility"; and

WHEREAS the Facility is located at Lee and Dekalb Counties, Illinois, and will interconnect with the Transmission Provider's System; and

WHEREAS Seller desires to sell and deliver to Purchaser at the Point of Delivery Purchaser's Contract Capacity Share of the Renewable Energy Products, and Purchaser desires to buy the same from Seller; and

WHEREAS Purchaser has accepted Seller's offer to sell such Renewable Energy Products in accordance with the terms and conditions set forth in this REPA.

NOW THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

ARTICLE 1
DEFINITIONS AND RULES OF INTERPRETATION

1.1 <u>Rules of Construction</u>.

The capitalized terms listed in this Article shall have the meanings set forth herein whenever the terms appear in this REPA, whether in the singular or the plural or in the present or past tense. Other terms used in this REPA but not listed in this Article shall have meanings as commonly used in the English language and, where applicable, in Good Utility Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) The masculine shall include the feminine and neuter.

(B) References to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this REPA.

(C) The Exhibits attached hereto are incorporated in and are intended to be a part of this REPA; provided, that in the event of a conflict between the terms of any Exhibit and the terms of this REPA, the terms of this REPA shall take precedence.

(D) This REPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this REPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this REPA or any part hereof.

(E) The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this REPA. Unless expressly provided otherwise in this REPA, (i) where the REPA requires the consent, approval, or similar action by a Party, such consent, approval or similar action shall not be unreasonably withheld, conditioned or delayed, and (ii) wherever the REPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(F) Each reference in this REPA to any agreement or document (including those set forth electronically on an internet web site) or a portion or provision thereof shall be construed as a reference to the relevant agreement or document as amended, supplemented or otherwise modified from time to time.

(G) Each reference in this REPA to applicable laws and to terms defined in, and other provisions of, applicable laws (including those set forth electronically on an internet web site) shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time.

(H) Each reference in this REPA to a Person includes its successors and permitted assigns and, in the case of a Governmental Authority, any Person or Persons succeeding, in whole or in part, to its functions and capacities.

(I) In this REPA, the words "include," "includes" and "including" are to be construed as being at all times followed by the words "without limitation."

1.2 Interpretation with Interconnection Agreement.

The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider.

(A) The Parties acknowledge and agree that the Interconnection Agreement shall be a separate and free-standing contract and that the terms of this REPA are not binding upon the Interconnection Provider.

(B) Notwithstanding any other provision in this REPA, nothing in the Interconnection Agreement shall alter or modify Seller's or Purchaser's rights, duties and obligations under this REPA. This REPA shall not be construed to create any rights between Seller and the Interconnection Provider.

(C) Seller expressly recognizes that, for purposes of this REPA, the Interconnection Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Purchaser or an Affiliate of Purchaser.

1.3 <u>Interpretation of Arrangements for Electric Supply to the Facility</u>.

The Parties recognize that this REPA does not provide for the supply of any electric service by Purchaser to Seller or to the Facility and Seller must enter into separate arrangements for the supply of electric services to the Facility, including the supply of turbine unit start-up and shutdown house power and energy.

(A) The Parties acknowledge and agree that the arrangements for the supply of electric services to the Facility shall be separate and free-standing arrangements and that the terms of this REPA are not binding upon the supplier of such electric services.

(B) Notwithstanding any other provision in this REPA, nothing in the arrangements for the supply of retail electric services to the Facility shall alter or modify Seller's or Purchaser's rights, duties and obligations under this REPA. This REPA shall not be construed to create any rights between Seller and the supplier of such retail electric services.

(C) Seller expressly recognizes that, for purposes of this REPA, the supplier of retail electric services to the Facility shall be deemed to be a separate entity and separate contracting party whether or not the arrangements for the supply of retail electric services to the Facility is entered into with Purchaser or an Affiliate of Purchaser.

1.4 <u>Definitions</u>.

The following terms shall have the meanings set forth below when used herein:

"Abandonment" means the permanent and complete cessation by Seller prior to the Commercial Operation Date of the design, construction, testing and inspection of the Facility, but only if such cessation is not caused by or attributable to an Event of Default of, or request by, Purchaser, an Emergency, a Forced Outage, a Scheduled Outage/Derating or an event of Force Majeure.

"Affiliate" of any named person or entity means any other person or entity that controls, is under the control of, or is under common control with, the named entity. The term "control" (including the terms "controls", "under the control of" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management of the policies of a person or entity, whether through ownership interest, by contract or otherwise.

"Ancillary Services" means voltage support, regulation and frequency response services, energy imbalance services, automatic generating control, spinning reserve, non-spinning reserve and replacement reserve, reactive power and any other services that support the transmission of capacity and energy or the reliable operation of the Transmission Provider's transmission system, to the extent included as ancillary services in the Transmission Operator's open access transmission tariff, and in each case, to the extent commonly sold or saleable and to the extent that the assets comprising the Facility are Eligible to provide such services under normal operating conditions.

[redacted]

[redacted]

"Back-Up Metering" shall have the meaning set forth in Section 5.4(C).

"Beneficial Environmental Interests" means all Non-Power Attributes associated in any way, directly or indirectly, with the Facility and all RECs associated with such Non-Power Attributes, excluding (i) investment tax credits, and any other federal or state tax credits, deductions, or exemptions applicable to Seller or any of its Affiliates based on its ownership or operation of the Facility or on the production and sale of Renewable Energy Products to the Purchaser, or (ii) federal or state cash payments, grants under Section 1603 of the American Recovery and Reinvestment Act of 2009 or outright grants of money relating to the ownership, development, construction, expansion, operation, maintenance or financing of the Facility.

"Business Day" means any calendar day that is not a Saturday, a Sunday, or a NERC Holiday.

[redacted]

"Capacity" means the output level, expressed in MW, that the Facility, or the components of equipment thereof, is capable, as of a given moment, of continuously producing and making available at the Point of Delivery, taking into account the operating condition of the equipment at that time, the auxiliary loads and other relevant factors. Capacity includes all installed capacity and unforced capacity attributed to the Facility by the Transmission Operator, the RFC, any Governmental Authority, or that is commonly sold or saleable to third parties.

"Capacity Deficiency" means, at any time, the amount by which the Committed Capacity exceeds the nameplate capacity of the Commissioned Wind Turbines.

"Cash" shall have the meaning set forth in Section 11.1(C)(2).

"Clock Hour" means sixty-minute increments commencing at the top of the hour on the clock (i.e., 12 o'clock)

"Close of the Business Day" means 5:00 PM EPT on a Business Day.

"Commercial Operation" means the period beginning on the Commercial Operation Date and continuing through the Term of this REPA.

"Commercial Operation Date" or "COD" means the date following the date on which Seller provides written notice to Purchaser that all of the milestones specified in Section 4.7 have occurred or otherwise been satisfied pursuant to this Agreement.

"Commercial Operation Milestone" means September 30, 2010.

"Commission" means the Kentucky Public Service Commission.

"Commissioned" means, with respect to any Wind Turbine, that the requirements of Section 4.7 as they apply to such Wind Turbine have been satisfied.

"Committed Capacity" means 100 MW.

"Communications Equipment" means the communication circuits from the Facility to Purchaser for the purpose of telemetering, supervisory control and data acquisition, transmittal of real time data as described in Exhibit H and voice communications as reasonably required by Purchaser.

[redacted]

"Consent and Agreement" shall have the meaning set forth in Section 19.2.

"Contract Administration Committee" means one representative each from Purchaser and Seller pursuant to Section 10.3.

"Contract Administration Procedures" means those procedures developed pursuant to Section 10.3.

"Contract Capacity Share" means a ratio equal to 100 MW divided by the Facility Capacity in MW.

"Contract Rate" means the applicable rate set forth in Exhibit C.

"Contract Start Date" means the earlier of (i) October 1, 2010 and (ii) the third (3rd) Business Day after Seller's receipt of notice that Purchaser has satisfied or waived the condition in Section 6.1.

"Contract Year" means each calendar year of the Term, whether such calendar year is comprised of 365 or 366 Days, commencing with the first calendar year subsequent to the year in which the Contract Start Date occurs, provided that the last Contract Year of the Term may be less than a full calendar year if this REPA is terminated or expires prior to December 31 of such calendar year.

"Control Area" means the system of electrical generation, distribution, and transmission facilities within which generation is regulated in order to maintain interchange schedules with other such systems.

"Day" means a calendar day.

"Delay Damages" shall have the meaning set forth in Section 4.1.

"Delay Damages Commencement Date" shall mean the date forty-five (45) Days after the Commercial Operation Milestone.

"Delivery Period" shall mean the period that commences on at 0000 hours on the Contract Start Date and continues through the remainder of the Term.

"Deviation" shall have the meaning set forth in Section 5.6(B)

"Dispute" shall have the meaning set forth in Section 13.9(A).

"Dispute Notice" shall have the meaning set forth in Section 13.9(A).

[redacted]

[redacted]

[redacted]

"Electric Metering Device(s)" means all meters, metering equipment, and data processing equipment used to measure, record, or transmit data relating to the Renewable Energy from the Facility. Electric Metering Devices does not include the metering current transformers or the metering voltage transformers.

[redacted]

"Emergency" means an emergency condition as defined under the Interconnection Agreement or the OATT.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"Environmental Contamination" means the introduction or presence of Hazardous Materials at such levels, quantities or location, or of such form or character, as to constitute a violation of federal, state or local laws or regulations, and present a material risk under federal, state or local laws and regulations that the Site will not be available or usable for the purposes contemplated by this REPA.

"EPT" means Eastern Prevailing Time.

[redacted]

"Event of Default" shall have the meaning set forth in Article 12.

"Facility" means Seller's proposed electric generating facility and Seller's Interconnection Facilities, as identified and described in Article 3 and Exhibit B to this REPA, including all of the following, the purpose of which is to produce renewable wind power and deliver such wind power to the Point of Delivery: Seller's equipment, buildings, all of the generation facilities, including generators, turbines, step-up transformers, output breakers, facilities necessary to connect to the Point of Delivery, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of the electric generating facility that produces the Renewable Energy subject to this REPA, any and all additions, replacements or modifications thereof.

"Facility Capacity" means the Capacity capable of being generated from the Facility based on the aggregate nameplate rating of all of the Wind Turbines comprising the Facility.

"Facility Debt" means the obligations of Seller to any lender or tax equity investor pursuant to the Financing Documents, including principal of, premium and interest on indebtedness, fees, expenses or penalties, amounts due upon acceleration, prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Facility Debt Representative" means any single trustee or agent on behalf of the Facility Lenders or such other single representative designated in writing by Seller.

"Facility Lenders" means any and all Persons or successors in interest thereof (A) lending money or extending credit (whether directly to Seller or to an Affiliate of Seller) as follows: (i) for the construction, interim or permanent financing or refinancing of the Facility; (ii) for working capital or other ordinary business requirements of the Facility (including the maintenance, repair, replacement or improvement of the Facility); (iii) for any development financing, bridge financing, credit support, credit enhancement or interest rate protection in connection with the Facility; (iv) for any capital improvement or replacement related to the Facility; or (v) for the purchase of the Facility and the related rights from Seller; and/or (B) participating (directly or indirectly) as an equity investor in the Facility; and/or (C) any lessor under a lease finance arrangement relating to the Facility.

"Federal Funds Effective Rate" means the rate for that day opposite the caption "Federal Funds (Effective)" as set forth in the weekly statistical release designated as H. 15 (519), or any successor publication, published by the Board of Governors of the Federal Reserve System.

"FERC" means the Federal Energy Regulatory Commission.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements and other documents relating to the development, bridge, tax equity, construction or permanent debt financing for the Facility, including any credit enhancement, credit support, working capital financing, letter of credit facilities, and all such documents or agreements related to any refinancing or replacement of any of the foregoing, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Force Majeure" shall have the meaning set forth in Article 14.

"Forced Outage" means any condition at the Facility that requires immediate removal of the Facility, or some part thereof, from service, another outage state, or a reserve shutdown state.

"GATS" means the Generation Attribute Tracking System administered by PJM Environmental Information Services, Inc. ("PJM EIS") and providing environmental and emissions attributes reporting and tracking services to its subscribers in support of renewable portfolio standards and other information disclosure requirements that may be implemented by Governmental Authorities. GATS tracks generation attributes and the ownership of the attributes as they are traded or used to meet standards of Governmental Authorities. GATS includes any successor tracking system or systems with the same or similar purpose administered by PJM EIS.

"GATS Certificates" means certificates recognized by GATS and associated with the generation of electricity from the Facility.

"Good Utility Practice(s)" means the practices, methods, and acts (including the practices, methods, and acts engaged in or approved by a significant portion of the wind power generation industry, the Transmission Operator or NERC) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, permits, codes, standards, reliability, safety, environmental protection, economy, and expedition. Good Utility Practices are not intended to be the optimal practice, method or act to the exclusion of all others, but rather are intended to be any of the practices, methods or acts generally accepted in the region in which the Facility is located. With respect to the Facility, Good Utility Practice(s) includes taking reasonable steps to ensure that:

(A) commercially reasonable levels of equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

(B) sufficient operating personnel are available to operate the Facility on a 24 hour basis in accordance with commercially reasonable wind industry operating practices for wind power generation equipment and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently, and in coordination with Purchaser and are capable of responding to reasonably foreseeable emergency conditions whether caused by events on or off the Site;

(C) preventive, routine, and non-routine maintenance and repairs are performed on a commercially reasonable basis that enables reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(D) appropriate and commercially reasonable monitoring and testing are performed to determine that equipment is functioning as designed; and

(E) equipment is not operated in a reckless manner or in a manner unsafe to workers, the general public, or the interconnected system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as, flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAr) loading, frequency, rotational speed, polarity, synchronization, or control system limits.

"Governmental Authority" means any federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power; or any court or governmental tribunal.

[redacted]

"Hazardous Materials" means any substance, material or particulate matter that is regulated by any local governmental authority, any applicable State, or the United States of America, as an environmental pollutant or dangerous to public health, public welfare, or the natural environment including protection of nonhuman forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601); (ix) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a pesticide under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"Indemnified Party" shall have the meaning set forth in Article 17.

"Indemnifying Party" shall have the meaning set forth in Article 17.

"Interconnection Agreement" means the separate generation interconnection agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Transmission Provider's System, as such agreement may be amended from time to time.

"Interconnection Facilities" means the facilities necessary to connect Transmission Provider's System to the Point of Delivery, including breakers, bus work, bus relays, and associated equipment installed by the Interconnection Provider for the direct purpose of interconnecting the Facility, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. Arrangements for the installation and operation of the Interconnection Facilities shall be governed by the Interconnection Agreement.

"Interconnection Provider" means the Transmission Operator or any Transmission Provider responsible for the operation of the Interconnection Facilities and other equipment and facilities with which the Facility interconnects at the Point of Delivery.

"Issuer" means a financial institution or company reasonably acceptable to Purchaser and Seller.

"Locational Marginal Price" or "LMP" means for each hour of a Day, the day-ahead or real-time locational marginal price, as specified herein, expressed in dollars per MWh at the Delivery Point for such hour, as determined by PJM in accordance with the OATT and other applicable PJM Manuals and Agreements.

"Minimum Availability Period" shall have the meaning set forth in Section 12.1(F).

“Moody’s” means Moody’s Investors Service.

"MW" means megawatt, an amount of power equal to 1,000 kilowatts or 1,000,000 watts.

"MWh" means megawatt-hour, an amount of power equal to 1,000 kilowatt-hours or 1,000,000 watt-hours.

"NERC" means the North American Electric Reliability Corporation.

"NERC Holiday" means every Day other than a Saturday or Sunday which the NERC declares to be a holiday for power scheduling purposes.

"Network Resource" shall have the meaning set forth in the OATT.

"Non-Power Attributes" means any characteristic of the Facility related to its benefits to the environment, including any avoided, reduced, displaced or off-set emissions of pollutants to the air, soil or water such as sulfur dioxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO), mercury (Hg), particulates, and any other pollutant that is now or may in the future be regulated under federal, state or local pollution control laws, regulations or ordinances or any voluntary rules, guidelines or programs; and further include any avoided emissions of carbon dioxide (CO_2) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere. Non-Power Attributes do not include (i) investment tax credits, and any other federal or state tax credits, deductions, or exemptions applicable to Seller or any of its Affiliates based on its ownership or operation of the Facility or on the production and sale of Renewable Energy Products to the Purchaser, or (ii) federal or state cash payments , grants under Section 1603 of the American Recovery and Reinvestment Act of 2009 or outright grants of money relating to the ownership, development, construction, expansion, operation, maintenance or financing of the Facility.

"OATT" means the FERC filed Open Access Transmission Service Tariff of the Transmission Operator, as it may be amended and approved by FERC.

"Off Peak Hours" means the hours from hour ending 0100 through hour ending 0700 and the hour ending 2400 Monday through Friday; and hours ending 0100 through hour ending 2400 Saturday, Sunday and NERC Holidays. All times will be in EPT in accordance with applicable PJM requirements.

"Operating Records" means operating logs, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that the Seller uses or maintains for the operation of the Facility.

[redacted]

"Peak Hours" means the hours from the hour ending 0800 through the hour ending 2300, Monday through Friday, for the months March, April, May, June, September, October and November, excluding NERC Holidays. All times will be in EPT in accordance with applicable PJM requirements.

"Penalties" means penalties imposed by Governmental Authorities.

"Person" means an individual, corporation, limited liability company, voluntary association, joint stock company, business trust, partnership, Governmental Authority, or other entity.

"PJM" means PJM Interconnection, LLC.

"PJM Manuals and Agreements" means, collectively, (i) all instructions, rules, procedures and guidelines established by PJM, (ii) all documents and protocols issued by PJM and (iii) all agreements to which Seller, Purchaser or any Affiliates of Purchaser, on the other hand, and PJM, on the other hand, are parties, either bilaterally or in concert with other entities, as may be in effect from time to time, in each case for the operation, planning, and accounting requirements of PJM and the PJM Interchange Energy Market, including the OATT.

"Point of Delivery" means the electric interconnection point, as shown on Exhibit G, at which point the quantities of Renewable Energy and Ancillary Services delivered are recorded and measured by the Interconnection Provider's revenue meters.

"Premium Peak Hours" means the hours from the hour ending 0800 through the hour ending 2300, Monday through Friday, for the months January, February, July, August and December, excluding NERC Holidays. All times will be in EPT in accordance with applicable PJM requirements.

"Proration Factor" means, if the Contract Year in which this REPA is terminated or expires is less than a full calendar year, then, with respect to such Contract Year, an amount equal to a fraction, the numerator of which is the number of Days falling within the Delivery Period in such Contract Year, and the denominator of which is 365 or 366, as applicable to the calendar year that includes such Contract Year.

"Purchaser Security Fund" means the fund that Purchaser is required to establish and maintain, pursuant to Section 11.2, as security for Purchaser's performance under this REPA.

"Reliability Curtailment" means any curtailments of delivery of Renewable Energy resulting from (i) an Emergency, (ii) any other order or directive of the Interconnection Provider or the Transmission Operator, which order or directive may be directly communicated to Seller by the Interconnection Provider, the Transmission Provider or the Transmission Operator or indirectly to Seller by Purchaser promptly upon receipt thereof, (iii) Seller's failure to maintain in full force and effect any permit, consent, license, approval, or authorization from any Governmental Authority required by law to construct or operate the Facility, or (iv) Seller's operation of the Facility by Seller in a manner inconsistent with Good Utility Practices.

"Renewable Energy" means the net Energy generated exclusively by the Facility from wind and delivered to the Point of Delivery as measured by the Electric Metering Devices installed pursuant to Section 5.4.

"Renewable Energy Credit" or "REC" means any credits, credit certificates, rights, powers, privileges or similar items in existence now or as made available after the execution of this Agreement that is related to the Non-Power Attributes of the Facility such as those for greenhouse gas reduction, green certificates or the generation of green power or renewable energy, or for satisfying renewable portfolio standards or similar renewable energy mandates, or offsets of emissions of greenhouse gases, in each case created by any governmental agency and/or independent certification board or group generally recognized in the electric power generation industry, and generated by or associated with the Facility, but specifically excluding (i) investment tax credits, and any other federal or state tax credits, deductions, or exemptions applicable to Seller or any of its Affiliates based on its ownership or operation of the Facility or on the production and sale of Renewable Energy Products to the Purchaser and (ii) cash payments , grants under Section 1603 of the American Recovery and Reinvestment Act of 2009 or outright grants of money relating in any way to the Facility. Without limiting the generality of the foregoing definitions, RECs shall include GATS Certificates.

"Renewable Energy Products" means, collectively, the Renewable Energy and Ancillary Services produced by the Facility and all of the associated Capacity and Beneficial Environmental Interests.

"REPA" means this Renewable Energy Purchase Agreement between Seller and Purchaser.

"Replacement Energy Costs" means, for any Calculation Period, Purchaser's average cost of replacement Renewable Energy, or Energy plus replacement Renewable Energy Credits, over such Calculation Period, calculated in accordance with part (d) of Exhibit I.

[redacted]

"RFC" means the Reliability*First* Corporation, one of the eight regional reliability councils approved by the North American Electric Reliability Corporation (NERC).

"Scheduled Outage/Derating" means a planned interruption or reduction of the Facility's generation by Seller that both (i) has been coordinated in advance with Purchaser, with a mutually agreed start date and duration, and (ii) is required for inspection, or preventive or corrective maintenance.

"Seller's Merchant Capacity" means the portion of the Facility Capacity not committed to Purchaser under this REPA or to a Third Party Purchaser under a Third Party Power Purchase Agreement.

"Seller Security Fund" means the fund that Seller is required to establish and maintain, pursuant to Section 11.1, as security for Seller's performance under this REPA.

"Seller's Interconnection Facilities" means the equipment between the high side disconnect of the step-up transformer and the Point of Delivery, including all related relaying protection and physical structures as well as all transmission facilities required to access the Transmission Provider's System at the Point of Delivery, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. On the high side of the step-up transformer it includes Seller's load control equipment as provided for in the Interconnection Agreement. This equipment is located within the Site and is conceptually depicted in Exhibit B to this REPA.

[redacted]

"Site" means the parcel or parcels of real property on which the Facility will be constructed and located, including any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Section 3.2 and Exhibit B to this REPA.

"Standard & Poor's" or "S&P" means Standard & Poor's, a division of the McGraw-Hill Companies.

"Tax" or "Taxes" shall have the meaning set forth in Section 20.2

"Term" means the period of time during which this REPA shall remain in full force and effect, and which is further defined in Article 2.

"Third Party Power Purchase Agreement" means any written agreement between Seller and a Person other than Purchaser for the purchase of Renewable Energy.

"Third Party Purchaser" means any Person that is a party to, and purchases Renewable Energy under, a Third Party Power Purchase Agreement.

[redacted]

"Transmission Operator" means PJM or any successor independent system operator, regional transmission operator or other transmission operator from time to time having authority to control the transmission Control Area to which the Facility is interconnected.

"Transmission Provider" means any Person or Persons that owns, operates or controls facilities used for the transmission of electrical energy from the Facility in interstate commerce.

"Transmission Provider's System" means the contiguously interconnected electric transmission facilities, including Interconnection Provider's interconnection facilities, over which the Transmission Provider has rights to provide for the bulk transmission of capacity and energy from the Point of Delivery.

"Uncommitted Capacity" means the portion of the Facility Capacity in excess of Purchaser's Contract Capacity Share of the Facility Capacity.

"Wind Turbines" means those generating devices powered by the wind that are included in the Facility.

ARTICLE 2
TERM AND TERMINATION

This REPA shall become effective as of the date of its execution, and shall remain in full force and effect until the twentieth (20th) anniversary of the last day of the month in which the Contract Start Date occurs, subject to any early termination or extension provisions set forth herein; provided, however, that Seller's obligation to deliver and Purchaser's obligation to purchase Renewable Energy Products shall not commence until the beginning of the Delivery Period except as specifically provided herein. Applicable provisions of this REPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this REPA, repayment of principal and interest associated with security funds, the indemnifications specified in this REPA, limitations of liability, and the resolution of disputes between the Parties.

ARTICLE 3
FACILITY DESCRIPTION

3.1 <u>Summary Description</u>.

Seller shall construct, own, operate, and maintain the Facility, which is expected to consist initially of one hundred forty-five (145) GE 1.5 XLE Wind Turbines, each rated at 1,500 kW and associated equipment having an initial nameplate capacity of approximately 217.5 MW. Exhibit B to this REPA provides a detailed description of the Facility, including identification of the equipment and components, which make up the

Facility. Seller shall have the right, in its sole discretion, to install additional Wind Turbines at the Facility, provided, however, that the aggregate nominal or "nameplate" MW rating of the Wind Turbines comprising the Facility will not exceed 240 MW at any time during the Term. Any additional wind turbines installed on the Site in excess of such 240 MW shall not comprise the Facility or share the same Point of Delivery or revenue meter used in connection with this REPA.

3.2 Location.

The Facility shall be located on the Site and shall be identified as Seller's Lee-Dekalb Wind Energy Center. The Facility is located in Lee and Dekalb Counties, Illinois. A scaled map that identifies the Site, the location of the Facility at the Site, the location of the Point of Delivery and the location of the important ancillary facilities and Interconnection Facilities, is included in Exhibit B to this REPA.

3.3 General Design of the Facility.

Seller shall construct the Facility according to Good Utility Practice(s), the Interconnection Agreement and rules of the Transmission Operator, including the PJM Manuals and Agreements. In addition to the requirements of the Interconnection Agreement, the design of the Facility shall at all times include:

(A) the required panel space and 125V DC battery supplied voltage to accommodate Purchaser's metering, generator telemetering equipment and Communications Equipment;

(B) the Communications Equipment; and

(C) metering accuracy current transformers and voltage transformers located at the Point of Delivery (or some other point mutually agreed to by the Parties) as required to connect to the Electric Metering Devices.

ARTICLE 4
COMMERCIAL OPERATION

4.1 Commercial Operation.

Subject to the satisfaction of the conditions set forth in Section 6.2 and extension as otherwise specifically provided for herein, the Facility shall achieve the Commercial Operation Date no later than the Commercial Operation Milestone. Subject to the limitations provided for in the immediately succeeding sentence, in the event that the Facility does not achieve the Commercial Operation Date on or before the Delay Damages Commencement Date, Seller shall pay Purchaser as liquidated damages [redacted] per MW of Capacity Deficiency per Day for each Day after the Delay Damages Commencement Date until the Commercial Operation Date ("Delay Damages"). [redacted]

[redacted]

4.2 [Intentionally Deleted].

4.3 Site Report.

Seller shall provide Purchaser, on or before sixty (60) days after the execution of this REPA, with a copy of the report summarizing its Phase I environmental investigation of the Site, together with any data or information generated pursuant to such investigation.

4.4 [Intentionally Deleted].

4.5 Progress Reports.

Commencing upon the execution of this REPA, Seller shall submit to Purchaser, within the first fifteen (15) Days of each calendar month until the Commercial Operation Date is achieved, reports regarding the progress of development and construction of the Facility in a form reasonably satisfactory to Purchaser. These progress reports shall describe the status of the development and construction of the Facility as of the end of the preceding month, including (a) a description of the progress of development and construction, (b) an explanation of any changes in the development and construction schedule and (c) an estimate of the Commercial Operation Date. Commencing upon the execution of this REPA, Seller will additionally advise Purchaser weekly on the status of Wind Turbine Commissioning until the Commercial Operation Date is achieved.

4.6 Purchaser's Rights During Construction.

Upon reasonable prior written notice, Purchaser shall have the right to monitor the construction, start-up and testing of the Facility during normal business operating hours, and Seller shall comply with all reasonable requests of Purchaser with respect to the monitoring of these events, provided, however, that Purchaser shall not unreasonably interfere with or disrupt the activities of the Seller. Seller shall cooperate in such physical inspections of the Facility as may be reasonably requested by Purchaser during and after completion of construction. All persons visiting the Facility on behalf of Purchaser shall comply with all of Seller's applicable safety and health rules and requirements. Purchaser's technical review and inspection of the Facility shall not be construed as endorsing the design thereof nor as any warranty of safety, durability, or reliability of the Facility.

4.7 Commercial Operation Milestones.

Seller shall use commercially reasonable efforts to achieve the following milestones within a reasonable time after the effectiveness of this REPA:

(A) Wind Turbines with an aggregate nameplate capacity of at least [redacted] MW are tested and commissioned at the Facility and are able to produce and deliver Energy to the Point of Delivery in compliance with this Agreement;

(B) the Facility has achieved initial synchronization with the Transmission Provider's System;

(C) the interconnection of the Facility to the Transmission Provider's System has been completed in material compliance with the Interconnection Agreement and has operated at a generation level acceptable to the Interconnection Provider in material compliance with the operating requirements of the Interconnection Agreement, in either case, such that there is no material adverse effect on Seller's or Purchaser's ability to perform its obligations under this REPA;

(D) Seller can demonstrate that it can reliably transmit real time data and measurements with Purchaser in accordance with the requirements of Exhibit H;

(E) all arrangements for the supply of required electric services to the Facility, including the supply of turbine unit start-up and shutdown power and energy, house power and maintenance power have been completed by Seller separate from this REPA, are in effect, and are available for the supply of such electric services to the Facility;

(F) the Seller Security Fund has been established pursuant to Section 11.1;

(G) certificates of insurance evidencing the coverages required by Article 16 have been obtained and submitted to Purchaser;

(H) all permits, consents, licenses, approvals, and authorizations required to be obtained by Seller from any Governmental Authority to construct and operate the Facility in compliance with applicable law and this REPA have been obtained;

(I) Seller has made all necessary filings and applications with Governmental Authorities for accreditation and participation in GATS and in any applicable federal or state REC certification program pursuant to Section 10.9; and

[redacted]

[redacted]

4.8 [Intentionally Deleted].

4.9 QF Waiver.

For so long as this REPA is in effect, Seller waives, and agrees not to assert, the rights Seller may have against Purchaser to cause Purchaser to purchase or transmit energy or capacity pursuant to 18 C.F.R. section 292.303 or section 292.304 by virtue of the status of the Facility as a qualifying cogeneration facility as defined in the Public Utility Regulatory Policies Act of 1978, as amended.

ARTICLE 5
DELIVERY AND METERING

5.1 Seller's and Purchaser's Obligations.

Subject to, and in accordance with, the terms and conditions of this REPA, including Section 5.3(A), Purchaser does hereby agree to purchase and pay for Purchaser's Contract Capacity Share of Renewable Energy Products, and Seller does hereby agree to sell and deliver to the Point of Delivery, or cause to be delivered to the Point of Delivery, Purchaser's Contract Capacity Share of the Renewable Energy Products during the Delivery Period. Subject to Section 7.1, Purchaser shall have the exclusive right to purchase and receive all of Purchaser's Contract Capacity Share of Renewable Energy Products, with the exception of Energy produced by Seller for its own use at the Facility for station power. Seller shall not offer, sell or make available any of Purchaser's Contract Capacity Share of Renewable Energy Products or dispatch Purchaser's Contract Capacity Share thereof to or for the benefit of Seller (except for its own use at the Facility for station power) or any other Person, other than to Purchaser. For the avoidance of doubt, Purchaser hereby acknowledges and agrees that Seller may offer, sell and make available to third parties any of the Uncommitted Capacity of Renewable Energy Products or dispatch any of the Uncommitted Capacity thereof to or for the benefit of Seller. Notwithstanding any provision herein to the contrary and without in any way restricting or limiting Purchaser's ability to declare an Economic Curtailment, Purchaser's failure, inability or unwillingness to pay congestion charges, location marginal pricing differentials or any other congestion costs or charges shall not excuse Purchaser's obligation to purchase and accept the Renewable Energy Products hereunder.

5.2 Required Operation.

Except to the extent the Facility is actually unavailable or limited (including in accordance with Good Utility Practice(s) and due to curtailments under Section 7.4(A)), Seller shall operate the Facility to provide the Renewable Energy Products to Purchaser in all hours of the Delivery Period. Seller agrees that, notwithstanding anything herein to the contrary, Seller will not curtail or otherwise reduce deliveries of Renewable Energy Products in order to sell such Renewable Energy Products to other purchasers.

5.3 Delivery Arrangements.

[redacted]

[redacted]

(C) Seller shall be responsible for paying any and all transmission upgrade costs identified by the Transmission Operator as Seller's responsibility in order to designate the Facility as a Network Resource.

5.4 Electric Metering Devices.

(A) Seller will comply with the terms and conditions of the Interconnection Agreement. The following provisions on Electric Metering Devices shall apply only to the extent they do not conflict with the performing party's rights and obligations under the Interconnection Agreement or the OATT, as applicable.

(B) Seller shall provide Purchaser with reasonable advance notice of, and permit a representative of Purchaser to witness and verify, inspections and tests of the Electric Metering Devices, provided, however, that Purchaser shall not unreasonably interfere with or disrupt the activities of Seller and shall comply with all of Seller's safety standards. Upon request by Purchaser, Seller shall perform additional inspections or tests of any Electric Metering Device and shall permit a qualified representative of Purchaser to inspect or witness the testing of any Electric Metering Device, provided, however, that Purchaser shall not unreasonably interfere with or disrupt the activities of Seller and shall comply with all of Seller's safety standards. The actual expense of any such requested additional inspection of testing shall be borne by Purchaser, unless upon such inspection or testing an Electric Metering Device is found to register inaccurately by more than the allowable limits established in this Article, in which event the expense of the requested additional inspection or testing shall be borne by Seller. If requested by Purchaser in writing, Seller shall provide copies of any inspection or testing reports to Purchaser.

(C) Purchaser and Seller each may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering") in addition to the Electric Metering Devices. Each Party, at its own expense, shall inspect and test its Back-Up Metering upon installation and at least annually thereafter. Each Party shall provide the other Party with reasonable advance notice of, and permit a representative of the other Party to witness and verify, such inspections and tests, provided, however, that the observing Party shall not unreasonably interfere with or disrupt the activities of the testing Party and shall comply with all of the testing Party's safety standards. Upon request by a Party, the other Party shall perform additional inspections or tests of its Back-Up Metering and shall permit a qualified representative of the requesting Party to inspect or witness the testing of such Back-Up Metering, provided, however, that the observing Party shall not unreasonably interfere with or disrupt the activities of the testing Party and shall comply with all of the testing Party's safety standards. The actual expense of any such requested additional inspection or testing shall be borne by the requesting Party, unless, upon such inspection or testing, the Back-Up Metering is found to register inaccurately by more than the allowable limits established in this Article, in which event the expense of the requested additional inspection or testing shall be borne by the testing Party. If requested by the requesting Party in writing, the testing Party shall provide copies of any inspection or testing reports to the requesting Party.

(D) If any Electric Metering Devices, or any Back-Up Metering, are found to be defective or inaccurate, they shall be adjusted, repaired, replaced, or recalibrated as near as practicable to a condition of zero error by the Party owning such defective or inaccurate device and at that Party's expense. The Party discovering such defect or inaccuracy shall promptly notify the other Party of such discovery's expense.

5.5 <u>Adjustment for Inaccurate Meters</u>.

(A) The following provisions on Adjustment for Inaccurate Meters shall apply only to the extent they do not conflict with the performing Party's rights and obligations under the Interconnection Agreement or the OATT, as applicable.

(B) If an Electric Metering Device, or Back-Up Metering, fails to register, or if the measurement made by an Electric Metering Device, or Back-Up Metering, is found upon testing to be inaccurate by more than one percent (1.0%) from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements by the inaccurate or defective Electric Metering Device, or Back- Up Metering, for both the amount of the inaccuracy and the period of the inaccuracy, in the following manner:

(C) In the event that the Electric Metering Device is found to be defective or inaccurate, the Parties shall use the Back-Up Metering, if installed, to determine the amount of such inaccuracy, provided, however, that the Back-Up Metering has been tested and maintained in accordance with the provisions of this Article. If both Parties have installed Back-Up Metering, and the Back-Up Metering of both Parties is inaccurate by not more than one percent (1.0%) from the measurements made by the standard meter used in the test, the readings from the Back-Up Metering whose readings most closely conforms with the measurements made by the standard meter shall be used. In the event that neither Party has installed Back-Up Metering, or the Back-Up Metering is also found to be inaccurate by more than one percent (1.0%) from the measurement made by the standard meter used in the test, the Parties shall estimate the amount of the necessary adjustment on the basis of deliveries of Renewable Energy from the Facility during periods of similar operating conditions when the Electric Metering Device was registering accurately. The adjustment shall be made for the period during which inaccurate measurements were made.

(D) In the event that the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) the one hundred eighty (180) Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

(E) To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Purchaser, Purchaser shall use the corrected measurements as determined in accordance with this Article to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments by Purchaser for this period from such re-computed amount. If the difference is a positive number, the difference shall be paid by Purchaser to Seller; if the difference is a negative number, that difference shall be paid by Seller to Purchaser, or at the discretion of Purchaser, may take the form of an offset to payments due Seller by Purchaser (or by payment to Purchaser, if sufficient payments do not remain to offset). Payment of such difference by the owing Party shall be made not later than thirty (30) Days after the owing Party receives notice of the amount due, unless Purchaser elects payment via an offset.

5.6 Scheduling Arrangements.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ARTICLE 6
CONDITIONS PRECEDENT

6.1 Purchaser Condition Precedent.

No later than thirty (30) Days after execution of this REPA, Purchaser may, but shall not be obligated to, request recovery of costs associated with this REPA without modification from the Commission. If Purchaser fails to make a timely cost recovery request, condition precedent in this Section 6.1 shall be deemed waived and this REPA shall remain in full force and effect thereafter. In the event that Purchaser makes such a timely cost recovery request, but despite commercially reasonable efforts, is unable to obtain the following by September 15, 2010, Purchaser, by notice to Seller delivered on or prior to September 30, 2010, may terminate this REPA, without any further financial or other obligation by either Party as a result of such termination:

> A final, non-appealable order from the Commission approving the terms and conditions of the REPA and authorizing Purchaser to recover all of the jurisdictional costs associated with this REPA through Kentucky Power Company Base Rates.

If Purchaser fails to deliver such a notice of termination, the condition precedent in this Section 6.1 shall be deemed waived and this REPA shall remain in full force and effect thereafter.

6.2 Seller Condition Precedent.

[redacted]

ARTICLE 7
SALE AND PURCHASE OF RENEWABLE ENERGY

7.1 Sale and Purchase.

Beginning on the Contract Start Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to Purchaser, and, subject to the terms and conditions of this REPA, including Section 5.3(A) and Section 5.6, Purchaser shall purchase and pay for, at the Contract Rate, Purchaser's Contract Capacity Share of all Renewable Energy generated by the Facility. Purchaser shall have no obligation to pay for any Energy that has not actually been generated by the Facility, measured by the Electric Metering Device(s) and delivered to Purchaser at the Point of Delivery, except in connection with an Economic Curtailment. To the extent Renewable Energy is delivered by Seller to the Point of Delivery contrary to an Economic Curtailment or Reliability Curtailment, Purchaser shall pay for such Renewable Energy at the rates provided herein, but such purchase price shall be reduced by all direct out of pocket net costs (including any positive difference between the Contract Rate and the real-time LMP) incurred by Purchaser as a result of using or disposing of any Renewable Energy deliveries contrary to an Economic Curtailment or Reliability Curtailment.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

7.3 Title and Risk of Loss.

As between the Parties, Seller shall be deemed to be in control of the Renewable Energy output from the Facility up to the Point of Delivery, and Purchaser shall be deemed to be in control of Purchaser's Contract Capacity Share of such Renewable Energy output from and after the Point of Delivery. Title and risk of loss related to the Renewable Energy delivered by Seller to Purchaser hereunder shall transfer from Seller to Purchaser at the Point of Delivery.

7.4 Curtailments.

[redacted]

[redacted]

[redacted]

7.5 Reductions for Curtailments.

(A) In the event of a Reliability Curtailment, Force Majeure event, a Forced Outage, a Schedule Outage/Derating or other planned or unplanned outage of the Facility, Seller shall allocate the curtailment ratably among purchasers of Facility output, by delivering to Purchaser its Contract Capacity Share of the non-curtailed level of output.

(B) During periods of Economic Curtailment by Purchaser, (i) Purchaser's Contract Capacity Share shall be reduced to zero (0), (ii) Seller shall curtail operation of Wind Turbine capacity representing a percentage of the Facility Capacity most closely corresponding to the portion of Purchaser's Contract Capacity Share of Facility Capacity, and (iii) Seller may continue to operate the Uncommitted Capacity.

(C) During periods of a curtailment comparable to an Economic Curtailment of a portion of the output of the Facility by Seller, with respect to Seller's Merchant Capacity, or required by a Third Party Purchaser under its Third Party Power Purchase Agreement, to the extent Seller curtails output from the Facility as a result of such curtailment, the Contract Capacity Share shall be increased to an amount determined by removing such curtailed amount from the Facility Capacity for purposes of calculating the Contract Capacity Share for such period, and (ii) Seller shall, with respect to Seller's Merchant Capacity, and to the extent it is required to do so under such Third Party Purchaser Power Purchase Agreement, curtail operating Wind

Turbines with an aggregate capacity representing a percentage of the Facility Capacity most closely corresponding to the portion of the Facility Capacity that Seller would have received from Seller's Merchant Capacity, and that such Third Party Purchaser would have been entitled to receive under its Third Party Power Purchase Agreement, in the absence of such required curtailment.

7.6 Tax Benefits. If, for any reason, Seller does not receive the (i) investment tax credits or any other federal or state tax credits, deductions, or exemptions applicable to Seller or any of its Affiliates based on its ownership or operation of the Facility or on the production and sale of Renewable Energy Products to the Purchaser, or (ii) federal or state cash payments or outright grants of money relating to the ownership, development, construction, expansion, operation, maintenance or financing of the Facility, the cost of Renewable Energy Products delivered to Purchaser under this REPA shall not be affected, and the risk of not obtaining such tax credits or other benefits or incentives shall be borne solely by Seller.

ARTICLE 8
PAYMENT CALCULATIONS

[redacted]

[redacted]

ARTICLE 9
BILLING AND PAYMENT

9.1 Billing Invoices.

The monthly billing period shall be the calendar month. No later than ten (10) Business Days after the end of each calendar month, Seller shall provide to Purchaser, by first-class mail or electronically, an invoice for the amount due Seller by Purchaser for the services provided by Seller and purchased by Purchaser, under this REPA, during the previous calendar month billing period, including PJM charges and credits pursuant to Section 5.6. Seller's invoice will show all billing parameters, Contract Rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to Seller. Seller's failure to timely provide Purchaser with the monthly invoice shall not waive Purchaser's responsibility for payment under the terms stated in Section 9.2 below, except as provided in Section 13.9(B).

9.2 Payments.

Unless otherwise specified herein, payments due under this REPA shall be due and payable on or before the later of (i) the twentieth (20th) Day of the month following the month to which such payment relates and (ii) the tenth (10th) Business Day following receipt of the billing invoice. Unless Seller directs Purchaser otherwise, all payments by Purchaser to Seller shall be made by electronic funds transfer. If the amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated using an annual interest rate equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such Day (or if not published on such day on the most recent preceding Day on which published) (or if generally unavailable, any other basis mutually agreed to by the Parties), plus two percent (2%). If the due date occurs on a Day that is not a Business Day, the late payment charge shall begin to accrue on the next succeeding Business Day.

9.3 Billing Disputes.

Purchaser may dispute invoiced amounts, but shall pay to Seller the undisputed portion of invoiced amounts on or before the invoice due date. To resolve any billing dispute, the Parties shall use the procedures set forth in Section 13.9. When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount owed in accordance with the provisions of Section 9.2 from the date such amount was originally due. Purchaser and Seller at any time may offset against any and all amounts that may be due and owed to the other Party under this REPA any amounts that are owed by such other Party to Purchaser or Seller, as applicable, pursuant to this REPA including damages and other payments. Undisputed and non-offset portions of amounts invoiced under this REPA shall be paid on or before the due date or shall be subject to the late payment interest charges set forth in Section 9.2.

ARTICLE 10
OPERATIONS AND MAINTENANCE

10.1 Facility Operation.

Seller shall staff, control, and operate the Facility consistent at all times with Good Utility Practice(s) and the Contract Administration Procedures developed pursuant to Section 10.3. Personnel capable of starting, operating, and stopping the Facility shall be available, either at the Facility or capable of remotely starting and stopping the Facility within no more than fifteen (15) minutes after Seller's receipt of notice of the beginning or end of any curtailment. In all cases, personnel capable of starting, operating, and stopping the Facility shall be continuously reachable by phone or pager. Seller shall maintain the Communications Equipment in good operating order at all times during the Term.

10.2 Outage and Performance Reporting.

(A) Seller shall comply with all NERC, RFC and the Transmission Operator generating unit outage and performance reporting requirements, as they may be revised from time to time, and as they apply to the Facility.

(B) When Forced Outages of ten percent (10%) or greater of the Wind Turbines that are part of the Facility occur, Seller shall notify Purchaser of the existence, nature, and expected duration of the Forced Outage as soon as practical, but in no event later than (i) thirty (30) minutes after the Forced Outage occurs if it occurs during normal business hours or (ii) the beginning of normal business hours if such Forced Outage occurs outside of normal business hours. Seller shall thereafter inform Purchaser of changes in the expected duration of the Forced Outage unless relieved of this obligation by Purchaser for the duration of each Forced Outage.

(C) Seller shall provide Purchaser with prompt notice of any malfunction or other failure of the Communications Equipment.

10.3 Contract Administration Committee and Contract Administration Procedures.

(A) Purchaser and Seller shall each appoint one representative and one alternate representative to act in matters relating to the Parties' performance obligations under this REPA and to develop operating arrangements for the generation, delivery and receipt of Renewable Energy hereunder. Such representatives shall constitute the Contract Administration Committee, and shall be as specified on Exhibit D. The Parties shall notify each other in writing of such appointments and any changes thereto. The Contract Administration Committee shall have no authority to modify the terms or conditions of this REPA.

(B) Prior to the Commercial Operation Date, the Contract Administration Committee shall develop mutually agreeable written Contract Administration Procedures which shall include, but not be limited to, method of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list for applicable Purchaser and Seller operating centers; operations and maintenance scheduling and reporting; Renewable Energy reports; unit operations log; and such other matters as may be mutually agreed upon by the Parties.

10.4 Access to Facility.

Appropriate representatives of Purchaser shall at all reasonable times, including weekends and nights, and with reasonable prior notice, have access to the Facility to read meters, to perform maintenance and service of Purchaser's equipment and to perform all inspections and operational reviews as may be reasonably appropriate to facilitate the performance of this REPA. Purchaser will not interfere in any material respect with the operation of the Facility, and will cause all persons visiting the Facility on its behalf to comply with all of Seller's applicable safety, health and similar rules and requirements.

10.5 Reliability Standards. Seller shall operate the Facility in a manner that complies with all national and regional reliability standards, including standards set by the Transmission Operator, RFC, NERC and the FERC, or any successor agencies setting reliability standards for the operation of generation facilities. To the extent that Seller does not operate the Facility in accordance with such standards that result in monetary penalties being assessed to Purchaser by the Transmission Operator, RFC, NERC, or the FERC, Seller shall reimburse Purchaser for its share of such monetary penalties.

10.6 Beneficial Environmental Interests.

The Parties acknowledge that future and or existing legislation or regulation may create value in the ownership, use or allocation of the Beneficial Environmental Interests of the Facility. Purchaser shall own or be entitled to claim Purchaser's Contract Capacity Share of all Beneficial Environmental Interests to the extent they may exist during the Term.

10.7 Availability Reporting.

(A) On the first Business Day of each month commencing after the Commercial Operation Date, Seller will furnish Purchaser with a notice setting forth its good faith estimate of (i) the hourly availabilities of the Facility for such month and the next month and (ii) the expected average daily availability of the Facility for each of the ten (10) months subsequent to such next month. With respect to the preceding clause (A)(i), if Seller later updates its availability estimates for such periods, it shall deliver to Purchaser a revised notice setting forth its then current good faith estimate of hourly availabilities of the Facility for the balance of such month and for the next month. Seller does not guarantee the accuracy of said notices and said notices are only intended to be its good faith estimate of the projected availability of the Facility at the time such notice is given.

(B) Seller shall furnish to Purchaser a notice substantially in the form attached hereto as Exhibit K (an "Availability Notice") at or before 9:00 a.m. EPT on the Business Day immediately prior to the first Day to which such Availability Notice shall relate that shall set forth the Facility Capacity that Seller anticipates will actually be available in each hour through the next Business Day and each subsequent Business Day to which such Availability Notice relates. Seller also shall furnish to Purchaser a revised Availability Notice promptly after the occurrence of any Force Majeure event, Forced Outage, unscheduled outage or other unplanned maintenance, derating, or other event that would reduce or interrupt Renewable Energy or Ancillary Services associated with Purchaser's Contract Capacity Share of Facility Capacity or cause the controlling Availability Notice to be inaccurate or incomplete in any material respect, with a description of the circumstances thereof. Each such Availability Notice shall be effective until delivery of a subsequent Availability Notice. Seller does not guarantee the accuracy of said Availability Notices, and said Availability Notices are only intended to be its good faith estimate of the projected availability of the Facility at the time such notice is given.

10.8 Planned Maintenance Schedule.

No later than (a) fourteen (14) Days after the execution of this REPA and (b) two months prior to each calendar year thereafter during the Term, Seller shall submit to Purchaser a schedule of planned maintenance for the following calendar year for the Facility, which schedule shall be updated by Seller by each March 31 and September 30 thereafter to cover the twelve month period following each such update. Such schedule shall be consistent with the requirements of Good Utility Practice and the Interconnection Agreement, and otherwise in accordance with this REPA. No planned maintenance of the Facility substation or any other portion of the Facility that would affect the availability of more than 10% of the Facility Capacity at any one time may be scheduled during the period June, July, and August during any Contract Year during the Delivery Period; provided, however, that planned maintenance may be scheduled during such period to the extent (i) required by or necessary to preserve any equipment warranties or (ii) the failure to perform such planned maintenance is contrary to operation in accordance with Good Utility Practice(s). Such schedule, and each supplement thereto, shall indicate the planned commencement and completion dates for each planned maintenance during the period covered thereby, as well as the affected portion(s) of the Facility. If Purchaser desires to change the scheduled commencement or duration of planned maintenance, the Purchaser shall notify the Seller of the requested change and the Seller shall use reasonable efforts to accommodate the requested change. At least one (1) week prior to any planned maintenance, Seller shall telephonically notify Purchaser of the expected commencement date of such planned maintenance, the affected portion(s) of the Facility during such planned maintenance and the expected completion date of such planned maintenance. As soon as practicable, all such telephonic notification shall be confirmed in writing.

10.9 Certification of RECs.

(A) Seller shall be responsible for causing the GATS Certificates delivered under this REPA to meet all requirements for entry into GATS and as otherwise specified by the PJM-EIS. Seller shall be responsible for registering and maintaining compliance during the duration of this REPA with GATS and the PJM-EIS and will be responsible for timely delivery as allowed by GATS and the PJM-EIS. The Parties will effectuate the delivery and receipt of the GATS certificates by making and confirming appropriate entries into GATS and otherwise as specified by the PJM-EIS.

(B) Seller shall, at its own cost, take all actions necessary to register for and maintain participation in any applicable system or program established by the federal Governmental Authority or the State of Kentucky to monitor, track, certify or trade RECs or Renewable Energy certificates. To the extent necessary, Seller shall assign to Purchaser all rights, title and authority for Purchaser to register, own, hold and manage certificates that represent RECs respecting Renewable Energy in Purchaser's own name and to Purchaser's account, including any rights associated with any renewable energy information or tracking system that may be established with regard to monitoring, tracking, certifying, or trading such RECs or Renewable Energy certificates.

Upon the request of Purchaser from time to time, at no cost to Purchaser, (i) Seller shall deliver or cause to be delivered to Purchaser such attestations/certifications of RECs as may be required to comply with any certification system or program, and (ii) Seller shall provide full cooperation in connection with Purchaser's registration and certification of RECs or Renewable Energy certificates.

10.10 Public Statements/Other Use.

Without the written consent of Purchaser, Seller shall not (1) make any public statements or representations with respect to the Renewable Energy Products (or any portion thereof) inconsistent with the provisions of this REPA, (2) use the Purchaser's Contract Capacity Share of the Facility's Beneficial Environmental Interests to meet any federal, state or local renewable energy requirement, renewable energy procurement, renewable energy portfolio standard or other renewable energy mandate or (3) advertise, market, sell, retire, convey or otherwise transfer or seek to transfer the Purchaser's Contract Capacity Share of the Facility's Beneficial Environmental Interests, which rights are expressly reserved to Purchaser during the Term of this REPA.

10.11 Real-Time Information.

Seller will use commercially reasonable efforts on and after the later to occur of (1) the Contract Start Date and (2) the Commercial Operation Date to continuously transmit real-time data to Purchaser in compliance with Exhibit H. Purchaser and Seller shall each bear the cost of and responsibilities for their respective systems, equipment and communications links required for receipt of such real-time information.

10.12 Web-Based Operational Reporting.

Purchaser may at its option make available to Seller on the Internet a web-based reporting system which will provide the Parties with the capability to generate and submit standardized reports for purposes of satisfying the requirements of the Parties contained in Sections 10.2, 10.7 and 10.8. Purchaser will develop user requirements for such reporting system in consultation with Seller.

ARTICLE 11
SECURITY FOR PERFORMANCE

11.1 Seller Security Fund.

(A) Seller shall establish, fund, and maintain a Seller Security Fund, pursuant to the provisions of this Article 11, which shall be available to pay any amount due Purchaser pursuant to this REPA. The Seller Security Fund shall also provide security to Purchaser to cover (i) Delay Damages, should the Facility fail to achieve the Commercial Operation Date by the Commercial Operation Milestone; [redacted]; and (iii) other amounts or damages that Purchaser may be entitled to recover hereunder as the result of an Event of Default by Seller under this REPA. Seller shall establish, and maintain throughout the Term, the Seller Security Fund at an [redacted]

[redacted] [redacted] than ten (10) Business Days after the date that all of the Seller's conditions precedent set forth in Section 6.2 have either been satisfied or waived.

(B) In addition to any other remedy available to it, Purchaser may, before or after termination of this REPA, draw from the Seller Security Fund such amounts as are necessary to recover amounts Purchaser is owed pursuant to this REPA, including any damages due to Purchaser and any amounts for which Purchaser is entitled to indemnification under this REPA, but only in the event such amounts have not been paid within five (5) Business Days of a written request therefor presented to Seller. Purchaser may, in its sole discretion, draw all or any part of such amounts due to it from any form of security to the extent available pursuant to this Section 11.1(B), and from all such forms, and in any sequence Purchaser may select. Any failure to draw upon the Seller Security Fund or other security for any damages or other amounts due to Purchaser shall not prejudice Purchaser's rights to recover such damages or amounts in any other manner.

(C) The Seller Security Fund shall be maintained at Seller's expense, shall be issued by or deposited in an Issuer, and shall be in the form of one or more of the following instruments. Seller may change the form of the Seller Security Fund at any time and from time to time upon reasonable prior notice to Purchaser, but the Seller Security Fund must at all times be comprised of one or any combination of the following:

(1) An irrevocable standby letter of credit, in form and substance reasonably acceptable to Purchaser, from an Issuer with a senior unsecured debt rating equivalent to A- (S&P) or A3 (Moody's) or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's (or if either one or both are not available, equivalent ratings from alternate rating sources acceptable to Purchaser). In addition, if such senior unsecured debt rating of the Issuer is exactly equivalent to A-/A3, the Issuer must not be on credit watch by a rating agency. Security provided in this form shall be consistent with this REPA and include a provision for at least thirty (30) Days advance notice to Purchaser of any non-renewal, expiration or earlier termination of the security so as to allow Purchaser sufficient time to exercise its rights under said security if Seller fails to extend or replace the security. The form of such security must meet Purchaser's requirements to ensure that claims or draw-downs can be made unilaterally by Purchaser in accordance with the terms of this REPA. Such security must be issued for a minimum term of three hundred and sixty (360) Days. Seller shall cause the renewal or extension of the security for additional consecutive terms of three hundred and sixty (360) Days or more (or, if shorter, the remainder of the Term of this REPA) no later than thirty (30) Days prior to each expiration date of the security. If the security is not renewed or extended as required herein, Purchaser shall have the right to draw immediately upon the security and be entitled to hold the amounts so drawn as security, provided Purchaser satisfies the conditions of Section 11.1(C)(2)(i). If Purchaser does not meet the conditions of Section 11.1(C)(2)(i), Purchaser will place the amounts so drawn, in an interest bearing escrow account in accordance with Section 11.1(C)(2)(ii), until and unless, upon return to Seller of such security, Seller provides a substitute form of such security meeting the requirements of this Article. Security in the form of an

irrevocable standby letter of credit shall be governed by the Uniform Customs and Practice for Documentary Credits (2007 Revision), International Chamber of Commerce Brochure No. 600.

(2) United States currency ("Cash"), deposited (i) with Purchaser provided that Purchaser satisfies the following conditions: (a) it is not a defaulting party, and (b) Purchaser has a senior unsecured debt rating from Standard and Poor's of at least BBB- and from Moody's of at least Baa3. Purchaser will pay interest to Seller on Cash held at the Federal Funds Effective Rate; or (ii) if, and only if, Purchaser does not meet the aforementioned conditions of Section 11.1(C)(2)(i), then the Cash shall be held with Issuer, either: (a) in an account under which Purchaser is designated as beneficiary with sole authority to draft from the account or otherwise access the security; or (b) held by Issuer as escrow agent with instructions to pay claims made by Purchaser pursuant to this REPA, such instructions to be in a form reasonably satisfactory to Purchaser. Security held pursuant to Section 11.1(C)(2)(ii) shall be subject to the following: (x) include a requirement for immediate notice to Purchaser from Issuer and Seller in the event that the sums held as security in the account or trust do not at any time meet the required level for the Seller Security Fund as set forth in this Section 11.1, (y) funds held in the account may be deposited in a money-market fund, short-term treasury obligations, investment-grade commercial paper and other liquid investment-grade investments with maturities of three months or less, with all investment income thereon to be taxable to, and to accrue for the benefit of, Seller, and (z) after the Commercial Operation Date is achieved, annual account sweeps for recovery of interest earned by the Seller Security Fund shall be allowed by Seller. Seller grants to Purchaser a present and continuing first priority security interest in all Cash which has been transferred to Purchaser or held by Issuer. At such times as the balance of Cash held by Purchaser or by Issuer exceeds the amount of Seller's obligation to provide security hereunder, Purchaser shall remit to Seller on demand any excess in the account above Seller's obligations.

[redacted]

(D) If the Issuer of the Seller Security Fund no longer satisfies the requirements of Section 11.1(C), Seller shall provide replacement security satisfying the requirements of Section 11.1(C) no later than fifteen (15) Days after receiving notice from Purchaser that such conversion of the Seller Security Fund instrument is required. Upon receipt of such replacement security, Purchaser shall promptly return to Seller of any of Seller Security Fund being replaced then held by Purchaser and the effectiveness of any such replacement security shall be conditioned upon such prompt return to Seller thereof. Seller may object to Purchaser's request for replacement security by delivering written notice to Purchaser within five (5) Business Days of receipt of Purchaser's written request for such replacement security, and in such event the dispute resolution procedures contained in Exhibit L shall apply.

(E) Promptly following the end of the Term and the completion of all of Seller's obligations under this REPA, Purchaser shall release the Seller Security Fund (including any accumulated interest, if applicable) to Seller.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ARTICLE 12
DEFAULT AND REMEDIES

12.1 Events of Default. Any of the following shall constitute an "Event of Default":

(A) A failure by a Party to pay any amount due hereunder, where such failure is not cured within [redacted] after receipt of written notice of such failure;

(B) Either Party (or any Person providing credit support hereunder on behalf of such Party) has (a) commenced a voluntary case under any bankruptcy law, applied for or consented to the appointment of, or the taking of possession by, a receiver, trustee, assignee, custodian or liquidator of all or a substantial part of its assets, (b) failed, or admitted in writing its inability generally, to pay its debts as such debts become due, (c) made a general assignment for the benefit of creditors (except for an assignment to the Facility Debt Representative as security under the Financing Documents as permitted by this REPA), (d) been adjudicated bankrupt or has filed a petition or an answer seeking an arrangement with creditors, (e) taken advantage of any insolvency law or shall have submitted an answer admitting the material allegations of a petition in bankruptcy or insolvency proceeding, (f) become subject to an order, judgment or decree for relief, entered in an involuntary case, without the application, approval or consent of such Party by any court of competent jurisdiction appointing a receiver, trustee, assignee, custodian or liquidator, for a substantial part of any of its assets and such order, judgment or decree shall continue unstayed and in effect for any period of [redacted] (g) filed a voluntary petition in bankruptcy, (h) failed to remove an involuntary petition in bankruptcy filed against it within [redacted] of the filing thereof, or (i) become subject to an order for relief under the provisions of the United States Bankruptcy Act, 11 U.S.C. § 301;

(C) If Purchaser fails to provide the Purchaser Security Fund *pursuant to Section* 11.2, *or replacement or substitute* Purchaser Security Fund pursuant to Section 11.2, when required, or if Seller fails to provide the Seller Security Fund pursuant to Section 11.1, or replacement or substitute Seller Security Fund pursuant to Section 11.1, when required, and if the Party required to deliver such security fails to do so within five (5) calendar Days after receipt of written notice and demand therefor by the other Party, such failure shall constitute an Event of Default by the Party required to provide such security; or

(D) Any other breach of a material obligation under this REPA, other than as set forth in Section 12.1(A), (B), (C) and (E), if such default has not been cured by the defaulting Party within [redacted] after receiving written notice from the non-defaulting Party setting forth, in reasonable detail, the nature of such default and its impact on the non-defaulting Party; *provided, however,* that, in the case of any such default that is not reasonably capable of being cured within [redacted] period, the defaulting Party shall have additional time as necessary, not to exceed [redacted], to cure the default if it commences to cure the default within such [redacted] period and it diligently and continuously pursues such cure.

(E) Seller's failure to meet the Commercial Operation Milestone by the Delay Damages Commencement Date, where such failure is not cured within [redacted] after the date of written notice of such failure from Purchaser to Seller and the Facility Debt Representative as provided for in Section 13.1; provided, however, that Seller shall have an additional [redacted] period (together with the initial [redacted] period provided for above, a total of [redacted]) to achieve the Commercial Operation Date (and for such failure to constitute an Event of Default), provided that, on or before the expiration of the initial [redacted] period, an independent engineer, mutually agreed to by the Parties, retained by Purchaser and paid for by Seller, provides a written opinion to Purchaser stating that Seller's plan for achieving the Commercial Operation Date is reasonably achievable within such additional [redacted] period. The cure periods provided for in this Section 12.1(E) shall not in any manner reduce, increase or otherwise modify Seller's obligation to pay Delay Damages under Section 4.1, which Delay Damages shall continue accruing and shall expire as provided for in Section 4.1, notwithstanding the cure periods provided for in this Section 12.1(E).

[redacted]

[redacted]

12.2 Facility Lenders' Right to Cure Default of Seller.

Notwithstanding the foregoing provisions of Section 12.1, in the case of an Event of Default by Seller, Purchaser shall provide the Facility Debt Representative (if any) with notice of such Event of Default and the Facility Debt Representative shall have the right (but not the obligation) either to cure the Event of Default on behalf of Seller, or, upon payment to Purchaser of amounts due from Seller but not paid by Seller, to assume, or cause its designee or a lessee or purchaser of the Facility to assume, all of the rights and obligations of Seller under this REPA arising after the date of such assumption as more fully described in Section 19.2.

12.3 Non-Defaulting Party Rights. Upon the occurrence of an Event of Default by a Party, the non-defaulting Party shall have the following rights:

(A) To terminate this REPA pursuant to Section 12.5(A);

(B) To suspend performance of its obligations and duties hereunder immediately upon delivering written notice to the defaulting Party of its intent to exercise its suspension rights; and

(C) To pursue any other remedy given under this REPA or now or hereafter existing at law or in equity or otherwise.

12.4 Damages Prior to Termination.

[redacted] Each Party shall have the right to collect damages from the other Party arising from its breach of this REPA. Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to collect damages accruing prior to the termination of this REPA from the defaulting Party as set forth below, and the payment of any such damages accruing prior to the cure of an Event of Default shall constitute a part of the cure. For all Events of Default (other than Seller's failure to meet the Commercial Operation Milestone, for which Purchaser's sole and exclusive remedy shall be to collect Delay Damages pursuant to Section 4.1 and Seller's failure to achieve the Guaranteed Availability, for which Purchaser's sole and exclusive remedy shall be to collect Shortfall Liquidated Damages pursuant to Section 7.2), the non-defaulting Party shall be entitled to receive from the defaulting Party its damages resulting from such Event of Default. [redacted]

[redacted]

[redacted]

12.5 Termination.

(A) Upon the occurrence of an Event of Default which has not been cured within the applicable cure period, the non-defaulting Party shall have the right to declare a date, which date shall be no less than [redacted] and no more than [redacted] after the expiration of all applicable cure periods with respect to the Event of Default, upon which this REPA shall terminate. Neither Party shall have the right to terminate this REPA except as provided for upon the occurrence of an Event of Default as described above or as otherwise may be explicitly provided for in this REPA. Upon the termination of this REPA under this Section 12.5, the non-defaulting Party shall be entitled to receive from the defaulting Party, all of the actual damages incurred by the non-defaulting Party in connection with such termination in accordance with Section 12.4. Such actual damages shall be calculated for the remainder of the Term (assuming the Term had continued without early termination) on a net present value basis in a commercially reasonable manner.

12.6 Specific Performance.

Each Party shall be entitled to seek a decree compelling specific performance with respect to, and shall be entitled, without the necessity of filing any bond, to seek the restraint by injunction of, any actual or threatened breach of any material obligation of the other Party under this REPA. The Parties in any action for specific performance or restraint by injunction agree that they shall each request that all expenses incurred in such proceeding, including, but not limited to, reasonable counsel fees, be apportioned in the final decision based upon the respective merits of the positions of the Parties.

12.7 Remedies Cumulative.

Subject to the exclusivity of Delay Damages provided in Section 4.1 and Shortfall Liquidated Damages provided in Section 7.2, the limitations on damages set forth in Section 12.8 and other limitations specified in this REPA, each right or remedy of the Parties provided for in this REPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this REPA, and the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.8 Waiver and Exclusion of Other Damages.

The Parties confirm that the express remedies and measures of damages provided in this REPA satisfy the essential purposes hereof. If no remedy or measure of damages is expressly herein provided, the obligor's liability shall be limited to direct, actual damages only. EXCEPT AS MAY BE INCLUDED IN ANY CALCULATION OF LIQUIDATED DAMAGES, TOTAL REPLACEMENT ENERGY COSTS OR RESALE COSTS, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES BY STATUTE, IN TORT OR CONTRACT (EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN); PROVIDED, THAT IF EITHER PARTY IS HELD LIABLE TO A THIRD PARTY FOR SUCH DAMAGES AND THE PARTY HELD LIABLE FOR SUCH DAMAGES IS ENTITLED TO INDEMNIFICATION THEREFORE FROM THE OTHER PARTY HERETO, THE INDEMNIFYING PARTY SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE THE INDEMNIFIED PARTY FOR, SUCH DAMAGES; PROVIDED, FURTHER THAT LOSS OF BENEFICIAL ENVIRONMENTAL INTERESTS SHALL NOT BE CONSIDERED CONSEQUENTIAL DAMAGES. To the extent any damages required to be paid hereunder are liquidated, the Parties acknowledge that the damages are difficult or impossible to determine, that otherwise obtaining an adequate remedy is inconvenient, and that the liquidated damages constitute a reasonable approximation of the harm or loss.

12.9 Payment of Damages.

Without limiting any other provisions of this Article 12 and at any time before or after termination of this REPA, the non-defaulting Party may send the other Party an invoice for such damages (including, if applicable, Delay Damages) or other amounts as are due to the non-defaulting Party at such time from the defaulting Party under this REPA and such invoice shall be payable in the manner, and in accordance with the applicable provisions, set forth in Article 9, including the provision for late payment charges. In the case of damages owed by Seller to Purchaser, Purchaser may, subject to the provisions of Section 11.1, withdraw funds from the Seller Security Fund, as needed to provide payment for such invoice if the invoice is not paid by Seller on or before the [redacted] following the invoice due date. [redacted]

12.10 Duty to Mitigate.

Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of the REPA.

ARTICLE 13
CONTRACT ADMINISTRATION AND NOTICES

13.1 Notices in Writing.

Notices required by this REPA shall be addressed to the other Party, including the other Party's representative on the Contract Administration Committee, at the addresses noted in Exhibit D as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this REPA to be given by one Party to the other Party shall be in writing. It shall either be hand delivered or mailed, postage prepaid, to the representative of said other Party. If mailed, the notice, request, consent or other communication shall be simultaneously sent by facsimile or other electronic means. Any such notice, request, consent, or other communication shall be deemed to have been received by the Close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close in which case it shall be deemed received at the close of the next Business Day). Real-time or routine communications concerning Facility operations shall be exempt from this Section.

13.2 Representative for Notices.

Each Party shall maintain a designated representative to receive notices. Such representative may, at the option of each Party, be the same person as that Party's representative or alternate representative on the Contract Administration Committee, or a different person. Either Party may, by written notice to the other Party, change the representative or the address to which such notices and communications are to be sent.

13.3 Authority of Representatives.

The Parties' representatives designated above shall have authority to act for its respective principals in all technical matters relating to performance of this REPA and to attempt to resolve disputes or potential disputes. However, they, in their capacity as representatives, shall not have the authority to amend or modify any provision of this REPA.

13.4 Operating Records.

Seller and Purchaser shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this REPA, including such records as may be required by state or federal regulatory authorities and the Transmission Operator in the prescribed format.

13.5 Operating Log.

Seller shall maintain an accurate and up-to-date operating log, in electronic format, at the Facility with records of production for each Clock Hour; changes in operating status; Scheduled Outages/Deratings and Forced Outages for the purposes of proper administration of this REPA, including such records as may be required by state or federal regulatory authorities and the Transmission Operator in the prescribed format.

13.6 Billing and Payment Records.

To facilitate payment and verification, Seller and Purchaser shall keep all books and records necessary for billing and payments in accordance with the provisions of Article 9 and grant the other Party reasonable access to those records. All records of Seller pertaining to the operation of a Facility shall be maintained on the premises of the Facility. For audit and verification purposes, Seller will grant Purchaser read-only access to the PJM eSuite accounts for the node associated with the PJM charges and credits for the Renewable Energy Products from Purchaser's Contract Capacity Share of the Facility Capacity.

13.7 Examination of Records.

Seller and Purchaser may examine the financial and Operating Records and data kept by the other Party relating to transactions under and administration of this REPA, at any time during the period the records are required to be maintained, upon request and during normal business hours.

13.8 Exhibits.

Either Party may change the information for their notice addresses in Exhibit D at any time upon written notice to but without the approval of the other Party. Exhibit C may only be changed in accordance with Section 20.4. Exhibit E may be changed in accordance with Section 16.2(B). All other Exhibits may only be modified by the mutual agreement of Seller and Purchaser.

13.9 Dispute Resolution.

(A) Except as otherwise expressly provided in this REPA, in the event of any dispute, controversy or claim arising under this REPA (a "Dispute"), within ten (10) Days following the delivered date of a written request by either Party (a "Dispute Notice"), (i) each Party shall appoint a representative (individually, a "Party Representative", together, the "Parties' Representatives"), and (ii) the Parties' Representatives shall meet, negotiate and attempt in good faith to resolve the Dispute quickly, informally and inexpensively. In the event the Parties' Representatives cannot resolve the Dispute within thirty (30) Days after commencement of negotiations, within ten (10) Days following any request by either Party at any time thereafter, each Party Representative (I) shall independently prepare a written summary of the Dispute describing the issues and claims, (II) shall exchange its summary with the summary of the Dispute prepared by the other Party Representative, and (III) shall submit a copy of both summaries to a senior officer of the Party Representative's Party with authority to irrevocably bind the Party to a resolution of the Dispute. Within ten (10) Business Days after receipt of the Dispute summaries, the senior officers for both Parties shall negotiate in good faith to resolve the Dispute. If the Parties are unable to resolve the

Dispute within fourteen (14) Days following receipt of the Dispute summaries by the senior officers, either Party may seek available legal remedies.

(B) Seller and Purchaser each hereby knowingly, voluntarily and intentionally waive any rights they may have to a trial by jury in respect of any litigation based hereon, or arising out of, under, or in connection with, this REPA or any course of conduct, course of dealing, statements (whether oral or written) or actions of Seller and Purchaser related hereto and expressly agree to have any disputes arising under or in connection with this REPA be adjudicated by a judge of the court having jurisdiction without a jury.

ARTICLE 14
FORCE MAJEURE

14.1 Definition of Force Majeure.

(A) The term "Force Majeure", as used in this REPA, means any event which wholly or partly prevents or delays the performance of any obligation arising under this REPA, but only if and to the extent (i) such event is not within the reasonable control, directly or indirectly, of the Party affected, (ii) such event, despite the exercise of reasonable diligence, cannot be prevented, avoided or overcome by such Party, (iii) the Party affected has taken all reasonable precautions and measures pursuant to Good Utility Practices in order to avoid the effect of such event on such Party's ability to perform its obligations under this REPA and to mitigate the consequences thereof, and (iv) such event is not the direct or indirect result of a Party's negligence or the failure of such Party to perform any of its obligations under this REPA or to comply with Applicable Law. A Force Majeure Event may include, but is not limited to, any of the following (but only if and to the extent such event meets the requirements of (i) – (iv) above): (a) acts of God or the public enemy, war, whether declared or not, blockade, insurrection, riot, civil disturbance, public disorders, rebellion, violent demonstrations, revolution, sabotage or terrorist action; (b) any effect of unusual natural elements, including fire, subsidence, earthquakes, floods, lightning, tornadoes, unusually severe storms, or similar cataclysmic occurrence or other unusual natural calamities; (c) environmental and other contamination at or affecting the Facility; (d) explosion, accident or epidemic; (e) governmental action or inaction; (f) general strikes, lockouts or other collective or industrial action by workers or employees, or other labor difficulties; (g) the unavailability of labor, fuel, power or raw materials, the breakdown of the Facility or other plant breakdown or equipment failure, and any event affecting the ability of any supplier (including under any engineering, procurement or construction agreement for the Facility) to the Facility to fulfill its obligations to Seller and the Facility so long as, in each case, the cause thereof otherwise would qualify as a Force Majeure; (h) accidents of navigation or breakdown or injury of vessels, accidents to harbors, docks, canals or other assistances to or adjuncts of shipping or navigation, or quarantine; (i) nuclear emergency, radioactive contamination or ionizing radiation or the release of any hazardous waste or materials; and (j) air crash, shipwreck, train wrecks or other failures or delays of transportation; *provided*, *however*, that the lack of money, changes in market conditions, and those items expressly excluded in Section 14.1(B), below, shall not constitute a Force Majeure.

(B) The term Force Majeure does not include the inability or failure of Purchaser to obtain transmission service and the unavailability, interruption or curtailment of transmission service, all of which are expressly addressed under other provisions of this REPA.

14.2 Applicability of Force Majeure.

(A) Other than as set forth in Section 14.3, neither Party shall be responsible or liable for any delay or failure in its performance under this REPA, nor shall any delay, failure, or other occurrence or event become an Event of Default, to the extent such delay, failure, occurrence or event is substantially caused by conditions or events of Force Majeure, provided that:

(1) the non-performing Party gives the other Party prompt written notice describing the particulars of the occurrence of the Force Majeure;

(2) the suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure;

(3) the non-performing Party proceeds with reasonable diligence to remedy its inability to perform and provides weekly progress reports to the other Party describing actions taken to end the Force Majeure; and

(4) when the non-performing Party is able to resume performance of its obligations under this REPA, that Party shall give the other Party prompt written notice to that effect.

(B) Except as otherwise expressly provided for in this REPA, the existence of a condition or event of Force Majeure shall not relieve the Parties of their obligations under this REPA (including payment obligations) to the extent that performance of such obligations is not precluded by the condition or event of Force Majeure.

14.3 Limitations on Effect of Force Majeure.

In no event will any delay or failure of performance caused by any conditions or events of Force Majeure extend this REPA beyond its stated Term. In the event that any delay or failure of performance caused by conditions or events of Force Majeure prevents the performance of a Party's obligations hereunder in any material respect and continues for an uninterrupted period of [redacted] from its occurrence or inception, as noticed pursuant to Section 14.2(A), the Party not claiming Force Majeure may, at any time following the end of such [redacted] period, terminate this REPA upon written notice to the affected Party, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination. The Party not claiming Force Majeure may, but shall not be obligated to, extend such [redacted] period, for such additional time as it, at its sole discretion, deems appropriate, if the affected Party is exercising due diligence in its efforts to cure the conditions or events of Force Majeure.

ARTICLE 15
REPRESENTATIONS, WARRANTIES AND COVENANTS

15.1 Seller's Representations, Warranties and Covenants.

Seller hereby represents and warrants as follows as of the date hereof:

(A) Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the State of Delaware. Seller is qualified to do business in each other jurisdiction where the failure to so qualify would have a material adverse effect on the business or financial condition of Seller; and Seller has all requisite power and authority to conduct its business, to own its assets, and to execute, deliver, and perform its obligations under this REPA.

(B) The execution, delivery, and performance of its obligations under this REPA by Seller have been duly authorized by all necessary limited liability company action, and do not and will not

(1) violate any provision of law, rule, regulation, order, writ, judgment, injunction, decree, determination, or award currently in effect having applicability to Seller or violate any provision in any formation documents of Seller, the violation of which could have a material adverse effect on the ability of Seller to perform its obligations under this REPA;

(2) result in a breach or constitute a default under Seller's formation documents or bylaws, or under any agreement relating to the management or affairs of Seller or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Seller is a party or by which Seller or its assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Seller to perform its obligations under this REPA; or

(3) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this REPA) upon or with respect to any of the assets of Seller now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Seller to perform its obligations under this REPA.

(C) This REPA is a valid and binding obligation of Seller.

(D) The execution and performance of this REPA will not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party or any judgment, order, statute, or regulation that is applicable to Seller or the Facility.

(E) To the knowledge of Seller, all permits, consents, approvals, licenses, authorizations, or other action required by any Governmental Authority to authorize Seller's execution, delivery and performance of this REPA have been duly obtained and are in full force and effect.

15.2 Purchaser's Representations, Warranties and Covenants.

Purchaser hereby represents and warrants as follows as of the date hereof:

(A) Purchaser is a corporation duly organized, validly existing and in good standing under the laws of the State of Kentucky and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of Purchaser; and Purchaser has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this REPA.

(B) The execution, delivery, and performance of its obligations under this REPA by Purchaser have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval of Purchaser's Board of Directors, or shareholders, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Seller upon its request);

(2) violate any provision of law, rule, regulation, order, writ, judgment, injunction, decree, determination, or award currently in effect having applicability to Purchaser or violate any provision in any corporate documents of Purchaser, the violation of which could have a material adverse effect on the ability of Purchaser to perform its obligations under this REPA;

(3) result in a breach or constitute a default under Purchaser's corporate charter or bylaws, or under any agreement relating to the management or affairs of Purchaser, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Purchaser is a party or by which Purchaser or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Purchaser to perform its obligations under this REPA; or

(4) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this REPA) upon or with respect to any of the assets or properties of Purchaser now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Purchaser to perform its obligations under this REPA.

(C) This REPA is a valid and binding obligation of Purchaser.

(D) The execution and performance of this REPA will not conflict with or constitute a breach or default under any contract or agreement of any kind to which Purchaser is a party or any judgment, order, statute, or regulation that is applicable to Purchaser.

[redacted]

ARTICLE 16
INSURANCE

16.1 <u>Evidence of Insurance</u>.

Within ten (10) days following execution of this REPA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within thirty (30) days thereafter, Seller shall provide Purchaser insurance certificates executed by each insurer or by an authorized representative of each insurer evidencing that insurance coverages for the Facility are in compliance with the specifications for insurance coverage set forth in Exhibit E to this REPA. Such certificates shall (a) name Purchaser as an additional insured on all policies required (except worker's compensation and employer's liability); (b) [redacted] (c) provide a waiver of any rights of subrogation against Purchaser, its Affiliates and their officers, directors, agents, subcontractors, and employees; and (d) indicate that the Commercial General Liability policy has been endorsed as described above. All policies shall be procured and maintained through insurance companies licensed to do business as required by applicable law in the state where the Facility located and is rated [redacted]. All policies shall be primary as respects any claims, losses, damages, expenses or liabilities arising out of this REPA and insured hereunder, and any insurance carried by Purchaser shall be excess and noncontributing with insurance afforded by these policies. Seller's liability under this REPA is not limited to the amount of insurance coverage required herein.

16.2 <u>Term and Modification of Insurance</u>.

(A) All insurance required under this REPA shall cover occurrences during the Term and for a period of [redacted]. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the date of this REPA and such insurance shall be maintained by Seller, with a retroactive date not later than the retroactive date required above, for a minimum of [redacted]

(B) If any insurance required to be maintained by Seller hereunder ceases to be reasonably available and commercially feasible in the commercial insurance market, Seller shall provide written notice to Purchaser, accompanied by a certificate from an independent insurance advisor of recognized national standing, certifying that such insurance is not reasonably available and commercially feasible in the commercial insurance market for electric generating plants of similar type, geographic location and design. Upon receipt of such notice, Purchaser shall not unreasonably withhold its consent to modify or waive such requirement.

ARTICLE 17
INDEMNITY

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ARTICLE 18
LEGAL AND REGULATORY COMPLIANCE

(A) Each Party shall at all times comply with all laws, ordinances, rules, and regulations applicable to it, except for any non-compliance which, individually or in the aggregate, could not reasonably be expected to have a material effect on the business or financial condition of the Party or its ability to fulfill its commitments hereunder. As applicable, each Party shall give all required notices, shall procure and maintain all governmental permits, licenses, and inspections necessary for performance of this REPA, and shall pay its respective charges and fees in connection therewith.

(B) Each Party shall cooperate with the other Party in providing such information as may be reasonably requested, to the extent permitted by applicable law and subject to such confidentiality and use limitations as the providing Party may reasonably require, to the extent that the requesting Party requires the same in order to fulfill any regulatory reporting requirements, or to assist the requesting Party in litigation, including administrative proceedings before utility regulatory commissions.

(C) Upon permanent cessation of generation of Renewable Energy from the Facility, Seller shall decommission the Facility, remove the Facility and remediate the Site as, if and when required by law.

ARTICLE 19
ASSIGNMENT, SUBCONTRACTING, AND FINANCING

[redacted]

[redacted]

[redacted]

[redacted]

19.2 Accommodation of Facility Debt Representative.

Purchaser shall make reasonable efforts to provide such consents to assignments, certifications, representations, information or other documents as may be reasonably requested by Seller or the Facility Debt Representative in connection with the financing of the Facility, which shall include providing Facility Debt Representative with the protections contained in the form of Consent and Assignment attached hereto as Exhibit M (the "Consent and Agreement") and providing the Facility Debt Representative with an opinion of in-house counsel limited to enforceability, non-contravention and corporate housekeeping matters; provided, that in responding to any such request, Purchaser shall have no obligation to provide any consent or opinion, or enter into any agreement (other than as provided in the Consent and Assignment), that materially adversely affects any of Purchaser's rights, benefits, risks and/or obligations under this REPA. Seller shall reimburse, or shall cause the Facility Debt Representative to reimburse, Purchaser for the incremental direct expenses (including the reasonable fees and expenses of counsel) incurred by Purchaser in the preparation, negotiation, execution and/or delivery of any documents requested by Seller or the Facility Debt Representative, and provided by Purchaser, pursuant to this Section 19.2.

19.3 Notice of Facility Debt Representative Action.

Within ten (10) Days following Seller's receipt of each written notice from the Facility Debt Representative of default, or Facility Debt Representative's intent to exercise any remedies, under the Financing Documents, Seller shall deliver a copy of such notice to Purchaser.

19.4 Transfer Without Consent is Null and Void.

Any sale, transfer, or assignment of this REPA made without fulfilling the requirements of the REPA shall be null and void and shall constitute an Event of Default pursuant to Article 12.

19.5 Subcontracting.

Seller may subcontract its duties or obligations under this REPA without the prior written consent of Purchaser, provided, that no such subcontract shall relieve Seller of any of its duties or obligations hereunder.

ARTICLE 20
MISCELLANEOUS

20.1 Waiver.

Subject to the provisions of Section 13.9(B), the failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this REPA, or to take advantage of any of its rights there under, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

20.2 Taxes. Seller shall pay or cause to be paid (and shall indemnify and hold Purchaser harmless from and against) all sales, use, excise, ad valorem, transfer and other similar taxes, but excluding in all events taxes based on or measured by net income, that are imposed by any taxing authority (individually, a "Tax" and collectively, "Taxes") on or with respect to the sale of Energy incurred prior to the delivery of the Energy to the Point of Delivery. Purchaser shall pay or cause to be paid (and shall indemnify and hold Seller harmless from and against) all Taxes on or with respect to the sale of Energy incurred upon and after the delivery of Energy to the Point of Delivery and all Taxes associated with the Renewable Energy Credits. If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, the responsible Party shall promptly reimburse the other for such Taxes. Both Parties shall use reasonable efforts to administer this REPA and implement the provisions in accordance with their intent to minimize Taxes for which each is responsible hereunder. In the event any of the sales of Energy or Renewable Energy Credits hereunder are exempt or excluded from any particular Tax(es) payable by Purchaser, Purchaser shall provide Seller with all necessary documentation within thirty (30) days after the execution of this REPA to evidence such exemption or exclusion (or, with regard to any such Tax(es) enacted after the Effective Date, Purchaser shall provide Seller with such documentation before the date on which the enactment requires the delivery of documentation to Seller in order to effect an exclusion or exemption from such Tax(es)). In the event Purchaser does not provide such documentation, then Purchaser shall indemnify, defend and hold Seller harmless from any liability with respect to Tax(es) to which Purchaser is exempt or excluded.

20.3 Fines and Penalties.

(A) Seller shall pay when due all fees, fines, penalties or costs to the extent incurred by Seller or its agents, employees or contractors for noncompliance by Seller, its employees, or subcontractors with any provision of this REPA, or any contractual obligation, permit or requirements of law except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by Seller and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, penalties, or costs are claimed or assessed against either Party by any Governmental Authority or PJM due to noncompliance by the other Party with this REPA, any requirements of law with which compliance is required by this REPA, any permit or contractual obligation, or, if the work of the other Party or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority or PJM due to the other Party's noncompliance with any requirements of law with which compliance is required by this REPA, permit, or contractual obligation, penalized Party shall indemnify and hold other Party harmless against any and all reasonable losses, liabilities, damages, and claims suffered or incurred by other Party, including claims for indemnity or contribution made by third parties against other Party, except to the extent other Party recovers any such losses, liabilities or damages through other provisions of this REPA.

20.4 Rate Changes.

The terms and conditions and the rates for service specified in this REPA shall remain in effect for the term of the transaction described herein. Absent the Parties' written agreement, this REPA shall not be subject to change by application of either Party pursuant to Section 205 or 206 of the Federal Power Act.

Absent the agreement of all parties to the proposed change, the standard of review for changes to this REPA whether proposed by a Party, a non-party, or the Federal Energy Regulatory Commission acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipe Line v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra doctrine"), or such other standard of review permissible to preserve the intent of the parties pursuant to this Section to uphold the sanctity of contracts without modification.

20.5 Disclaimer of Third Party Beneficiary Rights.

Nothing in this REPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any person not a party to this REPA.

20.6 Relationship of the Parties.

(A) This REPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of persons to perform such services, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the persons employed by Seller shall be considered employees of Purchaser for any purpose; nor shall Seller represent to any person that he or she is or shall become a Purchaser employee.

20.7 Equal Employment Opportunity Compliance Certification.

Seller acknowledges that as a government contractor Purchaser is subject to various federal laws, executive orders, and regulations regarding equal employment opportunity and affirmative action. These laws may also be applicable to Seller as a subcontractor to Purchaser. Seller shall comply with all applicable equal opportunity and affirmative action federal laws, executive orders, and regulations, including, if applicable, 41 C.F.R. §60-1.4(a)(1-7).

20.8 Survival of Obligations.

Cancellation, expiration, or earlier termination of this REPA shall not relieve the Parties of obligations that by their nature should survive such cancellation, expiration, or termination, prior to the term of the applicable statute of limitations, including warranties, remedies, or indemnities, which obligations shall survive for the period of the applicable statute(s) of limitation.

20.9 Severability.

In the event any of the terms, covenants, or conditions of this REPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of the REPA and their application not adversely affected thereby shall remain in force and effect.

20.10 Complete Agreement; Amendments.

The terms and provisions contained in this REPA constitute the entire agreement between Purchaser and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Purchaser and Seller with respect to the sale of Renewable Energy Products from and associated with the Facility. This REPA may be amended, changed, modified, or altered, provided that such amendment, change, modification, or alteration shall be in writing and signed by both Parties hereto.

20.11 Binding Effect.

This REPA, as it may be amended from time to time pursuant to this Article, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

20.12 Headings.

Captions and headings used in this REPA are for ease of reference only and do not constitute a part of this REPA.

20.13 Counterparts.

This REPA may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

20.14 Governing Law; Consent to Jurisdiction; Waiver of Jury Trial.

The interpretation and performance of this REPA and each of its provisions shall be governed and construed in accordance with the laws of the State of New York, without regard to its conflicts of laws provisions. [redacted]

[redacted]

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20.15 Confidentiality.

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IN WITNESS WHEREOF, the Parties have executed this REPA.

Seller:

FPL ENERGY ILLINOIS WIND, LLC

By: ______________________________

Purchaser:

KENTUCKY POWER COMPANY

By: ______________________________

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EXHIBIT B

FACILITY DESCRIPTION AND SITE MAPS

This Exhibit B is conceptual. A final "as-built" Exhibit B will be completed and attached to this REPA in place hereof after the Facility is completed.

Seller intends to build, own and operate a wind project with a total capacity not to exceed approximately 217.5 MW. The Facility will be located in Lee and Dekalb counties, Illinois and will be interconnected to the 138kV Steward to Waterman transmission line. The Facility will generate electrical power to be sold in the wholesale market.

As presently planned, the Facility will consist of:

- One hundred forty-five (145) GE 1.5 XLE Wind Turbines on 80-meter tubular steel towers for the Facility (each individual Wind Turbine having a nameplate capacity rating of approximately 1500 kW).
- A network of several miles of low profile, gravel field roads providing access to Wind Turbines
- Electrical transformation equipment located at the Facility.
- An underground and aboveground fiber-optic data collection system.
- Maintenance and field office

EXHIBIT C

CONTRACT RATE
($ Per MWh)

The Contract Rate for Monday through Friday excluding NERC Holidays shall be the amount set forth in the table below for the applicable hour:

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Beginning January 1, 2012, and on each January 1 thereafter for the remainder of the Term, rates will be increased by 2.25% over the rates for the previous calendar year.

The Contract Rate for Saturdays, Sundays, and all NERC Holidays shall be the amount set forth in the table below for the applicable hour:

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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EXHIBIT D

NOTICE ADDRESSES

Page 1 of 1

Purchaser	Seller
Notices: Kentucky Power Company C/O American Electric Power Service Corporation 155 West Nationwide Boulevard Columbus, OH 43215 Attn: Contract Administration Fax:(614) 583-1606 **with copies to:** American Electric Power Service Corporation 155 West Nationwide Boulevard Columbus, OH 43215 Attn: Director, Credit Risk Department Fax: (614) 583-1604 **and** Attn: Chief Counsel, CO&L American Electric Power Service Corporation 155 West Nationwide Boulevard Columbus, OH 43215 Attn: Chief Counsel Fax: (614) 583-1603	**Notices:** FPL Energy Illinois Wind, LLC c/o NextEra Energy, LLC 700 Universe Boulevard Juno Beach, FL 33408 Attn: Vice President, Renewables Business Management **with copies to:** FPL Energy Illinois Wind, LLC c/o NextEra Energy, LLC 700 Universe Boulevard Juno Beach, FL 33408 Attn: General Counsel **and** FPL Group Capital Inc. 700 Universe Boulevard Juno Beach, FL 33408 Attn: Treasurer
Contract Administration Committee Representative: Jay Godfrey (614) 583-6162 **jfgodfrey@aep.com** **Alternate:** To be designated in writing by Purchaser at or prior to the first meeting of the Contract Administration Committee	**Contract Administration Committee Representative:** FPL Energy Illinois Wind, LLC c/o NextEra Energy, LLC 700 Universe Boulevard Juno Beach, FL 33408 Attn: Vice President, Renewables Business Management

EXHIBIT E

INSURANCE COVERAGE

SPECIFICATION OF INSURANCE COVERAGE

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EXHIBIT F

[INTENTIONALLY DELETED]

EXHIBIT G

POINT OF DELIVERY

This Exhibit G is conceptual. A final "as-built" Exhibit G will be completed and attached to this REPA in place hereof after the Facility is completed.

Conceptual One-Line Diagram
Lee/Dekalb Wind Farm
(Not to be used for actual Design or Construction)

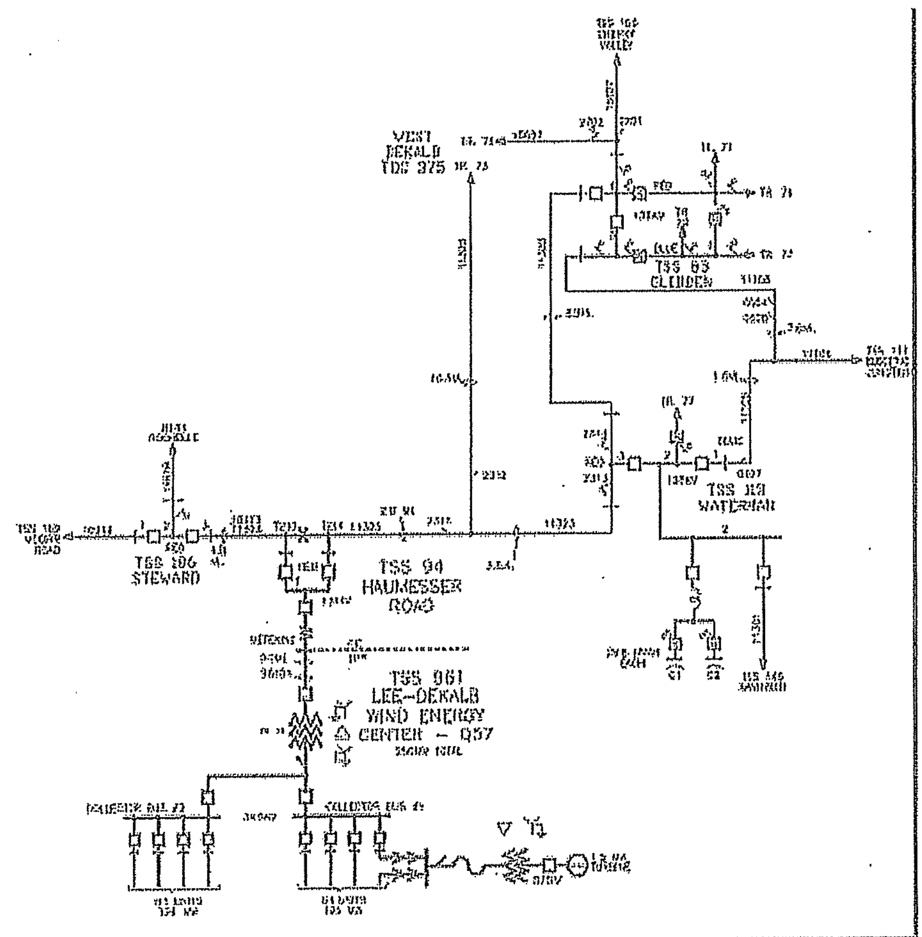

Figure 1. Interconnection Single Line Diagram

EXHIBIT H

Requirements Specification
Real Time Data Requirements for Wind Farms

American Electric Power
Requirements Specification
Real Time Data Requirements for Wind Farms

Version 1.5

1. Purpose

The purpose for real time data from the Wind Farm SCADA system to AEP's Generation Control System is to enable AEP to utilize detailed on-site project information, such as individual measured turbine wind speeds and production, in order to produce the most accurate generation forecast for the wind farm and to optimize integration of the wind generation into the electric power grid.

2. Required Wind Farm SCADA Information

Data must be collected by the wind farm SCADA system and transmitted to AEP at a minimum refresh rate of once every 30 seconds. Minimum required SCADA information includes the following:

i. Total wind farm output (instantaneous MW / MVAR and pulse accumulator MWH / MVARH), which should come from the same metering that the interconnect agreement stipulates
ii. Meteorological Tower Data from at least 2 met towers:
   a) Temperature
   b) Pressure
   c) Relative Humidity
   d) Wind Speed
   e) Wind Direction
iii. Per Turbine Information:
   a) Output (in kW and kVAR)
   b) Wind Speed (in m/s or mph, with at least one decimal point resolution)
   c) Wind Direction (in degrees)
      1. Alternatively, turbine yaw (in degrees) and wind deviation (in degrees)
   d) Status
      1. Ready to generate, but wind speed too low
      2. Ready to generate, but wind speed too high
      3. Online and generating
      4. Offline due to scheduled outage, or unplanned outage

3. Data Communication to AEP

Data communication of the required wind farm SCADA information to AEP must include one or more communication paths to AEP's information systems: 1) to an AEP RTU, AEP PC or a remote AEP data collection system (which could include satellite), for metering data (item 2-i above) and 2) with a TCP/IP network connection to a PC, which will be owned and maintained by AEP and located at the wind farm site, for SCADA information (items 2-ii and 2-iii above). AEP will be responsible for the cost and installation of the telecommunication lines and equipment from the AEP RTU, the AEP PC or the remote data collection system to AEP's information systems. The wind farm owner must be responsible for any telecommunications from the wind farm SCADA to the AEP RTU and AEP PC.

a) Communication to an AEP RTU at the wind farm site (or to a remote AEP data collection system) should be accomplished using an industry standard interface, both in hardware interface and in software protocol, that can be supported by an AEP RTU. At a minimum, AEP RTUs support RS232 hardware, using either Modbus or DNP protocol, although there may be other hardware interfaces (such as Ethernet) and software protocols that can be utilized.

b) Communication to AEP using a PC located at the site and a dedicated TCP/IP network connect should use an industry standard protocol (such as OPC or Modbus TCP, where the AEP PC would be an OPC/Modbus client that collects data from an OPC/Modbus server) to communicate the point data from the wind farm SCADA to the AEP PC.

Seller must provide server rack/UPS and space in facility substation server room for Purchaser's on-site server and other related communications equipment.

4. Point-to-point check out

The SCADA vendor will be required to perform a point-by-point data checkout, verifying that each point is properly transmitted to the AEP RTU and AEP PC. All metering, communications and point-to-point check out must be completed prior to the Commercial Operation Milestone.

Data	Units
Turbine Data **For each turbine (n = 1 to number of turbines at site)**	
Turbine n Nacelle Wind Speed	m/s
Turbine n Nacelle position	deg
Turbine n Wind Deviation	deg
Turbine n Turbine Power	kW
Turbine n BladeAngle 1 - Actual	deg
Turbine n BladeAngle 2 - Actual	deg
Turbine n BladeAngle 3 - Actual	deg
Turbine n Turbine Status	See below for turbine status

Met Data **For each Met Tower (n = 1 to number of Met Towers at site)**	
Met n Wind Speed (multiple points if multiple heights are available)	m/s
Met n Wind Direction	deg
Met n Ambient Temperature	deg C
Met n Barometric Pressure	mB
Met n Humidity	%

Turbine Status	
1. Ready to generate, but wind speed too low	
2. Ready to generate, but wind speed too high	
3. Online and generating	
4. Offline due to scheduled outage, or unplanned outage	

EXHIBIT I

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EXHIBIT K

FORM OF AVAILABILITY NOTICE

Effective Date__________________

Time____________________

HOUR	Capacity	Number of Wind Turbines in Operation
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
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17		
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EXHIBIT L

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EXHIBIT M

FORM OF CONSENT AND AGREEMENT

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2009 1100MW Renewable Request for Proposal (RFP)

Bid Results

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN ELECTRIC RATES OF KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY OF DIANA L. GREGORY

ON BEHALF OF KENTUCKY POWER COMPANY

December 29, 2009

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

CASE NO. 2009-00459

TABLE OF CONTENTS

DIRECT TESTIMONY OF DIANA L. GREGORY
ON BEHALF OF
KENTUCKY POWER COMPANY

I. INTRODUCTION

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

A. My name is Diana L. Gregory. My business address is 700 Morrison Road, Gahanna, Ohio 43230-6642. I am the Director of Transmission Accounting for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. AEP is the parent company of Kentucky Power Company (KPCo or Company).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND.

A. I received a Bachelor of Science in Business Administration degree, majoring in Accounting, in 1994, from Miami University. I was employed by Worthington Cylinders in 1994 as a plant controller. I joined AEPSC in 2000 as a financial coordinator. I briefly worked in human resources before returning to accounting as a Supervisor in Investment accounting and then Manager, Investment Accounting in 2004. In 2007 I became the Manager of East Power Pool Settlements. In this role I had access to information directly related to how PJM bills costs. In 2008, I assumed my current position as the Director of Transmission Accounting.

I am a Certified Public Accountant licensed in Ohio.

Q. WHAT ARE YOUR RESPONSIBILITIES AS THE DIRECTOR OF TRANSMISSION ACCOUNTING?

A. As the Director of Transmission Accounting I am responsible for the accounting for transmission settlements and certain transmission joint ventures.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my direct testimony is to describe the billing and allocation of costs and credits for transmission services provided to AEP by PJM Interconnection L.L.C. (PJM), the regional transmission organization (RTO) of which the Company is a member. The costs and credits are billed according to applicable rates, terms and conditions previously approved by the Federal Energy Regulatory Commission (FERC) under the PJM Open Access Transmission Tariff (PJM OATT). More specifically with respect to the PJM charges and credits, I will describe the billing for and allocation of: (1) FERC- approved Network Integration Transmission Service (NITS) charges; (2) firm and non-firm point-to-point (PTP) transmission revenues; (3) ancillary service charges designed to recover transmission costs (Schedule 1A); (4) PJM transmission enhancement charges for transmission projects approved in the PJM Regional Transmission Expansion Plan (RTEP); (5) PJM administrative charges for operating PJM and for funding various organizations through schedules included in the PJM OATT; (6) RTO formation cost recovery charges and PJM expansion cost recovery charges; and (7) PJM default allocation assessments. These charges and credits are described in greater detail in the direct testimony of Witness Bethel. My testimony will explain, in general, how the aforementioned charges and credits are billed to AEP, assigned between the native load (i.e., Load Serving Entity or LSE) and off-system sales (OSS) related activities and then allocated to the AEP System – East Zone [1] (AEP), including KPCo, using the appropriate allocation basis. I will also explain how the PJM OATT charges and credits (hereinafter referred to as PJM OATT net costs) are recorded in KPCo's general ledger and describe KPCo's proposed deferral accounting for over/under recovery. AEP will need the final order in this proceeding to provide for the future recovery of any PJM OATT net costs in excess of applicable Kentucky transmission revenues.

II. BILLING AND ALLOCATION

Q. WOULD YOU PLEASE DESCRIBE THE INVOICES THAT AEP RECEIVES FROM PJM RELATING TO GENERATION RESOURCES AND LOAD RESPONSIBILITIES?

A. AEP East Zone Operating Companies are represented in the PJM market as a single account for generation resources and load responsibilities. PJM provides AEP invoices with Billing Line items which detail the charges and credits applicable to the PJM Operating Agreement and Open Access Transmission Tariff. PJM does not, however, designate charges and credits between the LSE and OSS; this responsibility belongs to AEPSC and will be discussed later in my direct testimony.

[1] The AEP System - East Zone (AEP) consists of the following operating companies with generation capabilities: Kentucky Power Company serving portions of eastern Kentucky; Indiana Michigan Power Company serving portions of Indiana and Michigan, Columbus Southern Power Company, serving portions of central and southern Ohio; Appalachian Power Company, serving portions of West Virginia and Virginia; and Ohio Power Company serving portions of Ohio. In addition, two operating companies residing in this AEP System – East Zone, Kingsport Power Company (KgP) and Wheeling Power Company (WPCo) represent non-generating affiliates.

Q. WOULD YOU PLEASE GENERALLY DESCRIBE HOW PJM ASSESSES CHARGES AND CREDITS TO AEP?

A. The costs of providing services to PJM market participants are charged according to the FERC approved PJM OATT as discussed by Witness Bethel. PJM applies the tariff rates to the various generation, load, and transmission billing determinants specified in the PJM OATT. Likewise, AEP receives credits in return for services that AEP provides under the PJM OATT and PJM Operating Agreement. As a part of the PJM Settlement Process, PJM charges AEP for services provided, and credits AEP for services provided by AEP on behalf of its retail and wholesale customers.

Q. IF AEP BELIEVES A BILLING ERROR BY PJM MAY HAVE OCCURRED, IS THERE A MEANS BY WHICH AEP MAY CHALLENGE THE PJM BILLED AMOUNT?

A. Yes. In the event of a suspected billing error, AEPSC will contact PJM's market settlement operations group. PJM, after an assessment of the data provided by AEP, will either accept or deny the dispute. If PJM accepts the dispute, PJM will process an adjustment to the bill in the current or subsequent month, depending on the timing of when the bill is published.

AEPSC Commercial Operations (or Power Settlements) group estimates PJM charges and credits concurrently with PJM through their "Shadow Settlement" process to help ensure the accuracy of PJM invoices. The Shadow Settlement estimate uses data supplied by PJM that relates to the charges and credits identified on the PJM invoice.

Q. HOW DOES AEPSC ASSIGN THE CHARGES AND CREDITS BETWEEN NATIVE LOAD AND OSS FROM THE PJM INVOICES?

A. AEPSC uses hourly MWh information from PJM to reconstruct the resources (both generation and purchased energy) used to serve the native load requirements and to fulfill OSS obligations. The reconstruction of the hourly data is completed using AEP's internal Energy Costing and Reporting (ECR) process. The ECR process assigns generation resources and market purchases (resources) with the highest hourly cost to OSS, resulting in the least cost resources serving the native load customers[2]. Based on this reconstruction, PJM administrative charges and default allocation assessments are assigned proportionally, based on Load Ratio Share (LRS), to the LSE and OSS. The LRS is the ratio of native load and OSS load obligations to the total load. The costs assigned to OSS are included in the calculation of OSS margins. OSS margins are discussed in the testimony of Witness Myers. The remaining charges and credits are assigned directly to the LSE.

Q. HOW DOES AEPSC ALLOCATE THE LSE AND OSS CHARGES AND CREDITS FROM THE PJM INVOICES TO KPCo AND THE OTHER AEP SYSTEM-EAST ZONE COMPANIES?

A. Once the PJM charges and credits have been assigned to either the LSE or OSS, they are then allocated to the AEP System – East Zone Operating Companies,

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2 ECR is an internal AEP application used for assigning and reporting the cost and revenues associated with OSS for pool settlements of the Eastern AEP operating companies. ECR calculates costs, demand and energy charges and provides reporting on these results. Using an economic dispatch model, ECR determines the costs associated with OSS on an hourly basis. The ECR process assigns generation and market purchases with the highest price to these off system sales. Once all OSS activity has been covered by the higher cost generation and market purchases, the remaining lower cost resources are assigned to AEP's native load customers.

including KPCo, based on each company's Member Load Ratio (MLR) percentage or transmission pole miles[3]. The MLR allocation methodology is discussed by Witness Wagner.

The charges and credits related to NITS, PTP Transmission Revenues, Transmission owner scheduling, system control and dispatch service (Schedule 1A), PJM Transmission Enhancement charges, PJM administrative charges and default allocation assessments are allocated to the AEP East Zone operating companies based on their respective MLR. Charges related to RTO formation cost recovery and PJM expansion cost recovery are allocated to the operating companies based on each company's transmission pole miles.

Q. WOULD YOU PLEASE DESCRIBE HOW THE PJM OATT CHARGES AND CREDITS ARE RECORDED IN KPCo'S GENERAL LEDGER?

A. Yes. Since the actual PJM invoices are received after AEP's month-end settlement and closing have been completed, an estimate of charges and credits for the current month is recorded, based on information received from PJM. The following month, an adjustment is made to true-up the estimate amount to the actual invoice amount. Both the estimate and the actual settlement are received on a total AEP basis. The amounts recorded to KPCo's general ledger reflect KPCo's allocated share of those settlements. Most of these charges and credits are allocated to KPCo as discussed above.

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3 Transmission pole miles are calculated using the pole miles for each separate AEP system company as the numerator, and the total company pole miles as the denominator. The resulting ratios are applied to the total cost to be allocated based on the formula.

Q. WOULD YOU PLEASE DESCRIBE THE CATEGORIES OF FERC-APPROVED ACCOUNTS IN WHICH THESE CHARGES AND CREDITS ARE RECORDED?

A. A schedule of the charges and credits to be recovered and the accounts to which they are recorded is set forth in Exhibit DLG-1. The majority of the charges and credits are charged 100% to a specific account. The exception to charging or crediting 100% to one account are certain PJM administrative charges, which are charged to Account 561.4, Scheduling, System Control and Dispatching Services, Account 561.8, Reliability Planning and Standards Development Services, and Account 575.7, Market Facilitation, Monitoring and Compliance Services, in accordance with FERC Order 668, but are assigned among these accounts based on instructions from PJM.

III. DEFERRAL ACCOUNTING

Q. WOULD YOU PLEASE DESCRIBE THE TRUE-UP OVER/UNDER RECOVERY DEFERRAL ACCOUNTING FOR THE KENTUCKY TRANSMISSION REVENUES AND ALLOWABLE PJM OATT NET COSTS THROUGH THE KENTUCKY TRANSMISSION ADJUSTMENT TARIFF (T.A.)?

A. When the T.A. is implemented, KPCo will be comparing the sum of the base Kentucky transmission revenues and T.A. revenues to its PJM OATT net costs. Total Kentucky transmission related revenues in excess of PJM OATT net costs will constitute an over recovery. PJM OATT net cost in excess of the total Kentucky transmission related revenues will constitute an under recovery.

Q. **HOW WILL PJM OATT NET COST OVER/UNDER RECOVERIES BE CALCULATED ONCE THIS IS IMPLEMENTED?**

A. On a monthly basis, the Kentucky jurisdictional revenues collected under the T.A. plus the base transmission revenues will be compared to the total of Kentucky jurisdictional PJM OATT net costs incurred for that period. The difference between these revenues and the PJM OATT net costs would be deferred as either a net regulatory liability (over recovery) or a net regulatory asset (under recovery) for future refund or recovery through the Balancing Adjustment Factor of the T.A.

Q. **WILL KPCo'S ACTUAL OVER/UNDER RECOVERY OF PJM OATT NET COSTS BE DEFERRED UNTIL CREDITED TO / RECOVERED FROM CUSTOMERS, RESPECTIVELY?**

A. Yes. KPCo plans to record deferrals of its actual over/under recovered PJM OATT net costs based on the types of costs identified in this application until over-collections are credited or under collections are recovered from customers in a future period.

Q. **WHAT IS THE BASIS IN ACCOUNTING PRINCIPLES GENERALLY ACCEPTED IN THE UNITED STATES OF AMERICA (GAAP) FOR KPCo DEFERRING PJM OATT NET COSTS IN EXCESS OF TOTAL KENTUCKY TRANSMISSION RELATED REVENUES AS A REGULATORY ASSET?**

A. Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) 980-340-25-1, formerly Paragraph 9 of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, as adopted by the FERC in its Order 390 and used in the FERC USofA, states the following: "An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: a.) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes. b.) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs." FASB ASC 980 defines "capitalize" as cost that would be recorded as an asset and this resulting asset is commonly known as a deferred cost or a regulatory asset. The term "probable" is defined as a future event that is likely to occur but is not certain consistent with its use in FASB ASC 450, formerly SFAS No. 5, *Accounting for Contingencies*.

Q. **WHAT IS NEEDED TO ESTABLISH PROBABILITY OF RECOVERY?**

A. The final order in this proceeding should clearly provide for the future recovery of PJM OATT net costs in excess of applicable Kentucky transmission related revenues in the next proceeding.

Q. **HOW WILL THE TWO CRITERIA OF FASB ASC 980 BE MET TO ENABLE KPCo TO CAPITALIZE OR DEFER UNDER-RECOVERED PJM OATT NET COSTS AS A REGULATORY ASSET?**

A. If an Order from the Commission approves the recovery of under-recovered PJM OATT net costs, then the two criteria of FASB ASC 980 for capitalizing or deferring net under-recovered PJM OATT net costs as a regulatory asset will be met.

Q. DOES THE DEFERRAL ACCOUNTING TREATMENT YOU PROPOSE FOR RECORDING A REGULATORY LIABILITY IN THE INSTANCE WHERE KPCo HAS AN OVER RECOVERY OF PJM OATT NET COSTS COMPLY WITH GAAP?

A. Yes. FASB ASC 980-405 defines accounting for instances when a regulator imposes a liability on a cost based regulated enterprise. One of the instances in which a liability can be imposed on a regulated enterprise occurs when a regulator provides current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred, future rates will be reduced. If the regulator requires that any over-collection of such recoverable costs be returned to ratepayers, any over-recovery shall be recognized as a regulatory liability, or if a net cumulative under recovery exists in the form of a regulatory asset, a subsequent over recovery would be accounted for as a reduction in such net cumulative under recovery regulatory asset until the regulatory asset is eliminated.

Q. IN ADDITION TO THE REQUIREMENTS OF FASB ASC 980, ARE THERE UNDERLYING REASONS THAT SUPPORT KPCo PRACTICING

OVER/UNDER RECOVERY DEFERRAL ACCOUNTING FOR ITS ACTUAL PJM OATT NET COSTS?

A. Yes. The proper matching of costs with their recovery in revenues in the same accounting period necessitates that KPCo's actual unrecovered PJM OATT net costs be deferred since they will be recovered in a future period. Failure to practice deferral accounting for unrecovered actual PJM OATT net costs recoverable through the T.A. would understate KPCo's earnings in the periods prior to their recovery and overstate earnings in the periods in which they are recovered through the T.A.

Q. WHAT ACCOUNTING WOULD KPCo EMPLOY TO RECORD THE PJM OATT NET COST OVER- OR UNDER -RECOVERIES?

A. Kentucky jurisdictional transmission revenues (T.A. plus the base transmission revenues) would be recorded in the appropriate FERC revenue Accounts 440 through 446. These revenues would be compared to total PJM OATT net costs.

If, within a given month, these revenues are greater than the PJM OATT net costs, KPCo will record the over recovery as a decrease (charge) to Account 456.1, Revenues from Transmission of Electricity and an increase (credit) to Account 254, Other Regulatory Liabilities, if the cumulative balance is an over recovery. If the cumulative balance is an under recovery, the charge will be to Account 566, Miscellaneous Transmission Expense and Account 182.3, Other Regulatory Assets, will be credited until the under recovery balance is eliminated.

If these monthly revenues are less than the monthly PJM OATT net costs, KPCo will record the under recovery as a decrease (credit) to Account 566, Miscellaneous Transmission Expense, with a corresponding debit recorded to Account 182.3, Other Regulatory Assets, if the cumulative balance is an under recovery. If the cumulative balance is an over recovery, the credit will be to Account 456.1, Revenues from Transmission of Electricity, and Account 254, Other Regulatory Liabilities, will be debited until the over recovery balance is eliminated. On an annual basis any over or under recovered balance will be included as a reconciliation item to either reduce an over recovery or increase an under recovery amount to be collected in the next period.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes it does.

AFFIDAVIT

Diana L. Gregory, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to her at a hearing before the Public Service Commission of Kentucky, she would give the answers recorded following each of said questions and that said answers are true.

Diana L. Gregory

Diana L. Gregory

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Diana L. Gregory this 17th day of December 2009.

Robin S. Smith

Notary Public

My Commission Expires November 2, 2013

NOTARIAL SEAL STATE OF OHIO

ROBIN S. SMITH
NOTARY PUBLIC
IN AND FOR THE STATE OF OHIO
MY COMMISSION EXPIRES
NOVEMBER 2, 2013

KENTUCKY POWER COMPANY
TRANSMISSION ADJUSTMENT TARIFF
CHARGES AND CREDITS

Line No.	Line Item	FERC Account	Current AEP Sub-Account
1	Network Integration Transmission Service (NITS) Charges	456.1	4561035
2	Firm and Non-Firm Point to Point (PTP) Transmission Revenues	456.1	4561005
3	Ancillary Service Schedule 1A Charges (Transmission Owner Scheduling, System Control and Load Dispatching)	456.1	4561036
4	PJM Transmission Enhancement Charges		
5	Major Projects	565.0	5650012
6	Other Projects	565.0	5650012
7	PJM Administrative Charges *	561.4	5614001
		561.4	5614007
		561.8	5618001
		575.7	5757001
8	RTO Formation Cost Recovery Charges	456.1	4561002
9	PJM Expansion Cost Recovery Charges	456.1	4561003

* Allocation to accounts is in accordance with FERC Order 668 and instruction from PJM.

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY
OF
DANIEL E. HIGH

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
DANIEL E. HIGH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

DIRECT TESTIMONY OF
DANIEL E. HIGH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Introduction

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

A. My name is Daniel High. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I currently hold the position of Regulatory Consultant I in the Regulated Pricing and Analysis department for the American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), the parent company of Kentucky Power Company (KPCo or the Company).

Background

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

A. In December 1989, I received a Bachelors of Science Degree in Energy Management from West Liberty University. In May 1997, I received a Masters of Business Administration degree from Ashland University.

In February 1990, I joined Columbus Southern Power Company as a Marketing and Customer Services Representative in the Marketing and Customer Services Department of the Columbus Region. In August 1998, I joined the Regulated Pricing & Analysis Department as a Regulatory Consultant. From 2006 through 2008, I performed duties as a Regulatory Consultant in Transmission & Interconnection Services under the Regulatory Services Department, where I was responsible for rate design and maintaining wholesale contracts. In January 2009, I returned to Regulated Pricing & Analysis under the Regulatory Services Department as a Regulatory Consultant. My responsibilities include preparation of cost-of-service studies, rate design and tariff provisions for the AEP operating companies, and special contracts and pricing for retail and wholesale customers.

Q. HAVE YOU TAKEN ANY COURSES IN COST ALLOCATION AND RATE DESIGN?

A. Yes. In 1999, I attended the Edison Electric Institute's (EEI) school on cost allocation and rate design. In 2003, I also attended EEI's advanced cost allocation and rate design school.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Kentucky Power Company, which I will refer to throughout my testimony either as KPCo, or as "the Company".

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support and describe the development of the Company's class cost of service study. The Company's class cost of service study is attached as Exhibit DEH-1.

Q. PLEASE DESCRIBE THIS EXHIBIT.

A. Exhibit DEH-1 is the class cost of service study for the Company for test year ended September 30, 2009.

Class Cost of Service Study

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. Cost studies are 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 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 DATA SOURCE IS USED IN THE DEVELOPMENT OF A COST OF SERVICE STUDY?

A. The historic accounting records of KPCo 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 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.

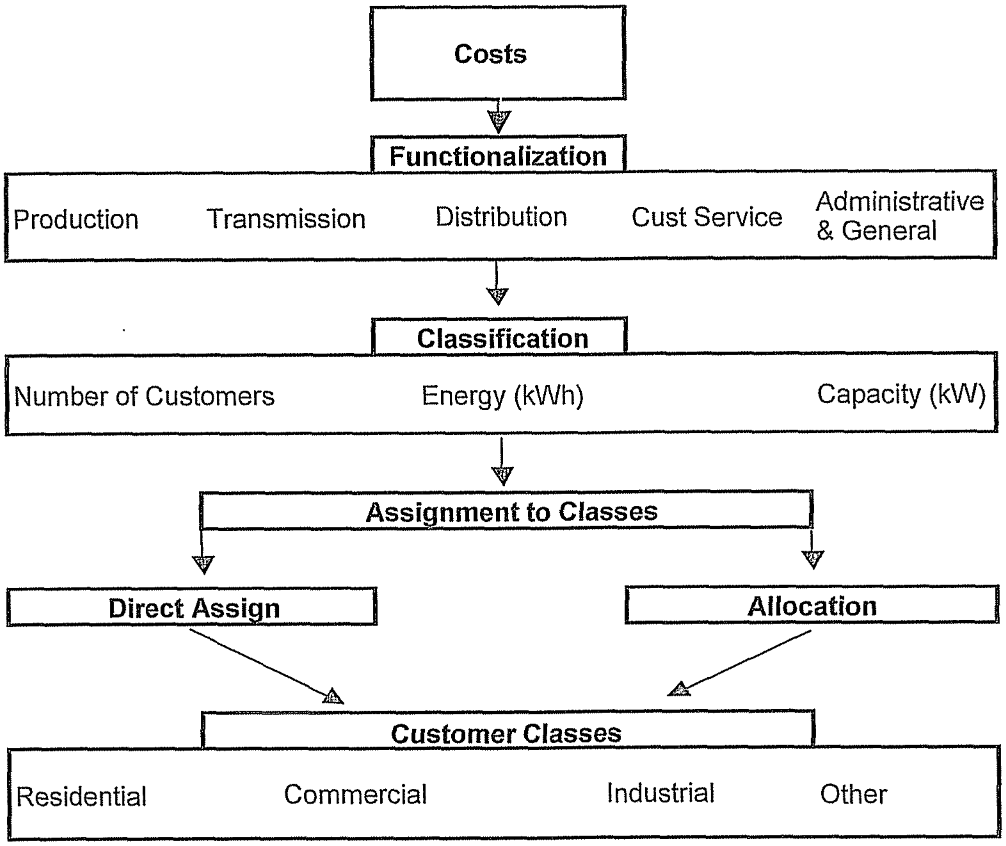
A. The third and final step is to allocate the functional and classified costs among the classes of customers based on how the costs are incurred for each class. Allocation factors are used to assign these costs to the various customer classes. Customer classes are determined and grouped according to 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. A weighted number of customers allocation factor 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 either 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 KPCo customer classes.

Allocation Basis

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 KPCo's 12 monthly peaks on the production facilities for the test period ended September 30, 2009.

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 KPCo'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 DEH-1, 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 KPCo's 12 monthly peak demands on the primary distribution system.

Accounts 364 through 367 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 367 were allocated using the average of 12 monthly peak demands on the distribution system. The secondary component of accounts 364 through 367 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.

Account 368 was allocated to the customer classes served from those facilities using the appropriate secondary voltage demand allocation factors described above.

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. Classification of distribution plant into demand and customer components was accomplished through a study of the components of distribution plant.

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.

Q. PLEASE DESCRIBE THE ALLOCATION OF OTHER RATE BASE COMPONENTS.

A. Working Capital was divided into cash, material and supplies and prepayments. Cash working capital is made up of two components. The first component is related to system sales and is split between demand and energy. The second component is related to O&M expense net of system sales. The component related to system sales demand was allocated based upon the production demand allocation factor. System sales energy was allocated based upon the energy allocation factor. The O&M expense net of system sales was allocated based upon the allocation of total O&M expense. The energy allocation factor allocates costs based on the class energy used during the period compared to the total energy used by all classes. Materials and supplies were split between fuel stock, production and transmission and distribution. Fuel stock was 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. Plant Held for Future Use is transmission-related and allocated using transmission electric plant in service. Construction Work in Progress was functionalized and allocated using appropriate related factors. Customer Deposits were assigned based on an analysis of accounting records. Accumulated Deferred Federal Income Tax Credits were allocated on electric plant in service and customer advances were allocated based on the number of customers.

Q. HOW WERE REVENUES DEVELOPED FOR EACH CLASS?

A. Sales revenue was directly assigned to each class.

Forfeited discounts were directly assigned based on an analysis of accounting records. Miscellaneous service revenue was allocated on distribution electric 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 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 classified as demand-related and allocated using the transmission 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 demand- and customer-related and allocated using the allocated subtotal of accounts 581 through 589.

Account 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. All customer accounting expenses were classified as customer-related.

Accounts 907 through 916 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 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. HOW WERE TAXES ASSIGNED TO THE CUSTOMER CLASSES?

A. Individual other tax items were allocated and classified using the appropriate demand 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 functionalized components of the AFUDC offset were allocated using the corresponding plant allocator.

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	-2.88 %

Small General Service	6.37 %
Medium General Service	5.64 %
Large General Service	4.05 %
Quantity Power	5.23 %
Commercial and Industrial Power - Time of Day	6.37 %
Municipal Waterworks	6.55 %
Outdoor Lighting	6.86 %
Street Lighting	14.45 %
Total KPCo Jurisdiction	1.11 %

Q. HOW ARE THESE RATES OF RETURN USED IN THIS PROCEEDING?

A. Witness Roush uses the earned rates of return for each class as a basis for the allocation of the revenue increase required for each class.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT

Daniel E. High, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Daniel E. High

Daniel E. High

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Daniel E. High this 16th day of December 2009.

Ellen Q. McQuinch

Notary Public

My Commission Expires May 11th, 2011

KENTUCKY POWER COMPANY
12 CP CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009
Summary

	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
RATE BASE										
GROSS UTILITY PLANT	1,582,377,482	852,202,887	44,656,618	148,959,296	165,115,742	122,186,146	215,242,975	1,397,189	29,225,294	3,391,335
TOTAL DEPRECIATION RESERVE	524,029,696	273,783,188	13,666,004	48,536,103	54,211,943	43,787,210	81,443,144	456,676	7,292,145	853,284
ACCUMULATED DEPRECIATION - ADJUSTMENT	12,484,677	6,579,905	328,029	1,162,181	1,297,426	1,030,852	1,890,653	10,936	164,963	19,733
NET UTILITY PLANT	1,045,863,109	571,839,795	30,662,585	99,261,012	109,606,373	77,368,084	131,909,178	929,577	21,768,186	2,518,318
PLANT HELD FOR FUTURE USE TRANS	30,164	14,071	579	2,660	3,051	3,177	6,601	25	0	0
TOTAL WORKING CAPITAL	132,950,742	57,602,043	3,031,077	11,517,703	13,954,556	13,823,850	31,714,063	134,567	1,013,652	159,231
TOTAL CWIP	26,685,580	13,721,119	673,508	2,457,846	2,754,364	2,312,148	4,372,054	23,086	332,869	38,585
TOTAL RATE BASE OFFSETS	(192,840,492)	(108,043,740)	(5,672,163)	(18,152,530)	(19,004,068)	(14,029,779)	(24,101,821)	(154,724)	(3,306,220)	(375,448)
TOTAL RATE BASE	1,012,689,103	535,133,289	28,695,586	95,086,690	107,314,277	79,477,481	143,900,076	932,532	19,808,487	2,340,686
OPERATING REVENUES										
SALES OF ELECTRICITY	509,765,263	196,964,517	14,551,918	51,640,578	58,995,442	54,976,107	124,336,206	582,698	6,588,349	1,129,448
OTHER OPERATING REVENUE	12,032,042	7,674,214	506,989	1,392,877	1,340,986	445,474	357,138	10,644	272,727	30,993
TOTAL OPERATING REVENUE	521,797,305	204,638,731	15,058,907	53,033,455	60,336,428	55,421,581	124,693,344	593,342	6,861,076	1,160,441
OPERATING EXPENSES										
ADJUSTED OPERATING AND MAINTENANCE EXP	455,994,177	204,101,152	10,713,027	39,745,818	48,265,505	45,001,485	103,383,284	451,225	3,831,447	501,234
ADJUSTED DEPRECIATION EXPENSE	63,543,436	34,488,088	1,816,626	5,985,259	6,625,108	4,826,017	8,427,327	56,211	1,179,582	139,220
ADJUSTED TAXES OTHER THAN INCOME TAX	11,473,932	6,066,933	323,585	1,080,102	1,197,680	917,500	1,671,298	10,357	183,212	23,265
TOTAL STATE INCOME TAXES	(2,993,754)	(4,011,177)	37,203	160,603	35,936	178,831	596,566	2,949	(19,266)	24,600
FEDERAL INCOME TAXES	(15,209,414)	(19,484,293)	392,545	900,607	96,928	545,142	1,844,303	13,460	345,737	136,158
TOTAL EXPENSES	512,808,377	221,160,702	13,282,987	47,872,389	56,221,157	51,468,974	115,922,777	534,201	5,520,712	824,477
NET OPERATING INCOME	8,988,928	(16,521,971)	1,775,920	5,161,066	4,115,271	3,952,607	8,770,567	59,141	1,340,364	335,964
AFUDC OFFSET	2,215,125	1,112,601	51,811	201,531	227,328	202,427	396,498	1,903	18,826	2,199
ADJUSTED NET OPERATING INCOME	11,204,053	(15,409,370)	1,827,731	5,362,597	4,342,599	4,155,034	9,167,065	61,044	1,359,190	338,163
RATE OF RETURN %	1.11%	-2.88%	6.37%	5.64%	4.05%	5.23%	6.37%	6.55%	6.86%	14.45%
RATE OF RETURN INDEX	100	(260)	576	510	366	473	576	592	620	1,306

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
ELECTRIC PLANT IN SERVICE											
PRODUCTION PLANT DEMAND	PROD_DEMAND	531,432,767	251,234,666	10,210,525	47,025,005	53,875,916	54,665,604	113,973,492	447,560	0	0
TRANSMISSION PLANT OTHER DEMAND TOTAL	TRANS_TOTAL	428,413,799	199,840,965	8,217,286	37,785,042	43,339,280	45,120,009	93,754,865	356,353	0	0
TRANSMISSION PLANT GSU TOTAL	PROD_DEMAND	1,582,896	748,314	30,412	140,066	160,472	162,824	339,475	1,333	0	0
TRANSMISSION PLANT		429,996,695	200,589,279	8,247,698	37,925,108	43,499,752	45,282,833	94,094,340	357,686	0	0
DISTRIBUTION PLANT											
360 LAND AND LAND RIGHTS	DIST_CPD	6,506,018	4,291,532	177,560	798,666	837,646	393,084	0	7,530	0	0
361 STRUCTURES AND IMPROVEMENTS	DIST_CPD	4,229,545	2,789,914	115,431	519,210	544,551	255,543	0	4,895	0	0
362 STATION EQUIPMENT	DIST_CPD	56,358,693	37,175,602	1,538,125	6,918,479	7,256,146	3,405,111	0	65,231	0	0
364 POLES	DIST_POLES	154,130,634	106,354,818	4,889,711	17,449,186	19,312,426	5,269,543	0	170,858	576,831	107,261
365 OVERHEAD LINES	DIST_OHLINES	138,152,587	94,380,033	4,244,398	15,938,442	17,418,131	5,542,329	0	154,673	400,170	74,411
366 UNDERGROUND CONDUIT	DIST_UGLINES	4,921,900	3,374,735	153,006	563,969	619,152	186,843	0	5,491	15,771	2,933
367 UNDERGROUND LINES	DIST_UGLINES	7,962,163	5,459,313	247,519	912,334	1,001,603	302,256	0	8,882	25,512	4,744
368 TRANSFORMERS	DIST_TRANSF	101,021,740	71,790,869	3,508,509	10,782,689	12,421,582	1,657,048	0	108,636	634,436	117,973
369 SERVICES	DIST_SERV	40,657,586	26,148,943	4,103,399	1,389,984	132,379	182	0	3,637	8,868,878	10,183
370 METERS	DIST_METERS	23,285,957	11,627,349	5,340,111	2,802,165	1,667,845	1,135,701	707,920	4,866	0	0
371 INSTALLATIONS ON CUST PREMISES	DIST_OL	18,199,577	0	0	0	0	0	0	0	18,199,577	0
372 LEASED PROP ON CUST PREMISES	DIST_OL	0	0	0	0	0	0	0	0	0	0
373 STREET LIGHTING	DIST_SL	2,974,559	0	0	0	0	0	0	0	0	2,974,559
DISTRIBUTION PLANT TOTAL		558,400,959	363,393,107	24,317,770	58,075,123	61,211,461	18,147,640	707,920	534,700	28,721,174	3,292,064
PTD PLANT	FORMULA	1,519,830,421	815,217,051	42,775,993	143,025,236	158,587,129	118,096,077	208,775,753	1,339,945	28,721,174	3,292,064
GENERAL PLANT TOTAL	LABOR_M	54,714,617	31,266,271	1,616,710	4,998,416	5,505,700	3,905,099	6,808,294	48,089	472,624	93,415
HR-J 765 LINE - AFUDC	BULK_TRANS	1,700,358	803,844	32,669	150,460	172,380	174,907	364,667	1,432	0	0
ASSET RETIREMENT OBLIGATION (ARO)	PROD_DEMAND	-3,290,698	-1,555,676	-63,225	-291,185	-333,606	-338,496	-705,738	-2,771	0	0
ELECTRIC PLANT IN SERVICE		1,572,954,698	845,731,489	44,362,148	147,882,927	163,931,602	121,837,587	215,242,975	1,386,695	29,193,797	3,385,478
ELECTRIC PLANT IN SERVICE - ADJUSTMENT		9,422,784	6,471,398	294,470	1,076,368	1,184,139	348,559	0	10,495	31,497	5,857
GROSS UTILITY PLANT	FORMULA	1,582,377,482	852,202,887	44,656,618	148,959,296	165,115,742	122,186,146	215,242,975	1,397,189	29,225,294	3,391,335
DEPRECIATION RESERVE											
PRODUCTION	RB_GUP_EPIS_P	223,176,661	105,506,693	4,287,938	19,748,281	22,625,340	22,956,972	47,863,484	187,954	0	0
TRANSMISSION	RB_GUP_EPIS_T	138,142,478	64,442,123	2,649,689	12,183,974	13,974,906	14,547,746	30,229,128	114,912	0	0
DISTRIBUTION	RB_GUP_EPIS_D	137,689,440	89,604,777	5,996,229	14,320,053	15,093,405	4,474,810	174,558	131,845	7,082,012	811,751
GENERAL	RB_GUP_EPIS_G	24,326,628	13,901,275	718,805	2,222,342	2,447,885	1,736,243	3,027,031	21,381	210,133	41,533
HR-J POST IN-SERVICE	BULK_TRANS	694,489	328,319	13,343	61,453	70,406	71,436	148,943	585	0	0
TOTAL DEPRECIATION RESERVE		524,029,696	273,783,188	13,666,004	48,536,103	54,211,943	43,767,210	81,443,144	456,676	7,292,145	853,284
ACCUMULATED DEPRECIATION - ADJUSTMENT	FORMULA	12,484,677	6,579,905	328,029	1,162,181	1,297,426	1,030,852	1,890,653	10,936	164,963	19,733
NET UTILITY PLANT	FORMULA	1,045,863,109	571,839,795	30,662,585	99,261,012	109,606,373	77,366,084	131,909,178	929,577	21,768,186	2,518,318

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
PLANT HELD FOR FUTURE USE TRANS	RB_GUP_EPIS_T	30,164	14,071	579	2,660	3,051	3,177	6,601	25	0	0
WORKING CAPITAL											
WORKING CAPITAL CASH											
WORKING CAPITAL CASH EXCL SYS SALES	EXP_OM	48,802,040	21,351,135	1,099,600	4,262,889	5,097,072	5,108,535	11,445,008	49,211	330,559	58,032
SYSTEM SALES ADD BACK DEMAND	PROD_DEMAND	1,088,084	514,391	20,906	96,282	110,308	111,925	233,355	916	0	0
SYSTEM SALES ADD BACK ENERGY	PROD_ENERGY	17,940,858	6,339,452	353,874	1,494,850	1,900,546	2,225,660	5,471,924	20,162	112,393	21,995
TOTAL WORKING CAPITAL CASH		67,830,982	28,204,978	1,474,379	5,854,020	7,107,927	7,446,120	17,150,288	70,290	442,952	80,027
WORKING CAPITAL CASH - ADJUSTMENT		8,197,233	4,161,510	239,529	705,339	936,116	516,651	1,477,902	7,192	148,372	4,622
WORKING CAPITAL MATERIALS & SUPPLIES											
FUEL	PROD_ENERGY	42,771,452	15,113,412	843,645	3,563,760	4,530,949	5,306,029	13,045,204	48,067	267,947	52,438
PRODUCTION	PROD_DEMAND	7,560,912	3,574,419	145,269	669,044	766,515	777,750	1,621,548	6,368	0	0
EMISSIONS	PROD_ENERGY	8,159,539	2,883,196	160,943	679,861	864,372	1,012,235	2,488,642	9,170	51,117	10,004
TRANSMISSION AND DISTRIBUTION	TDPLANT	2,302,422	1,313,381	75,805	223,593	243,901	147,911	221,306	2,079	66,790	7,656
TOTAL MATERIALS & SUPPLIES		60,794,325	22,884,408	1,225,662	5,136,259	6,405,737	7,243,925	17,376,700	65,683	385,854	70,097
WORKING CAPITAL MATERIALS & SUPPLIES - ADJUSTMENT		(21,230,418)	(7,501,828)	(418,759)	(1,768,940)	(2,249,022)	(2,633,748)	(6,475,233)	(23,859)	(133,001)	(26,028)
WORKING CAPITAL PREPAYMENTS	RB_GUP_EPIS	1,968,585	1,058,450	55,520	185,079	205,164	152,482	269,381	1,735	36,537	4,237
WORKING CAPITAL PREPAYMENTS - ADJUSTMENT		15,390,035	8,794,524	454,746	1,405,946	1,548,634	1,098,420	1,915,025	13,526	132,939	26,275
TOTAL WORKING CAPITAL	FORMULA	132,950,742	57,602,043	3,031,077	11,517,703	13,954,556	13,823,850	31,714,063	134,567	1,013,652	159,231
CONSTRUCTION WORK IN PROGRESS											
PRODUCTION	RB_GUP_EPIS_P	5,665,163	2,678,204	108,846	501,294	574,326	582,745	1,214,977	4,771	0	0
TRANSMISSION	RB_GUP_EPIS_T	14,048,792	6,553,625	269,468	1,239,084	1,421,218	1,479,474	3,074,237	11,686	0	0
DISTRIBUTION	RB_GUP_EPIS_D	6,370,789	4,145,947	277,441	662,578	698,361	207,046	8,077	6,100	327,679	37,559
GENERAL	RB_GUP_EPIS_G	600,836	343,343	17,754	54,889	60,460	42,883	74,764	528	5,190	1,026
TOTAL CWIP		26,685,580	13,721,119	673,508	2,457,846	2,754,364	2,312,148	4,372,054	23,086	332,869	38,585
RATE BASE OFFSETS											
ACCUMULATED DEFERRED FIT	RB_GUP	(170,075,156)	(91,444,410)	(4,796,641)	(15,989,788)	(17,725,045)	(13,173,645)	(23,273,069)	(149,936)	(3,156,569)	(366,054)
CUSTOMER ADVANCES	TDPLANT	(59,442)	(33,908)	(1,957)	(5,773)	(6,297)	(3,819)	(5,713)	(54)	(1,724)	(198)
CUSTOMER DEPOSITS	CUST_DEP	(17,319,382)	(13,487,338)	(714,404)	(1,664,889)	(730,704)	(467,868)	(152,780)	0	(101,398)	0
RATE BASE OFFSETS - ADJUSTMENT	LABOR_M	(5,386,512)	(3,078,083)	(159,161)	(492,081)	(542,022)	(384,447)	(670,259)	(4,734)	(46,529)	(9,196)
TOTAL RATE BASE OFFSETS		(192,840,492)	(108,043,740)	(5,672,163)	(18,152,530)	(19,004,068)	(14,029,779)	(24,101,821)	(154,724)	(3,306,220)	(375,448)
TOTAL RATE BASE	FORMULA	1,012,689,103	535,133,289	28,695,586	95,086,690	107,314,277	79,477,481	143,900,076	932,532	19,808,487	2,340,686

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
OPERATING REVENUES											
TOTAL REVENUE	REVSALES	507,240,229	197,715,587	14,507,207	51,889,457	57,778,205	55,902,899	121,184,366	582,698	6,546,076	1,133,734
TOTAL REVENUE YEAR END CUSTOMERS	REVYEC	2,525,034	(751,070)	44,711	(248,879)	1,217,237	(926,792)	3,151,840	0	42,273	(4,286)
SALES OF ELECTRICITY		509,765,263	196,964,517	14,551,918	51,640,578	58,995,442	54,976,107	124,336,206	582,698	6,588,349	1,129,448
OTHER OPERATING REVENUES											
FORFEITED DISCOUNTS	FORT	1,809,068	1,103,155	140,519	304,613	149,217	21,134	73,152	0	17,278	0
MISCELLANEOUS SERVICE REVENUE	RB_GUP_EPIS_D	395,706	257,515	17,233	41,154	43,377	12,860	502	379	20,353	2,333
RENT FROM ELECTRIC PROP POLES	DIST_POLES	4,776,990	3,296,268	151,547	540,805	598,552	163,320	0	5,295	17,878	3,324
RENT FROM ELECTRIC PROP OTHER DIST	RB_GUP_EPIS_D	330,170	214,866	14,379	34,339	36,193	10,730	419	316	16,982	1,947
OTHER ELECTRIC REVENUE DIST	RB_GUP_EPIS_D	3,006,371	1,956,470	130,924	312,670	329,556	97,705	3,811	2,879	154,632	17,724
OTHER ELECTRIC REVENUE WHEELING	TRANS_TOTAL	69,928	32,619	1,341	6,167	7,074	7,365	15,303	58	0	0
OTHER ELECTRIC REVENUE PRODUCTION	PROD_ENERGY	862,171	304,651	17,006	71,837	91,333	106,957	262,960	969	5,401	1,057
TOTAL OTHER OPERATING REVENUES		11,250,404	7,165,544	472,949	1,311,585	1,255,303	420,071	356,147	9,896	232,524	26,385
OTHER OPERATING REVENUE - ADJUSTMENT		781,638	508,670	34,040	81,292	85,683	25,403	991	748	40,203	4,608
TOTAL OPERATING REVENUE		521,797,305	204,638,731	15,058,906	53,033,456	60,336,427	55,421,580	124,693,344	593,343	6,861,076	1,160,441

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
OPERATION AND MAINTENANCE EXPENSE											
O&M EXPENSE PRODUCTION											
GENERATION EXPENSE DEMAND	PROD_DEMAND	20,811,678	9,838,714	399,859	1,841,567	2,109,859	2,140,784	4,463,367	17,527	0	0
GENERATION EXPENSE ENERGY	PROD_ENERGY	9,981,548	3,527,008	196,881	831,673	1,057,385	1,238,265	3,044,351	11,217	62,531	12,237
GENERATION EXPENSE FUEL	PROD_ENERGY	191,973,390	67,834,335	3,786,577	15,995,415	20,336,500	23,815,334	58,551,486	215,742	1,202,643	235,359
SYSTEM SALES	PROD_DEMAND	(8,704,672)	(4,115,131)	(167,245)	(770,252)	(882,468)	(895,402)	(1,866,844)	(7,331)	0	0
SYSTEM SALES	PROD_ENERGY	(143,526,865)	(50,715,620)	(2,830,994)	(11,958,802)	(15,204,368)	(17,805,281)	(43,775,396)	(161,297)	(899,143)	(175,963)
PURCHASED POWER DEMAND	PROD_DEMAND	98,530,187	46,580,113	1,893,080	8,718,662	9,988,854	10,135,266	21,131,233	82,980	0	0
PURCHASED POWER ENERGY	PROD_ENERGY	152,824,335	54,000,907	3,014,382	12,733,477	16,189,286	18,958,682	46,611,105	171,746	957,388	187,362
SYSTEM CONTROL	PROD_DEMAND	394,700	186,594	7,583	34,926	40,014	40,601	84,649	332	0	0
TOTAL PRODUCTION EXPENSES		474,515,838	181,967,672	9,298,363	40,155,720	49,721,897	56,328,931	133,886,192	499,544	2,222,562	434,958
O&M EXPENSE TOTAL TRANSMISSION	RB_GUP_EPIS_T	309,714	144,479	5,941	27,316	31,332	32,616	67,773	258	0	0
O&M EXPENSE REGIONAL MARKET	TRANS_TOTAL	1,174,225	547,737	22,522	103,564	118,787	123,668	256,970	977	0	0
DISTRIBUTION OPERATION EXPENSE											
580 SUPERVISION & ENGINEERING	TOTOXEXP	913,465	578,576	58,322	97,229	96,536	32,760	4,081	803	34,418	10,740
581 LOAD DISPATCHING	DIST_CPD	2,432	1,604	66	299	313	147	0	3	0	0
582 STATION EXPENSES	DIST_CPD	233,407	153,961	6,370	28,653	30,051	14,102	0	270	0	0
583 OVERHEAD LINES	DIST_OHLINES	1,137,658	777,200	34,952	131,250	143,435	45,640	0	1,274	3,295	613
584 UNDERGROUND LINES	DIST_UGLINES	83,980	57,581	2,611	9,623	10,564	3,188	0	94	269	50
585 STREET LIGHTING	DIST_SL	53,816	0	0	0	0	0	0	0	0	53,816
586 METERS	DIST_METERS	820,535	409,717	188,171	98,741	58,770	40,019	24,945	171	0	0
587 CUSTOMER INSTALLS	DIST_PCUST	135,655	87,162	13,678	4,680	498	28	0	12	29,562	34
588 MISCELLANEOUS DISTRIBUTION	RB_GUP_EPIS_D	2,775,090	1,805,958	120,852	288,616	304,203	90,188	3,518	2,657	142,736	16,361
589 RENTS	RB_GUP_EPIS_D	1,575,316	1,025,175	68,603	163,837	172,685	51,197	1,997	1,508	81,026	9,287
TOTAL DISTRIBUTION OPER EXP	FORMULA	7,731,354	4,896,935	493,626	822,928	817,055	277,269	34,542	6,792	291,307	90,901
DISTRIBUTION MAINTENANCE EXPENSE											
590 SUPERVISION & ENGINEERING	TOTMXEXP	8,891	5,985	275	997	1,096	325	0	10	181	21
591 STRUCTURES	DIST_CPD	5,205	3,433	142	639	670	314	0	6	0	0
592 STATION EQUIPMENT	DIST_CPD	512,025	337,744	13,974	62,855	65,923	30,936	0	593	0	0
593 OVERHEAD LINES	TOTOHLINES	29,521,237	20,274,654	922,565	3,372,223	3,709,866	1,092,022	0	32,879	98,679	18,349
594 UNDERGROUND LINES	TOTUGLINES	186,163	127,644	5,787	21,331	23,418	7,067	0	208	596	111
595 LINE TRANSFORMER	DIST_TRANSF	175,156	124,474	6,083	18,696	21,537	2,873	0	188	1,100	205
596 STREET LIGHTING	DIST_SL	54,605	0	0	0	0	0	0	0	0	54,605
597 METERS	DIST_METERS	53,708	26,818	12,317	6,463	3,847	2,619	1,633	11	0	0
598 MISC DISTRIBUTION PLANT	DIST_OL	532,162	0	0	0	0	0	0	0	532,162	0
TOTAL DISTRIBUTION MAINT EXP	FORMULA	31,049,152	20,900,753	961,143	3,483,204	3,826,357	1,136,158	1,633	33,895	632,719	73,291
DISTRIBUTION EXPENSES		38,780,506	25,797,688	1,454,769	4,306,132	4,643,412	1,413,427	36,175	40,687	924,025	164,191
CUSTOMER ACCOUNTS											
901 SUPERVISION	TOTOX234	413,373	409,076	20,793	9,792	1,550	199	41	18	(28,111)	13
902 METER READ	CUST_902	754,340	601,634	94,411	48,659	8,234	1,092	226	84	0	0
903 CUSTOMER RECORDS	CUST_903	6,009,640	4,620,683	459,606	157,602	17,517	1,771	366	407	750,547	1,141
904 UNCOLLECTIBLES	CUST_TOTAL	(4,235,288)	(2,719,913)	(426,820)	(146,359)	(16,266)	(1,646)	(340)	(378)	(922,507)	(1,059)
905 MISCELLANEOUS	TOTOX234	7,516	7,438	378	178	28	4	1	0	(511)	0
TOTAL CUSTOMER ACCOUNTS		2,949,581	2,918,918	148,368	69,873	11,063	1,420	293	131	(200,581)	95
TOTAL CUSTOMER SERVICES	CUST_TOTAL	1,802,110	1,157,320	181,611	62,275	6,921	700	145	161	392,526	451

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	RETAIL	TOTAL RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
ADMINISTRATIVE & GENERAL EXPENSE											
A&G PRODUCTION DEMAND	PROD_DEMAND	8,343,100	3,944,198	160,298	738,258	845,812	858,209	1,789,299	7,026	0	0
A&G PRODUCTION ENERGY	PROD_ENERGY	2,865,019	1,012,362	56,511	238,716	303,503	355,421	873,825	3,220	17,948	3,513
A&G TRANSMISSION	EXP_OM_TRAN	1,293,502	603,382	24,810	114,084	130,854	136,228	283,068	1,076	0	0
A&G DISTRIBUTION	EXP_OM_DIST	8,706,885	5,792,021	326,620	966,800	1,042,525	317,338	8,122	9,135	207,459	36,864
A&G CUSTOMER ACCOUNTS	EXP_OM_CUSTACCT	1,523,898	1,508,056	76,654	36,100	5,716	734	152	68	-103,630	49
A&G CUSTOMER SERVICE	EXP_OM_CUSTSERV	382,387	245,570	38,536	13,214	1,469	149	31	34	83,289	96
TOTAL A&G EXPENSE EXCLUDING REGULATORY		23,114,791	13,105,590	683,430	2,107,172	2,329,878	1,668,079	2,954,496	20,559	205,067	40,521
A&G REGULATORY RECLASSIFIED	FORMULA	1,088	424	31	111	124	120	260	1	14	2
TOTAL A & G EXPENSES		23,115,879	13,106,014	683,461	2,107,283	2,330,002	1,668,199	2,954,756	20,560	205,081	40,524
TOTAL O&M EXPENSES		390,416,316	170,809,076	8,796,796	34,103,109	40,776,578	40,868,277	91,560,064	393,690	2,644,470	464,256
OPERATION & MAINTENANCE EXPENSE - ADJUSTMENT	FORMULA	65,577,861	33,292,076	1,916,231	5,642,709	7,488,927	4,133,207	11,823,219	57,535	1,186,977	36,979
ADJUSTED OPERATING AND MAINTENANCE EXP		455,994,177	204,101,152	10,713,027	39,745,818	48,265,505	45,001,485	103,383,284	451,225	3,831,447	501,234
DEPRECIATION EXPENSE											
PRODUCTION	RB_GUP_EPIS_P	19,561,410	9,247,650	375,837	1,730,935	1,983,109	2,012,176	4,195,229	16,474	0	0
TRANSMISSION	RB_GUP_EPIS_T	7,597,948	3,544,369	145,735	670,128	768,631	800,138	1,662,627	6,320	0	0
DISTRIBUTION	RB_GUP_EPIS_D	18,979,469	12,351,355	826,536	1,973,913	2,080,514	616,819	24,061	18,174	976,203	111,894
GENERAL PLANT	RB_GUP_EPIS_G	4,447,255	2,541,352	131,408	406,276	447,508	317,410	553,384	3,909	38,415	7,593
TOTAL DEPRECIATION EXPENSE		50,586,082	27,684,725	1,479,516	4,781,252	5,279,762	3,746,543	6,435,302	44,877	1,014,618	119,487
DEPRECIATION EXPENSE - ADJUSTMENT	FORMULA	12,957,354	6,803,362	337,111	1,204,007	1,345,345	1,079,473	1,992,025	11,334	164,963	19,733
ADJUSTED DEPRECIATION EXPENSE		63,543,436	34,488,088	1,816,626	5,985,259	6,625,108	4,826,017	8,427,327	56,211	1,179,582	139,220
TAXES OTHER THAN INCOME											
FEDERAL INSURANCE TAX	LABOR_M	2,856,586	1,632,375	84,407	260,961	287,446	203,881	355,453	2,511	24,675	4,877
FEDERAL UNEMPLOYMENT EXCISE TAX	LABOR_M	27,478	15,702	812	2,510	2,765	1,961	3,419	24	237	47
FEDERAL EXCISE TAX	LABOR_M	9,727	5,558	287	889	979	694	1,210	9	84	17
KENTUCKY SALES & USE TAX	TDPLANT	(566,333)	(323,056)	(18,646)	(54,998)	(59,993)	(36,382)	(54,435)	(511)	(16,428)	(1,883)
KENTUCKY R/E PRS & PROPERTY TAX	RB_GUP	9,181,190	4,936,456	258,938	863,179	956,853	711,155	1,256,353	8,094	170,401	19,761
LOUISIANA REAL & PERSONAL PROPERTY TAX	RB_GUP	199	107	6	19	21	15	27	0	4	0
KENTUCKY UNEMPLOYMENT TAX	LABOR_M	38,434	21,963	1,136	3,511	3,867	2,743	4,782	34	332	66
KENTUCKY PSC MAINTENANCE TAX	REVSALES	690,213	269,036	19,740	70,607	78,620	76,068	164,898	793	8,907	1,543
KENTUCKY MUNICIPAL LICENSE TAX	RB_GUP	99	53	3	9	10	8	14	0	2	0
KENTUCKY LICENSE TAX	RB_GUP	114	61	3	11	12	9	16	0	2	0
OHIO GROSS RECEIPTS TAX	REVSALES	222,171	86,599	6,354	22,728	25,307	24,485	53,079	255	2,867	497
OHIO FRANCHISE TAX	PROD_DEMAND	18,414	8,705	354	1,629	1,867	1,894	3,949	16	0	0
WEST VIRGINIA REAL & PERSONAL PROPERTY TAX	RB_GUP	954	513	27	90	99	74	131	1	18	2
WEST VIRGINIA UNEMPLOYMENT TAX	LABOR_M	1,620	926	48	148	163	116	202	1	14	3
WEST VIRGINIA FRANCHISE TAX	LABOR_M	(39,839)	(22,766)	(1,177)	(3,639)	(4,009)	(2,843)	(4,957)	(35)	(344)	(68)
WEST VIRGINIA LICENSE TAX	LABOR_M	55	31	2	5	6	4	7	0	0	0
PENNSYLVANIA LICENSE TAX	PROD_DEMAND	39	18	1	3	4	4	8	0	0	0
FRINGE BENEFIT LOADING FICA	LABOR_M	(1,111,545)	(635,184)	(32,844)	(101,544)	(111,850)	(79,333)	(138,313)	(977)	(9,601)	(1,898)
FRINGE BENEFIT LOADING FUT	LABOR_M	(11,724)	(6,700)	(346)	(1,071)	(1,180)	(837)	(1,459)	(10)	(101)	(20)
FRINGE BENEFIT LOADING SUT	LABOR_M	(12,498)	-7,142	(369)	(1,142)	(1,258)	(892)	(1,555)	(11)	(108)	(21)
R/E PRS FRANCHISE - CARRS TAX	RB_GUP	(51,723)	(27,810)	(1,459)	(4,863)	(5,391)	(4,006)	(7,078)	(46)	(960)	(111)
TOTAL TAXES OTHER THAN INCOME		11,253,631	5,955,448	317,275	1,059,042	1,174,340	898,817	1,635,751	10,147	180,001	22,811
TAXES OTHER THAN INCOME TAXES - ADJUSTMENT	FORMULA	220,301	111,485	6,310	21,060	23,340	18,682	35,547	210	3,211	455
ADJUSTED TAXES OTHER THAN INCOME TAX		11,473,932	6,066,933	323,585	1,080,102	1,197,680	917,500	1,671,298	10,357	183,212	23,265
TOTAL OPERATING REVENUE		521,797,305	204,638,731	15,058,906	53,033,456	60,336,427	55,421,580	124,693,344	593,343	6,861,076	1,160,441
TOTAL OPERATING EXPENSE BEFORE TAXES		531,011,545	244,656,173	12,853,238	46,811,179	56,088,293	50,745,001	113,481,908	517,793	5,194,241	663,719
GROSS OPERATING INCOME	FORMULA	(9,214,240)	(40,017,442)	2,205,668	6,222,277	4,248,134	4,676,580	11,211,436	75,550	1,666,836	496,722
INTEREST CHARGE TAX	RATEBASE	(37,443,850)	(19,786,379)	(1,061,010)	(3,515,799)	(3,967,910)	(2,938,654)	(5,320,658)	(34,480)	(732,412)	(86,546)
INTEREST SYNCHRONIZATION TAX	RATEBASE	2,732,876	1,444,128	77,439	256,604	289,602	214,481	388,333	2,517	53,456	6,317
NET OPER INCOME BEFORE INCOME TAX	FORMULA	(43,925,214)	(58,359,693)	1,222,097	2,963,082	569,826	1,952,406	6,279,111	43,586	987,879	416,492

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
INCOME TAXES											
SCHEDULE M INCOME ADJUSTMENTS											
BOOK VS TAX DEPRECIATION NORMALIZED	RB_GUP	(33,837,720)	(18,193,547)	(954,328)	(3,181,287)	(3,526,530)	(2,620,995)	(4,630,350)	(29,831)	(628,023)	(72,829)
BOOK VS TAX DEPRECIATION FLOWTHRU	RB_GUP	8,247,102	4,434,224	232,594	775,360	859,504	638,802	1,128,533	7,271	153,065	17,750
AOFUDC - HR/J	BULK_TRANS	11,364	5,372	218	1,006	1,152	1,169	2,437	10	0	0
ABFUDC	RB_CWIP	(807,411)	(415,152)	(20,378)	(74,366)	(83,337)	(69,957)	(132,283)	(698)	(10,071)	(1,167)
ABFUDC - HR/J	BULK_TRANS	22,044	10,421	424	1,951	2,235	2,268	4,728	19	0	0
SEC 481 PENSIONS/OPEB ADJUSTMENT	LABOR_M	(117)	(67)	(3)	(11)	(12)	(8)	(15)	(0)	(1)	(0)
INTEREST CAPITALIZATION	RB_GUP	1,565,806	841,888	44,161	147,211	163,187	121,284	214,265	1,380	29,061	3,370
DEFERRED FUEL	FUELREV	21,616,789	7,446,174	415,351	1,758,876	2,252,349	2,745,072	6,817,960	23,650	131,599	25,756
PROVISION FOR POSSIBLE REVENUE REFUNDS	REV	(704,906)	(276,177)	(20,328)	(71,641)	(81,516)	(74,946)	(168,702)	(802)	(9,228)	(1,564)
PERCENT REPAIR ALLOWANCE	RB_GUP	(1,783,802)	(959,098)	(50,309)	(167,706)	(185,906)	(138,169)	(244,095)	(1,573)	(33,107)	(3,839)
BOOK/TAX UNIT OF PROPERTY	RB_GUP	(3,603,276)	(1,937,376)	(101,623)	(338,766)	(375,529)	(279,102)	(493,072)	(3,177)	(66,876)	(7,755)
BOOK/TAX UNIT OF PROPERTY - SEC 481	RB_GUP	(27,693,495)	(14,889,978)	(781,042)	(2,603,632)	(2,886,185)	(2,145,077)	(3,789,575)	(24,414)	(513,987)	(59,605)
TAX AMORTIZATION OF POLLUTION CONTROL	PROD_DEMAND	2,724,318	1,287,920	52,343	241,067	276,188	280,236	584,270	2,294	0	0
CAPITALIZED RELOCATION COSTS	RB_GUP	(175,409)	(94,312)	(4,947)	(16,491)	(18,281)	(13,587)	(24,003)	(155)	(3,256)	(378)
MTM BOOK GAIN ABOVE THE LINE TAX DEFERRAL	PROD_ENERGY	(15,542,306)	(5,491,917)	(306,564)	(1,295,001)	(1,646,458)	(1,928,107)	(4,740,371)	(17,467)	(97,367)	(19,055)
MARK & SPREAD DEFL -283 A/L	PROD_ENERGY	10,225,186	3,613,098	201,687	851,973	1,083,194	1,268,489	3,118,661	11,491	64,057	12,536
MARK & SPREAD DEFL -190 A/L	PROD_ENERGY	(9,599,748)	(3,392,098)	(189,350)	(799,861)	(1,016,939)	(1,190,900)	(2,927,903)	(10,788)	(60,139)	(11,769)
PROVISION FOR WORKERS COMP	LABOR_M	(62,124)	(35,500)	(1,836)	(5,675)	(6,251)	(4,434)	(7,730)	(55)	(537)	(106)
ACCRUED BOOK PENSION EXPENSE	LABOR_M	3,441,009	1,966,340	101,675	314,351	346,254	245,592	428,174	3,024	29,723	5,875
ACCURED BOOK PENSION COSTS - SFAS 158	LABOR_M	(1,093,177)	(624,688)	(32,301)	(99,866)	(110,002)	(78,022)	(136,027)	(961)	(9,443)	(1,866)
SUPPLEMENTAL EXECUTIVE RETIREMENT	LABOR_M	3,391	1,938	100	310	341	242	422	3	29	6
ACCRUED SUPPLEMENTAL EXEC RETIREMENT COSTS SFAS 158	LABOR_M	(1,798)	(1,027)	(53)	(164)	(181)	(128)	(224)	(2)	(16)	(3)
ACCRUED BOOK SUPPLEMENTAL SAVINGS PLAN EXP	LABOR_M	98,892	56,511	2,922	9,034	9,951	7,058	12,305	87	854	169
ACCRUED PSI PLAN EXPENSES	LABOR_M	(386,625)	(220,934)	(11,424)	(35,320)	(38,904)	(27,594)	(48,109)	(340)	(3,340)	(660)
BOOK PROVISION UNCOLLECTIBLE ACCOUNTS	CUST_TOTAL	(4,520,982)	(2,903,386)	(455,611)	(156,232)	(17,364)	(1,757)	(363)	(404)	(984,735)	(1,131)
PROVISION FOR TRADING CREDIT RISK ABOVE THE LINE	PROD_ENERGY	104,118	36,790	2,054	8,675	11,030	12,916	31,756	117	652	128
PROVISION FOR FAS 157 A/L	PROD_ENERGY	38,284	13,528	755	3,190	4,056	4,749	11,677	43	240	47
VACATION PAY SEC 481	LABOR_M	131,477	75,132	3,885	12,011	13,230	9,384	16,360	116	1,136	224
ACCRUED STATE INTEREST EXPENSE	REV	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
ACCRUED LONG TERM INTEREST EXPENSE - FIN 48	REV	260,839	102,195	7,522	26,510	30,164	27,733	62,425	297	3,415	579
REG ASSET ON DEFERRED RTO COSTS	TRANS_TOTAL	147,454	68,782	2,828	13,005	14,917	15,530	32,269	123	0	0
FEDERAL MITIGATION PROGRAMS	PROD_ENERGY	(426,072)	(150,554)	(8,404)	(35,501)	(45,135)	(52,857)	(129,951)	(479)	(2,669)	(522)
STATE MITIGATION PROGRAMS	PROD_ENERGY	(630,761)	(222,881)	(12,441)	(52,556)	(66,819)	(78,249)	(192,381)	(709)	(3,951)	(773)
DEFERRED BOOK CONTRACT REVENUE	REV	(13,380)	(5,242)	(386)	(1,360)	(1,547)	(1,423)	(3,202)	(15)	(175)	(30)
DEFERRED DEMAND SIDE MANAGEMENT EXPENSE	LABOR_M	24,873	14,213	735	2,272	2,503	1,775	3,095	22	215	42
BOOK > TAX BASIS - EMA A/C 283	PROD_ENERGY	214,244	75,704	4,226	17,851	22,696	26,578	65,344	241	1,342	263
DEFERRED TAX GAIN EPA AUCTION	PROD_ENERGY	(38,059)	(13,448)	(751)	(3,171)	(4,032)	(4,721)	(11,606)	(43)	(238)	(47)
ADVANCE RENTAL INCOME	REV_OTHER	(8,933)	(5,690)	(376)	(1,041)	(997)	(334)	(283)	(8)	(185)	(21)
REG LIABILITY UNREALIZED MTM GAIN DEFERRAL	PROD_ENERGY	3,168,780	1,119,697	62,503	264,026	335,681	393,104	966,471	3,561	19,851	3,885
REG ASSET SFAS 158 PENSIONS	LABOR_M	1,093,177	624,688	32,301	99,866	110,002	78,022	136,027	961	9,443	1,866
REG ASSET SFAS 158 SERP	LABOR_M	1,798	1,027	53	164	181	128	224	2	16	3
REG ASSET SFAS 158 OPEB	LABOR_M	1,179,816	674,197	34,861	107,781	118,720	84,206	146,808	1,037	10,191	2,014
CAPITALIZED SOFTWARE COSTS TAX	RB_GUP	(764)	(411)	(22)	(72)	(80)	(59)	(105)	(1)	(14)	(2)
BOOK LEASES CAPITALIZED FOR TAX	RB_GUP	(71,801)	(38,605)	(2,025)	(6,750)	(7,483)	(5,562)	(9,825)	(63)	(1,333)	(155)
CAPITALIZED SOFTWARE COSTS BOOK	RB_GUP	1,331,392	715,850	37,549	125,172	138,756	103,127	182,188	1,174	24,710	2,866
BOOK AMORTIZATION LOSS REAQUIRED DEBT	RB_GUP	33,346	17,929	940	3,135	3,475	2,583	4,563	29	619	72
ACCRUED SFAS 106 POST RETIREMENT EXPENSE	LABOR_M	618,802	353,610	18,284	56,530	62,267	44,165	76,999	544	5,345	1,056
SFAS 106 POST RETIREMENT MEDICARE BENEFITS	LABOR_M	(851,119)	(486,366)	(25,149)	(77,753)	(85,644)	(60,746)	(105,907)	(748)	(7,352)	(1,453)
ACCRUED OPEB COSTS SFAS 158	LABOR_M	(1,179,816)	(674,197)	(34,861)	(107,781)	(118,720)	(84,206)	(146,808)	(1,037)	(10,191)	(2,014)
ACCRUED SFAS 112 POST EMPLOYMENT BENEFITS	LABOR_M	(359,347)	(205,346)	(10,618)	(32,828)	(36,160)	(25,647)	(44,715)	(316)	(3,104)	(614)
ACCRUED BOOK ARO EXPENSE SFAS 143	RB_GUP	2,852,343	1,533,621	80,445	268,166	297,268	220,936	390,314	2,515	52,939	6,139
ACCRUED SALES & USE TAX RESERVE	REV	(1,511,166)	(592,064)	(43,578)	(153,584)	(174,753)	(160,672)	(361,661)	(1,719)	(19,783)	(3,352)
ACCRUED SIT TAX RESERVE - LONG TERM FIN 48	REV	51,396	20,137	1,482	5,224	5,943	5,465	12,300	58	673	114
NON TAXABLE DEFERRED COMPENSATION CSV EARN	LABOR_M	34,434	19,677	1,017	3,146	3,465	2,458	4,285	30	297	59
NONDEDUCTIBLE MEALS & TRAVEL EXPENSE	LABOR_M	82,713	47,266	2,444	7,556	8,323	5,903	10,292	73	714	141
FIN 48 DSIT	REV	(43,069)	(16,874)	(1,242)	(4,377)	(4,981)	(4,579)	(10,308)	(49)	(564)	(95)
REMOVAL COSTS	RB_GUP	(8,077,641)	(4,343,110)	(227,814)	(759,428)	(841,843)	(625,676)	(1,105,344)	(7,121)	(149,920)	(17,386)
BOOK DEFFERAL MERGER COSTS	REV	(32,666)	(12,798)	(942)	(3,320)	(3,778)	(3,473)	(7,818)	(37)	(428)	(72)
REG ASSET ACCRUED SFAS 112	LABOR_M	359,347	205,346	10,618	32,828	36,160	25,647	44,715	316	3,104	614
1991 - 1996 IRS AUDIT SETTLEMENT	REV	(26,075)	(10,216)	(752)	(2,650)	(3,015)	(2,772)	(6,240)	(30)	(341)	(58)
TOTAL SCHEDULE M ADJUSTMENTS - PERBOOKS		(53,399,032)	(30,829,784)	(1,943,480)	(4,929,944)	(5,175,190)	(3,309,140)	(4,969,111)	(42,553)	(2,077,082)	(122,748)
ADJUSTMENTS TO PERBOOKS SCHEDULE M		27,448,160	13,060,289	703,659	2,495,171	2,909,506	2,538,821	5,284,220	27,083	375,111	54,299

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
WEST VIRGINIA STATE TAXABLE INCOME	FORMULA	(69,876,086)	(76,129,188)	(17,724)	528,309	(1,695,858)	1,182,087	6,594,220	28,116	(714,091)	348,044
BONUS DEPRECIATION ADJUSTMENT FOR STATE	RB_GUP	22,637,800	12,171,679	638,455	2,128,316	2,359,287	1,753,474	3,097,754	19,957	420,154	48,723
KENTUCKY STATE TAXABLE INCOME	FORMULA	(47,238,286)	(63,957,509)	620,731	2,656,625	663,428	2,935,561	9,691,974	48,074	(293,937)	396,767
STATE INCOME TAX KENTUCKY	FORMULA	(2,834,297)	(3,837,451)	37,244	159,397	39,806	176,134	581,518	2,884	(17,636)	23,806
STATE INCOME TAX WEST VIRGINIA	FORMULA	(159,457)	(173,727)	(40)	1,206	(3,870)	2,698	15,048	64	(1,630)	794
TOTAL STATE INCOME TAXES		(2,993,754)	(4,011,177)	37,203	160,603	35,936	178,831	596,566	2,949	(19,266)	24,600
TAXABLE OPERATING INCOME	FORMULA	(66,882,332)	(72,118,011)	(54,928)	367,706	(1,731,794)	1,003,256	5,997,653	25,168	(694,825)	323,444
GROSS CURRENT FIT	FORMULA	(23,408,816)	(25,241,304)	(19,225)	128,697	(606,128)	351,139	2,099,179	8,809	(243,189)	113,205
FEEDBACK PRIOR ITC NORMALIZATION TAX	RB_GUP	(818,986)	(440,345)	(23,098)	(76,998)	(85,354)	(63,437)	(112,070)	(722)	(15,200)	(1,763)
FEDERAL INCOME TAX - ITC - ADJUSTMENT		292,039	157,021	8,236	27,456	30,436	22,621	39,963	257	5,420	629
CURRENT FIT AND ITC	FORMULA	(23,935,763)	(25,524,628)	(34,086)	79,156	(661,046)	310,323	2,027,071	8,344	(252,969)	112,071
DEFERRED FIT - CURRENT YEAR											
DIFIT FOR BOOK VS TAX DEPRECIATION NORMALIZED	RB_GUP	11,706,400	6,294,187	330,156	1,100,589	1,220,028	906,752	1,601,903	10,320	217,269	25,196
DFIT ABFUDC	RB_CWIP	282,595	145,304	7,132	26,028	29,168	24,485	46,299	244	3,525	409
WSEC 482 PENSION/OPEB ADJUSTMENT	LABOR_M	41	23	1	4	4	3	5	0	0	0
INTEREST CAPITALIZATION	RB_GUP	(548,032)	(294,661)	(15,456)	(51,524)	(57,115)	(42,449)	(74,993)	(483)	(10,171)	(1,180)
DEFERRED FUEL EXPENSE	FUELREV	(7,565,876)	(2,606,161)	(145,373)	(615,607)	(788,322)	(960,775)	(2,386,286)	(8,278)	(46,060)	(9,015)
PROVISION FOR POSSIBLE REVENUE REFUNDS	REV	246,717	96,662	7,115	25,074	28,531	26,232	59,046	281	3,230	547
PERCENT REPAIR ALLOWANCE	RB_GUP	624,331	335,684	17,608	58,697	65,067	48,359	85,433	550	11,587	1,344
BOOK/TAX UNIT OF PROPERTY	RB_GUP	1,261,147	678,082	35,568	118,568	131,435	97,686	172,575	1,112	23,407	2,714
BOOK/TAX UNIT OF PROPERTY - SEC 481	RB_GUP	9,692,723	5,211,492	273,365	911,271	1,010,165	750,777	1,326,351	8,545	179,895	20,862
TAX AMORTIZATION POLLUTION CONTROL	PROD_DEMAND	(953,511)	(450,772)	(18,320)	(84,374)	(96,666)	(98,083)	(204,494)	(803)	0	0
CAPITALIZED RELOCATION COSTS	RB_GUP	61,393	33,009	1,731	5,772	6,398	4,755	8,401	54	1,139	132
MTM BOOK GAIN ABOVE THE LINE TAX DEFERRAL	PROD_ENERGY	5,439,807	1,922,171	107,297	453,250	576,260	674,837	1,659,130	6,113	34,078	6,669
MARK & SPREAD DEFL -283 A/L	PROD_ENERGY	(3,578,816)	(1,264,585)	(70,590)	(298,191)	(379,118)	(443,971)	(1,091,531)	(4,022)	(22,420)	(4,388)
MARK & SPREAD DEFL -190 A/L	PROD_ENERGY	3,359,913	1,187,235	66,273	279,951	355,929	416,815	1,024,766	3,776	21,049	4,119
PROVISION FOR WORKERS COMP	LABOR_M	21,743	12,425	642	1,986	2,188	1,552	2,706	19	188	37
ACCRUED BOOK PENSION EXPENSE	LABOR_M	(1,204,352)	(688,218)	(35,586)	(110,023)	(121,189)	(85,957)	(149,861)	(1,059)	(10,403)	(2,056)
ACCURED BOOK PENSION COSTS - SFAS 158	LABOR_M	382,612	218,641	11,305	34,953	38,501	27,308	47,609	336	3,305	653
SUPPLEMENTAL EXECUTIVE RETIREMENT	LABOR_M	(1,187)	(678)	(35)	(108)	(119)	(85)	(148)	(1)	(10)	(2)
ACCRUED SUPPLEMENTAL EXEC RETIREMENT COSTS SFAS 158	LABOR_M	629	359	19	57	63	45	78	1	5	1
ACCRUED BOOK SUPPLEMENTAL SAVINGS PLAN EXP	LABOR_M	(34,612)	(19,779)	(1,023)	(3,162)	(3,483)	(2,470)	(4,307)	(30)	(299)	(59)
ACCRUED PSI PLAN EXPENSES	LABOR_M	135,318	77,326	3,998	12,362	13,616	9,658	16,838	119	1,169	231
BOOK PROVISION UNCOLLECTIBLE ACCOUNTS	CUST_TOTAL	1,582,343	1,016,185	159,464	54,681	6,077	615	127	141	344,657	396
ACCRUED COMPANYWIDE INCENTIVE PLAN	LABOR_M	1	1	0	0	0	0	0	0	0	0
PROVISION FOR TRADING CREDIT RISK ABOVE THE LINE	PROD_ENERGY	(36,442)	(12,877)	(719)	(3,036)	(3,860)	(4,521)	(11,115)	(41)	(228)	(45)
PROVISION FOR FAS 157 A/L	PROD_ENERGY	(13,400)	(4,735)	(264)	(1,117)	(1,420)	(1,662)	(4,087)	(15)	(84)	(16)
ACCRUED BOOK VACATION PAY	LABOR_M	(46,017)	(26,296)	(1,360)	(4,204)	(4,630)	(3,284)	(5,726)	(40)	(397)	(79)
ACCRUED LONG TERM INTEREST EXPENSE - FIN 48	REV	(91,294)	(35,768)	(2,633)	(9,278)	(10,557)	(9,707)	(21,849)	(104)	(1,195)	(203)
REG ASSET ON DEFERRED RTO COSTS	TRANS_TOTAL	(51,609)	(24,074)	(990)	(4,552)	(5,221)	(5,435)	(11,294)	(43)	0	0
FEDERAL MITIGATION PROGRAMS	PROD_ENERGY	149,126	52,694	2,941	12,425	15,798	18,500	45,483	168	934	183
STATE MITIGATION PROGRAMS	PROD_ENERGY	220,767	78,009	4,355	18,395	23,387	27,387	67,333	248	1,383	271
DEFERRED BOOK CONTRACT REVENUE	REV	4,683	1,835	135	476	542	498	1,121	5	61	10
DEFERRED DEMAND SIDE MANAGEMENT EXPENSE	LABOR_M	(8,705)	(4,974)	(257)	(795)	(876)	(621)	(1,083)	(8)	(75)	(15)
BOOK > TAX BASIS - EMA A/C 283	PROD_ENERGY	(74,985)	(26,496)	(1,479)	(6,248)	(7,943)	(9,302)	(22,870)	(84)	(470)	(92)
DEFERRED TAX GAIN EPA AUCTION	PROD_ENERGY	13,321	4,707	263	1,110	1,411	1,653	4,063	15	83	16
ADVANCE RENTAL INCOME	REV_OTHER	3,127	1,992	131	365	349	117	99	3	65	7
REG ASSET UNREAL MTM GAIN DEFERRAL	PROD_ENERGY	(1,109,073)	(391,894)	(21,876)	(92,409)	(117,488)	(137,586)	(338,265)	(1,246)	(6,948)	(1,360)
REG ASSET SFAS 158 PENSIONS	LABOR_M	(382,612)	(218,641)	(11,305)	(34,953)	(38,501)	(27,308)	(47,609)	(336)	(3,305)	(653)
REG ASSET SFAS 158 SERP	LABOR_M	(629)	(359)	(19)	(57)	(63)	(45)	(78)	(1)	(5)	(1)
REG ASSET SFAS 158 OPEB	LABOR_M	(412,935)	(235,969)	(12,201)	(37,723)	(41,552)	(29,472)	(51,383)	(363)	(3,567)	(705)
CAPITALIZED SOFTWARE COST TAX	RB_GUP	268	144	8	25	28	21	37	0	5	1
BOOK LEASES CAPITALIZED FOR TAX	RB_GUP	25,131	13,512	709	2,363	2,619	1,947	3,439	22	466	54
CAPITALIZED SOFTWARE COST BOOK	RB_GUP	(465,987)	(250,548)	(13,142)	(43,810)	(48,565)	(36,094)	(63,766)	(411)	(8,649)	(1,003)
BOOK AMORTIZATION LOSS REAQUIRED DEBT	RB_GUP	(11,671)	(6,275)	(329)	(1,097)	(1,216)	(904)	(1,597)	(10)	(217)	(25)
ACCRUED SFAS 106 POST RETIREMENT EXPENSE	LABOR_M	(216,581)	(123,764)	(6,400)	(19,786)	(21,794)	(15,458)	(26,950)	(190)	(1,871)	(370)
ACCRUED OPEB COSTS SFAS 158	LABOR_M	412,936	235,969	12,201	37,723	41,552	29,472	51,383	363	3,567	705
ACCRUED SFAS 112 POST EMPLOYMENT BENEFITS	LABOR_M	125,773	71,872	3,716	11,490	12,656	8,977	15,650	111	1,086	215
ACCRUED BOOK ARO EXPENSE SFAS 143	RB_GUP	(998,320)	(536,767)	(28,156)	(93,858)	(104,044)	(77,328)	(136,610)	(880)	(18,529)	(2,149)
ACCRUED SALES & USE TAX RESERVE	REV	528,909	207,223	15,252	53,754	61,164	56,235	126,581	602	6,924	1,173
ACCRUED SIT TAX RESERVE - LONG TERM FIN 48	REV	(17,989)	(7,048)	(519)	(1,828)	(2,080)	(1,913)	(4,305)	(20)	(236)	(40)
FIN 48 DSIT	REV	15,074	5,906	435	1,532	1,743	1,603	3,608	17	197	33
BOOK DEFFERAL MERGER COSTS	REV	11,433	4,479	330	1,162	1,322	1,216	2,736	13	150	25
REG ASSET ACCRUED SFAS 112	LABOR_M	(125,772)	(71,871)	(3,716)	(11,490)	(12,656)	(8,977)	(15,650)	(111)	(1,086)	(215)
1991 - 1996 IRS AUDIT SETTLEMENT	REV	9,127	3,576	263	928	1,055	970	2,184	10	119	20
FEDERAL INCOME TAX - DEFERRED - ADJUSTMENT		(8,016,836)	(3,717,681)	(201,640)	(723,950)	(852,684)	(764,843)	(1,630,127)	(8,078)	(102,201)	(15,631)
TOTAL CURRENT YEAR DFIT		10,350,145	6,889,812	469,027	971,812	925,893	370,223	69,001	6,531	621,120	26,725

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	METHOD	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP-TOD	MW	OL	SL
DEFERRED FIT - PRIOR YEAR											
GAIN/LOSS ON ACRS/MACRS PROPERTY	RB_GUP	(918,515)	(493,859)	(25,905)	(86,355)	(95,727)	(71,146)	(125,690)	(810)	(17,047)	(1,977)
ABFUDC	RB_CWIP	(181,758)	(93,456)	(4,587)	(16,741)	(18,760)	(15,748)	(29,778)	(157)	(2,267)	(263)
ABFUDC HRJ POST-IN SERVE	BULK_TRANS	(7,449)	(3,522)	(143)	(659)	(755)	(766)	(1,598)	(6)	0	0
ABFUDC - HRJ (TC)	BULK_TRANS	(319,206)	(150,905)	(6,133)	(28,246)	(32,361)	(32,835)	(68,458)	(269)	0	0
TAXES CAPITALIZED	LABOR_M	(46,737)	(26,708)	(1,381)	(4,270)	(4,703)	(3,336)	(5,816)	(41)	(404)	(80)
PENSIONS CAPITALIZED	LABOR_M	(5,793)	(3,310)	(171)	(529)	(583)	(413)	(721)	(5)	(50)	(10)
SAVING PLAN CAPITALIZED	LABOR_M	(3,358)	(1,919)	(99)	(307)	(338)	(240)	(418)	(3)	(29)	(6)
INTEREST CAPITALIZED	RB_GUP	257,373	138,382	7,259	24,197	26,823	19,936	35,219	227	4,777	554
ADR REPAIR ALLOWANCE	RB_GUP	(692,281)	(372,219)	(19,524)	(65,085)	(72,149)	(53,623)	(94,732)	(610)	(12,849)	(1,490)
CAPITALIZED RELOCATION COSTS	RB_GUP	293,928	158,036	8,290	27,634	30,633	22,767	40,221	259	5,455	633
TOTAL PRIOR YEAR DFIT		(1,623,796)	(849,478)	(42,396)	(150,361)	(167,919)	(135,404)	(251,770)	(1,415)	(22,414)	(2,639)
FEDERAL INCOME TAXES	FORMULA	(15,209,414)	(19,484,293)	392,545	900,607	96,928	545,142	1,844,303	13,460	345,737	136,158
TOTAL INCOME TAXES		(18,203,168)	(23,495,471)	429,749	1,061,210	132,864	723,973	2,440,869	16,408	326,471	160,758
TOTAL EXPENSES	FORMULA	512,808,377	221,160,702	13,282,987	47,872,389	56,221,157	51,468,974	115,922,777	534,201	5,520,712	824,477
NET OPERATING INCOME	FORMULA	8,988,926	(16,521,971)	1,775,919	5,161,067	4,115,270	3,952,607	8,770,567	59,141	1,340,364	335,964
AFUDC OFFSET											
PRODUCTION	PROD_DEMAND	554,942	262,349	10,662	49,105	56,259	57,084	119,015	467	0	0
TRANSMISSION	RB_GUP_EPIS_T	277,698	129,543	5,326	24,493	28,093	29,244	60,767	231	0	0
DISTRIBUTION	RB_GUP_EPIS_D	164,723	107,198	7,174	17,132	18,057	5,353	209	158	8,472	971
GENERAL	LABOR_M	26,898	15,371	795	2,457	2,707	1,920	3,347	24	232	46
AFUDC OFFSET		1,024,261	514,460	23,957	93,187	105,115	93,601	183,339	880	8,705	1,017
AFUDC OFFSET - ADJUSTMENT		1,190,864	598,141	27,854	108,344	122,213	108,826	213,160	1,023	10,121	1,182
ADJUSTED NET OPERATING INCOME	FORMULA	11,204,053	(15,409,370)	1,827,730	5,362,597	4,342,599	4,155,034	9,167,065	61,044	1,359,190	338,163

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

ALLOCATION METHOD	FUNCTIONAL FACTOR	TOTAL RETAIL	RS	SGS	MGS	LGS	QP	CIP_TOD	MW	OL	SL
AFUDC_OFF	PRODUCTION	0.5532558	0.2615515	0.0106298	0.0489561	0.0560883	0.0569104	0.1186537	0.0004659	0.0000000	0.0000000
	BULKTRAN	0.1882124	0.0889774	0.0036162	0.0166544	0.0190807	0.0193604	0.0403649	0.0001585	0.0000000	0.0000000
	SUBTRAN	0.0833784	0.0377108	0.0015931	0.0072992	0.0083940	0.0092432	0.0190705	0.0000674	0.0000000	0.0000000
	DISTPRI	0.0862909	0.0569196	0.0023550	0.0105929	0.0111099	0.0052136	0.0000000	0.0000999	0.0000000	0.0000000
	DISTSEC	0.0592612	0.0432040	0.0022171	0.0059830	0.0071630	0.0000316	0.0000000	0.0000620	0.0005064	0.0000942
	ENERGY	0.0022740	0.0008035	0.0000449	0.0001895	0.0002409	0.0002821	0.0006936	0.0000026	0.0000142	0.0000028
	CUSTOMER	0.0273274	0.0131078	0.0029334	0.0013044	0.0005488	0.0003430	0.0002133	0.0000026	0.0079780	0.0008960
	Total	1.0000000	0.5022746	0.0233895	0.0909795	0.1026256	0.0913842	0.1789961	0.0008589	0.0084986	0.0009930
BULK_TRANS	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	1.0000000	0.4727497	0.0192132	0.0884872	0.1013786	0.1028646	0.2144646	0.0008422	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4727497	0.0192132	0.0884872	0.1013786	0.1028646	0.2144646	0.0008422	0.0000000	0.0000000
CUST_902	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.7975641	0.1251570	0.0645058	0.0109151	0.0014476	0.0002995	0.0001109	0.0000000	0.0000000
	Total	1.0000000	0.7975641	0.1251570	0.0645058	0.0109151	0.0014476	0.0002995	0.0001109	0.0000000	0.0000000
CUST_903	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.7688785	0.0764781	0.0262249	0.0029148	0.0002947	0.0000609	0.0000677	0.1248906	0.0001899
	Total	1.0000000	0.7688785	0.0764781	0.0262249	0.0029148	0.0002947	0.0000609	0.0000677	0.1248906	0.0001899
CUST_DEP	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.7787425	0.0412488	0.0961286	0.0421900	0.0270141	0.0088213	0.0000000	0.0058546	0.0000000
	Total	1.0000000	0.7787425	0.0412488	0.0961286	0.0421900	0.0270141	0.0088213	0.0000000	0.0058546	0.0000000

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

CUST_TOTAL	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.6422026	0.1007771	0.0345570	0.0038407	0.0003885	0.0000804	0.0000893	0.2178144	0.0002501
	Total	1.0000000	0.6422026	0.1007771	0.0345570	0.0038407	0.0003885	0.0000804	0.0000893	0.2178144	0.0002501
DIST_CPD	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	1.0000000	0.6596250	0.0272917	0.1227580	0.1287494	0.0604186	0.0000000	0.0011574	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.6596250	0.0272917	0.1227580	0.1287494	0.0604186	0.0000000	0.0011574	0.0000000	0.0000000
DIST_METERS	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.4993288	0.2293275	0.1203371	0.0716245	0.0487719	0.0304012	0.0002090	0.0000000	0.0000000
	Total	1.0000000	0.4993288	0.2293275	0.1203371	0.0716245	0.0487719	0.0304012	0.0002090	0.0000000	0.0000000
DIST_OHLINES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6610000	0.4360121	0.0180398	0.0811430	0.0851033	0.0399367	0.0000000	0.0007651	0.0000000	0.0000000
	DISTSEC	0.3390000	0.2471458	0.0126827	0.0342254	0.0409756	0.0001808	0.0000000	0.0003545	0.0028966	0.0005386
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.6831579	0.0307225	0.1153684	0.1260789	0.0401174	0.0000000	0.0011196	0.0028966	0.0005386
DIST_OL	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	1.0000000	0.0000000
	Total	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	1.0000000	0.0000000

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

DIST_PCUST	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.6425239	0.1008275	0.0345028	0.0036728	0.0002100	0.0000000	0.0000894	0.2179234	0.0002502
	Total	1.0000000	0.6425239	0.1008275	0.0345028	0.0036728	0.0002100	0.0000000	0.0000894	0.2179234	0.0002502
DIST_POLES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.5620000	0.3707092	0.0153379	0.0689900	0.0723571	0.0339552	0.0000000	0.0006505	0.0000000	0.0000000
	DISTSEC	0.4380000	0.3193211	0.0163865	0.0442204	0.0529419	0.0002336	0.0000000	0.0004581	0.0037425	0.0006959
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.6900304	0.0317245	0.1132104	0.1252991	0.0341888	0.0000000	0.0011085	0.0037425	0.0006959
DIST_SERV	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.6431504	0.1009258	0.0341876	0.0032560	0.0000045	0.0000000	0.0000894	0.2181359	0.0002505
	Total	1.0000000	0.6431504	0.1009258	0.0341876	0.0032560	0.0000045	0.0000000	0.0000894	0.2181359	0.0002505
DIST_SL	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	1.0000000
	Total	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	1.0000000
DIST_TRANSF	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.2650000	0.1748006	0.0072323	0.0325309	0.0341186	0.0160109	0.0000000	0.0003067	0.0000000	0.0000000
	DISTSEC	0.7350000	0.5358471	0.0274979	0.0742055	0.0888409	0.0003920	0.0000000	0.0007687	0.0062802	0.0011678
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.7106477	0.0347302	0.1067363	0.1229595	0.0164029	0.0000000	0.0010754	0.0062802	0.0011678
DIST_UGLINES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6250000	0.4122656	0.0170573	0.0767237	0.0804684	0.0377616	0.0000000	0.0007234	0.0000000	0.0000000
	DISTSEC	0.3750000	0.2733914	0.0140296	0.0378599	0.0453270	0.0002000	0.0000000	0.0003922	0.0032042	0.0005958
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.6856570	0.0310869	0.1145837	0.1257954	0.0379616	0.0000000	0.0011156	0.0032042	0.0005958
EXP_OM_AG_REG	PRODUCTION	0.3849601	0.1201673	0.0068315	0.0337773	0.0392951	0.0521366	0.1323675	0.0003848	0.0000000	0.0000000
	BULKTRAN	0.2098965	0.0655203	0.0037248	0.0184168	0.0214253	0.0284271	0.0721724	0.0002098	0.0000000	0.0000000
	SUBTRAN	0.0921712	0.0276121	0.0016317	0.0080314	0.0094302	0.0134903	0.0318868	0.0000887	0.0000000	0.0000000
	DISTPRI	0.1590001	0.0886850	0.0051327	0.0247295	0.0257537	0.0144195	0.0000000	0.0002797	0.0000000	0.0000000
	DISTSEC	0.1036546	0.0674804	0.0048439	0.0139724	0.0161388	0.0000758	0.0000000	0.0001740	0.0007586	0.0002107
	ENERGY	0.0036538	0.0007716	0.0000602	0.0002732	0.0003526	0.0005384	0.0016364	0.0000044	0.0000131	0.0000038
	CUSTOMER	0.0466637	0.0195502	0.0063753	0.0030970	0.0015113	0.0011221	0.0008462	0.0000074	0.0121336	0.0020206
	Total	1.0000000	0.3897869	0.0286003	0.1022976	0.1139070	0.1102099	0.2389092	0.0011488	0.0129053	0.0022351
EXP_OM_CUSTACCT	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.9896043	0.0503014	0.0236892	0.0037506	0.0004814	0.0000994	0.0000444	(0.0680033)	0.0000323
	Total	1.0000000	0.9896043	0.0503014	0.0236892	0.0037506	0.0004814	0.0000994	0.0000444	(0.0680033)	0.0000323
EXP_OM_CUSTSERV	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.6422026	0.1007771	0.0345570	0.0038407	0.0003885	0.0000804	0.0000893	0.2178144	0.0002501
	Total	1.0000000	0.6422026	0.1007771	0.0345570	0.0038407	0.0003885	0.0000804	0.0000893	0.2178144	0.0002501
EXP_OM_DIST	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.5752849	0.3794723	0.0157005	0.0706208	0.0740676	0.0347579	0.0000000	0.0006659	0.0000000	0.0000000
	DISTSEC	0.3592706	0.2619240	0.0134411	0.0362719	0.0434257	0.0001916	0.0000000	0.0003757	0.0030698	0.0005708
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0654445	0.0238268	0.0083713	0.0041459	0.0022424	0.0014974	0.0009328	0.0000076	0.0207573	0.0036630
	Total	1.0000000	0.6652231	0.0375129	0.1110386	0.1197357	0.0364468	0.0009328	0.0010492	0.0238271	0.0042339

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

EXP_OM_SS	PRODUCTION	0.0571805	0.0270321	0.0010986	0.0050597	0.0057969	0.0058818	0.0122632	0.0000482	(0.0000000)	(0.0000000)
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.9428195	0.3331479	0.0185966	0.0785567	0.0998766	0.1169618	0.2875580	0.0010596	0.0059064	0.0011559
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.3601800	0.0196953	0.0836164	0.1056735	0.1228437	0.2998212	0.0011077	0.0059064	0.0011559
EXP_OM_TRAN	PRODUCTION	0.0007683	0.0003632	0.0000148	0.0000680	0.0000779	0.0000790	0.0001648	0.0000006	0.0000000	0.0000000
	BULKTRAN	0.6924676	0.3273638	0.0133045	0.0612745	0.0702014	0.0712304	0.1485097	0.0005832	0.0000000	0.0000000
	SUBTRAN	0.3067641	0.1387450	0.0058615	0.0268552	0.0308831	0.0340075	0.0701640	0.0002480	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4664720	0.0191807	0.0881978	0.1011624	0.1053169	0.2188385	0.0008318	0.0000000	0.0000000
EXP_OM	PRODUCTION	0.3057699	0.1445524	0.0058748	0.0270567	0.0309985	0.0314529	0.0655769	0.0002575	0.0000000	0.0000000
	BULKTRAN	0.0049268	0.0023291	0.0000947	0.0004360	0.0004995	0.0005068	0.0010567	0.0000041	0.0000000	0.0000000
	SUBTRAN	0.0021826	0.0009871	0.0000417	0.0001911	0.0002197	0.0002420	0.0004992	0.0000018	0.0000000	0.0000000
	DISTPRI	0.0699739	0.0461565	0.0019097	0.0085899	0.0090091	0.0042277	0.0000000	0.0000810	0.0000000	0.0000000
	DISTSEC	0.0436993	0.0318587	0.0016349	0.0044119	0.0052820	0.0000233	0.0000000	0.0000457	0.0003734	0.0000694
	ENERGY	0.5484336	0.1937906	0.0108176	0.0456960	0.0580977	0.0680361	0.1672711	0.0006163	0.0034357	0.0006724
	CUSTOMER	0.0250138	0.0178306	0.0021585	0.0009691	0.0003372	0.0001898	0.0001151	0.0000019	0.0029643	0.0004473
	Total	1.0000000	0.4375050	0.0225318	0.0873506	0.1044438	0.1046787	0.2345191	0.0010084	0.0067735	0.0011891
EXP_OTHTAX_PSC	PRODUCTION	0.3109668	0.0982492	0.0054678	0.0274315	0.0318371	0.0424559	0.1052171	0.0003053	0.0000022	0.0000006
	BULKTRAN	0.1884695	0.0596882	0.0033185	0.0166479	0.0192531	0.0257630	0.0636141	0.0001848	0.0000000	0.0000000
	SUBTRAN	0.0832745	0.0252018	0.0014565	0.0072746	0.0084902	0.0122794	0.0284937	0.0000783	0.0000000	0.0000000
	DISTPRI	0.1678936	0.0943554	0.0053414	0.0260639	0.0269457	0.0149007	0.0000000	0.0002867	0.0000000	0.0000000
	DISTSEC	0.1092263	0.0715200	0.0050215	0.0146652	0.0167916	0.0000773	0.0000000	0.0001776	0.0007639	0.0002092
	ENERGY	0.0926394	0.0201595	0.0015440	0.0070224	0.0090513	0.0135868	0.0407533	0.0001087	0.0003218	0.0000917
	CUSTOMER	0.0475298	0.0206128	0.0064507	0.0031921	0.0015379	0.0011468	0.0008310	0.0000073	0.0118174	0.0019337
	Total	1.0000000	0.3897869	0.0286003	0.1022976	0.1139070	0.1102099	0.2389092	0.0011488	0.0129053	0.0022351
FORT	PRODUCTION	1.0000000	0.6097919	0.0776748	0.1683812	0.0824828	0.0116823	0.0404363	0.0000000	0.0095508	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.6097919	0.0776748	0.1683812	0.0824828	0.0116823	0.0404363	0.0000000	0.0095508	0.0000000

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

FUELREV	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	1.0000000	0.3444625	0.0192143	0.0813662	0.1041944	0.1269880	0.3154011	0.0010941	0.0060878	0.0011915
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.3444625	0.0192143	0.0813662	0.1041944	0.1269880	0.3154011	0.0010941	0.0060878	0.0011915
LABOR_M	PRODUCTION	0.3983208	0.1883060	0.0076530	0.0352463	0.0403812	0.0409731	0.0854257	0.0003355	0.0000000	0.0000000
	BULKTRAN	0.0387519	0.0183199	0.0007445	0.0034290	0.0039286	0.0039862	0.0083109	0.0000326	0.0000000	0.0000000
	SUBTRAN	0.0171671	0.0077644	0.0003280	0.0015029	0.0017283	0.0019031	0.0039265	0.0000139	0.0000000	0.0000000
	DISTPRI	0.2167067	0.1429451	0.0059143	0.0266025	0.0279008	0.0130931	0.0000000	0.0002508	0.0000000	0.0000000
	DISTSEC	0.1353353	0.0986653	0.0050632	0.0136634	0.0163582	0.0000722	0.0000000	0.0001415	0.0011564	0.0002150
	ENERGY	0.0865921	0.0305976	0.0017080	0.0072149	0.0091730	0.0107422	0.0264104	0.0000973	0.0005425	0.0001062
	CUSTOMER	0.1071261	0.0848443	0.0081370	0.0036953	0.0011555	0.0006022	0.0003593	0.0000073	0.0069391	0.0013861
	Total	1.0000000	0.5714427	0.0295481	0.0913543	0.1006258	0.0713721	0.1244328	0.0008789	0.0086380	0.0017073
PROD_DEMAND	PRODUCTION	1.0000000	0.4727497	0.0192132	0.0884872	0.1013786	0.1028646	0.2144646	0.0008422	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4727497	0.0192132	0.0884872	0.1013786	0.1028646	0.2144646	0.0008422	0.0000000	0.0000000
PROD_ENERGY	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	1.0000000	0.3533528	0.0197245	0.0833210	0.1059340	0.1240554	0.3049979	0.0011238	0.0062646	0.0012260
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.3533528	0.0197245	0.0833210	0.1059340	0.1240554	0.3049979	0.0011238	0.0062646	0.0012260
PROP_INCR	PRODUCTION	1.0000000	0.5568667	0.0263231	0.0881494	0.1017635	0.0741136	0.1319945	0.0008532	0.0180410	0.0018951
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.5568667	0.0263231	0.0881494	0.1017635	0.0741136	0.1319945	0.0008532	0.0180410	0.0018951

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

RATEBASE	PRODUCTION	0.2852175	0.1331951	0.0054173	0.0251582	0.0292446	0.0296408	0.0623128	0.0002448	0.0000034	0.0000006
	BULKTRAN	0.1729695	0.0809184	0.0032878	0.0152676	0.0176935	0.0179793	0.0376748	0.0001481	0.0000000	0.0000000
	SUBTRAN	0.0764111	0.0341657	0.0014430	0.0066655	0.0077527	0.0085654	0.0177560	0.0000628	0.0000000	0.0000000
	DISTPRI	0.1947346	0.1279163	0.0052920	0.0239749	0.0254027	0.0119189	0.0000000	0.0002298	0.0000000	0.0000000
	DISTSEC	0.1334245	0.0969587	0.0049751	0.0135327	0.0163688	0.0000726	0.0000000	0.0001424	0.0011578	0.0002163
	ENERGY	0.0776792	0.0273300	0.0015297	0.0064402	0.0082907	0.0095422	0.0238767	0.0000871	0.0004877	0.0000948
	CUSTOMER	0.0595636	0.0279445	0.0063911	0.0028561	0.0012166	0.0007622	0.0004761	0.0000059	0.0179114	0.0019997
	Total	1.0000000	0.5284287	0.0283361	0.0938953	0.1059696	0.0784814	0.1420964	0.0009208	0.0195603	0.0023114
RB_CWIP	PRODUCTION	0.2231994	0.1055174	0.0042884	0.0197503	0.0226276	0.0229593	0.0478684	0.0001880	0.0000000	0.0000000
	BULKTRAN	0.3643637	0.1722528	0.0070006	0.0322415	0.0369387	0.0374801	0.0781431	0.0003069	0.0000000	0.0000000
	SUBTRAN	0.1614137	0.0730050	0.0030842	0.0141307	0.0162501	0.0178941	0.0369190	0.0001305	0.0000000	0.0000000
	DISTPRI	0.1245279	0.0821417	0.0033986	0.0152868	0.0160329	0.0075238	0.0000000	0.0001441	0.0000000	0.0000000
	DISTSEC	0.0857430	0.0625104	0.0032078	0.0086566	0.0103639	0.0000457	0.0000000	0.0000897	0.0007326	0.0001362
	ENERGY	0.0019497	0.0006889	0.0000385	0.0001624	0.0002065	0.0002419	0.0005946	0.0000022	0.0000122	0.0000024
	CUSTOMER	0.0388027	0.0180609	0.0042206	0.0018755	0.0007957	0.0004992	0.0003107	0.0000038	0.0117289	0.0013073
	Total	1.0000000	0.5141773	0.0252387	0.0921039	0.1032155	0.0866441	0.1638358	0.0008651	0.0124738	0.0014459
RB_GUP_EPIS_D	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.5011772	0.3305890	0.0136780	0.0615235	0.0645263	0.0302804	0.0000000	0.0005801	0.0000000	0.0000000
	DISTSEC	0.3463917	0.2525347	0.0129593	0.0349716	0.0418690	0.0001847	0.0000000	0.0003623	0.0029597	0.0005504
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.1524311	0.0676508	0.0169117	0.0075074	0.0032239	0.0020342	0.0012678	0.0000152	0.0484749	0.0053452
	Total	1.0000000	0.6507745	0.0435489	0.1040025	0.1096192	0.0324993	0.0012678	0.0009576	0.0514347	0.0058955
RB_GUP_EPIS_G	PRODUCTION	0.3983208	0.1883060	0.0076530	0.0352463	0.0403812	0.0409731	0.0854257	0.0003355	0.0000000	0.0000000
	BULKTRAN	0.0387519	0.0183199	0.0007445	0.0034290	0.0039286	0.0039862	0.0083109	0.0000326	0.0000000	0.0000000
	SUBTRAN	0.0171671	0.0077644	0.0003280	0.0015029	0.0017283	0.0019031	0.0039265	0.0000139	0.0000000	0.0000000
	DISTPRI	0.2167067	0.1429451	0.0059143	0.0266025	0.0279008	0.0130931	0.0000000	0.0002508	0.0000000	0.0000000
	DISTSEC	0.1353353	0.0986653	0.0050632	0.0136634	0.0163582	0.0000722	0.0000000	0.0001415	0.0011564	0.0002150
	ENERGY	0.0865921	0.0305976	0.0017080	0.0072149	0.0091730	0.0107422	0.0264104	0.0000973	0.0005425	0.0001062
	CUSTOMER	0.1071261	0.0848443	0.0081370	0.0036953	0.0011555	0.0006022	0.0003593	0.0000073	0.0069391	0.0013861
	Total	1.0000000	0.5714427	0.0295481	0.0913543	0.1006258	0.0713721	0.1244328	0.0008789	0.0086380	0.0017073
RB_GUP_EPIS_P	PRODUCTION	1.0000000	0.4727497	0.0192132	0.0884872	0.1013786	0.1028646	0.2144646	0.0008422	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4727497	0.0192132	0.0884872	0.1013786	0.1028646	0.2144646	0.0008422	0.0000000	0.0000000

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

RB_GUP_EPIS_T	PRODUCTION	0.0036812	0.0017403	0.0000707	0.0003257	0.0003732	0.0003787	0.0007895	0.0000031	0.0000000	0.0000000
	BULKTRAN	0.6904489	0.3264095	0.0132657	0.0610959	0.0699968	0.0710227	0.1480768	0.0005815	0.0000000	0.0000000
	SUBTRAN	0.3058699	0.1383405	0.0058444	0.0267770	0.0307930	0.0339083	0.0699594	0.0002473	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4664903	0.0191808	0.0881986	0.1011630	0.1053097	0.2188257	0.0008318	0.0000000	0.0000000
RB_GUP_EPIS	PRODUCTION	0.3506261	0.1657584	0.0067366	0.0310259	0.0355460	0.0360670	0.0751969	0.0002953	0.0000000	0.0000000
	BULKTRAN	0.1911761	0.0903785	0.0036731	0.0169166	0.0193812	0.0196653	0.0410005	0.0001610	0.0000000	0.0000000
	SUBTRAN	0.0842124	0.0380881	0.0016091	0.0073723	0.0084780	0.0093357	0.0192613	0.0000681	0.0000000	0.0000000
	DISTPRI	0.1854566	0.1223318	0.0050614	0.0227663	0.0238774	0.0112050	0.0000000	0.0002147	0.0000000	0.0000000
	DISTSEC	0.1276771	0.0930822	0.0047767	0.0128903	0.0154326	0.0000681	0.0000000	0.0001335	0.0010909	0.0002029
	ENERGY	0.0030121	0.0010643	0.0000594	0.0002510	0.0003191	0.0003737	0.0009187	0.0000034	0.0000189	0.0000037
	CUSTOMER	0.0578396	0.0269674	0.0062867	0.0027937	0.0011847	0.0007431	0.0004626	0.0000057	0.0174500	0.0019458
	Total	1.0000000	0.5376706	0.0282031	0.0940160	0.1042189	0.0774578	0.1368399	0.0008816	0.0185598	0.0021523
RB_GUP	PRODUCTION	0.3506261	0.1657584	0.0067366	0.0310259	0.0355460	0.0360670	0.0751969	0.0002953	0.0000000	0.0000000
	BULKTRAN	0.1911761	0.0903785	0.0036731	0.0169166	0.0193812	0.0196653	0.0410005	0.0001610	0.0000000	0.0000000
	SUBTRAN	0.0842124	0.0380881	0.0016091	0.0073723	0.0084780	0.0093357	0.0192613	0.0000681	0.0000000	0.0000000
	DISTPRI	0.1854566	0.1223318	0.0050614	0.0227663	0.0238774	0.0112050	0.0000000	0.0002147	0.0000000	0.0000000
	DISTSEC	0.1276771	0.0930822	0.0047767	0.0128903	0.0154326	0.0000681	0.0000000	0.0001335	0.0010909	0.0002029
	ENERGY	0.0030121	0.0010643	0.0000594	0.0002510	0.0003191	0.0003737	0.0009187	0.0000034	0.0000189	0.0000037
	CUSTOMER	0.0578396	0.0269674	0.0062867	0.0027937	0.0011847	0.0007431	0.0004626	0.0000057	0.0174500	0.0019458
	Total	1.0000000	0.5376706	0.0282031	0.0940160	0.1042189	0.0774578	0.1368399	0.0008816	0.0185598	0.0021523
REV_OTHER	PRODUCTION	0.1608003	0.0980547	0.0124901	0.0270757	0.0132633	0.0018785	0.0065022	0.0000000	0.0015358	0.0000000
	BULKTRAN	0.0043074	0.0020363	0.0000828	0.0003812	0.0004367	0.0004431	0.0009238	0.0000036	0.0000000	0.0000000
	SUBTRAN	0.0019082	0.0008630	0.0000365	0.0001670	0.0001921	0.0002115	0.0004364	0.0000015	0.0000000	0.0000000
	DISTPRI	0.4048908	0.2670761	0.0110502	0.0497036	0.0521294	0.0244629	0.0000000	0.0004686	0.0000000	0.0000000
	DISTSEC	0.3008906	0.2193624	0.0112570	0.0303779	0.0363692	0.0001605	0.0000000	0.0003147	0.0025710	0.0004781
	ENERGY	0.0766347	0.0270791	0.0015116	0.0063853	0.0081182	0.0095069	0.0233734	0.0000861	0.0004801	0.0000940
	CUSTOMER	0.0505680	0.0224427	0.0056103	0.0024905	0.0010695	0.0006748	0.0004206	0.0000051	0.0160812	0.0017732
	Total	1.0000000	0.6369144	0.0420384	0.1165812	0.1115784	0.0373383	0.0316564	0.0008796	0.0206680	0.0023452
REV_SALES	PRODUCTION	1.0000000	0.3863828	0.0285463	0.1013027	0.1157306	0.1078459	0.2439087	0.0011431	0.0129243	0.0022156
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.3863828	0.0285463	0.1013027	0.1157306	0.1078459	0.2439087	0.0011431	0.0129243	0.0022156

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

REV	PRODUCTION	0.9818790	0.3801568	0.0281996	0.0996999	0.1135180	0.1055577	0.2387824	0.0011184	0.0126784	0.0021678
	BULKTRAN	0.0000930	0.0000440	0.0000018	0.0000082	0.0000094	0.0000096	0.0000199	0.0000001	0.0000000	0.0000000
	SUBTRAN	0.0000412	0.0000186	0.0000008	0.0000036	0.0000041	0.0000046	0.0000094	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0087429	0.0057670	0.0002386	0.0010733	0.0011256	0.0005282	0.0000000	0.0000101	0.0000000	0.0000000
	DISTSEC	0.0064972	0.0047367	0.0002431	0.0006560	0.0007853	0.0000035	0.0000000	0.0000068	0.0000555	0.0000103
	ENERGY	0.0016548	0.0005847	0.0000326	0.0001379	0.0001753	0.0002053	0.0005047	0.0000019	0.0000104	0.0000020
	CUSTOMER	0.0010919	0.0004846	0.0001211	0.0000538	0.0000231	0.0000146	0.0000091	0.0000001	0.0003472	0.0000383
	Total	1.0000000	0.3917926	0.0288376	0.1016326	0.1156409	0.1063234	0.2393255	0.0011374	0.0130915	0.0022184
REVSALES	PRODUCTION	1.0000000	0.3897869	0.0286003	0.1022976	0.1139070	0.1102099	0.2389092	0.0011488	0.0129053	0.0022351
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.3897869	0.0286003	0.1022976	0.1139070	0.1102099	0.2389092	0.0011488	0.0129053	0.0022351
REVYEC	PRODUCTION	1.0000000	(0.2974495)	0.0177071	(0.0985646)	0.4820676	(0.3670414)	1.2482367	0.0000000	0.0167416	(0.0016974)
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	(0.2974495)	0.0177071	(0.0985646)	0.4820676	(0.3670414)	1.2482367	0.0000000	0.0167416	(0.0016974)
TDOMX	PRODUCTION	0.0000283	0.0000134	0.0000005	0.0000025	0.0000029	0.0000029	0.0000061	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0255208	0.0120649	0.0004903	0.0022583	0.0025873	0.0026252	0.0054733	0.0000215	0.0000000	0.0000000
	SUBTRAN	0.0113057	0.0051134	0.0002160	0.0009897	0.0011382	0.0012533	0.0025859	0.0000091	0.0000000	0.0000000
	DISTPRI	0.5540829	0.3654869	0.0151219	0.0680181	0.0713378	0.0334769	0.0000000	0.0006413	0.0000000	0.0000000
	DISTSEC	0.3460297	0.2522708	0.0129457	0.0349351	0.0418253	0.0001845	0.0000000	0.0003619	0.0029566	0.0005498
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0630325	0.0229487	0.0080628	0.0039931	0.0021598	0.0014422	0.0008984	0.0000073	0.0199923	0.0035280
	Total	1.0000000	0.6578981	0.0368373	0.1101968	0.1190512	0.0389850	0.0089637	0.0010412	0.0229489	0.0040778
TDPLANT	PRODUCTION	0.0015987	0.0007558	0.0000307	0.0001415	0.0001621	0.0001645	0.0003429	0.0000013	0.0000000	0.0000000
	BULKTRAN	0.3015773	0.1425706	0.0057943	0.0266857	0.0305735	0.0310216	0.0646776	0.0002540	0.0000000	0.0000000
	SUBTRAN	0.1328384	0.0600809	0.0025382	0.0116292	0.0133733	0.0147263	0.0303832	0.0001074	0.0000000	0.0000000
	DISTPRI	0.2826567	0.1864474	0.0077142	0.0346984	0.0363919	0.0170777	0.0000000	0.0003272	0.0000000	0.0000000
	DISTSEC	0.1953599	0.1424259	0.0073088	0.0197235	0.0236135	0.0001042	0.0000000	0.0002043	0.0016692	0.0003104
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0859689	0.0381541	0.0095380	0.0042341	0.0018182	0.0011472	0.0007150	0.0000086	0.0273392	0.0030146
	Total	1.0000000	0.5704347	0.0329242	0.0971123	0.1059325	0.0642415	0.0961187	0.0009028	0.0290084	0.0033250

KENTUCKY POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2009

TOTMXEXP	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6009083	0.3963741	0.0163998	0.0737663	0.0773666	0.0363060	0.0000000	0.0006955	0.0000000	0.0000000
	DISTSEC	0.3784580	0.2759124	0.0141589	0.0382090	0.0457450	0.0002018	0.0000000	0.0003958	0.0032337	0.0006013
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0206337	0.0008640	0.0003968	0.0002082	0.0001239	0.0000844	0.0000526	0.0000004	0.0171443	0.0017592
	Total	1.0000000	0.6731505	0.0309555	0.1121835	0.1232355	0.0365922	0.0000526	0.0010917	0.0203780	0.0023605
TOTOHLINES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6087940	0.4015757	0.0166150	0.0747343	0.0783818	0.0367825	0.0000000	0.0007046	0.0000000	0.0000000
	DISTSEC	0.3912060	0.2852062	0.0146359	0.0394961	0.0472858	0.0002086	0.0000000	0.0004091	0.0033426	0.0006216
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.6867820	0.0312509	0.1142304	0.1256677	0.0369911	0.0000000	0.0011138	0.0033426	0.0006216
TOTOX234	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	1.0000000	0.9896043	0.0503014	0.0236892	0.0037506	0.0004814	0.0000994	0.0000444	(0.0680033)	0.0000323
	Total	1.0000000	0.9896043	0.0503014	0.0236892	0.0037506	0.0004814	0.0000994	0.0000444	(0.0680033)	0.0000323
TOTOXEXP	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.4723812	0.3115945	0.0128921	0.0579886	0.0608188	0.0285406	0.0000000	0.0005467	0.0000000	0.0000000
	DISTSEC	0.2822139	0.2057463	0.0105582	0.0284923	0.0341118	0.0001505	0.0000000	0.0002951	0.0024114	0.0004484
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.2454049	0.1160457	0.0403969	0.0199595	0.0107502	0.0071719	0.0044677	0.0000366	0.0352672	0.0113090
	Total	1.0000000	0.6333864	0.0638472	0.1064403	0.1056808	0.0358630	0.0044677	0.0008785	0.0376786	0.0117574
TOTUGLINES	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	SUBTRAN	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTPRI	0.6250000	0.4122656	0.0170573	0.0767237	0.0804684	0.0377616	0.0000000	0.0007234	0.0000000	0.0000000
	DISTSEC	0.3750000	0.2733914	0.0140296	0.0378599	0.0453270	0.0002000	0.0000000	0.0003922	0.0032042	0.0005958
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.6856570	0.0310869	0.1145837	0.1257954	0.0379616	0.0000000	0.0011156	0.0032042	0.0005958
TRANS_TOTAL	PRODUCTION	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	BULKTRAN	0.6930000	0.3276155	0.0133147	0.0613216	0.0702554	0.0712851	0.1486239	0.0005836	0.0000000	0.0000000
	SUBTRAN	0.3070000	0.1388516	0.0058660	0.0268759	0.0309068	0.0340336	0.0702179	0.0002482	0.0000000	0.0000000
	DISTPRI	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	DISTSEC	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	ENERGY	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	CUSTOMER	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
	Total	1.0000000	0.4664672	0.0191807	0.0881975	0.1011622	0.1053188	0.2188418	0.0008318	0.0000000	0.0000000

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY — CASE NO. 2009-00459

DIRECT TESTIMONY
OF
DAVID E. JOLLEY

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
DAVID A. JOLLEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

DIRECT TESTIMONY OF
DAVID A. JOLLEY, 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 David A. Jolley. I am employed as a Senior Compensation Consultant for American Electric Power Service Corporation (AEPSC). My business address is American Electric Power, 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

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

A. I received a Bachelor of Science degree in Production and Operations Management from The Ohio State University in 1976, and have been certified as a Compensation Professional by World at Work, the world's leading professional association dedicated to knowledge leadership in the fields of compensation, benefits and total rewards. In 2000 I was awarded a lifetime achievement award by the American Compensation Association. From 1976 through 1987 I worked for Anchor Hocking Glass Corporation in Lancaster, Ohio in a variety of operations and human resources management positions. I began working in the compensation field in 1984. From 1987 to 1990 I worked for Bank One in Columbus, Ohio as a Senior Compensation/Organizational Design Consultant. I began working for the compensation section of AEPSC in 1990 as a Senior Compensation Consultant in the compensation section of AEPSC's system human resources department, a position I continue to hold. In my current position I am responsible for conducting research regarding the compensation market to maintain the effectiveness of AEP's compensation programs for employees of AEPSC, Kentucky Power Company (KPCO or Company) and other AEP affiliates.

This activity includes the development and review of position descriptions, the submission of AEP compensation data to a wide variety of compensation surveys and the subsequent review and analysis of compensation data from surveys in order to develop new or modify existing compensation programs for employees of AEP affiliates. I conduct ongoing research and recommend changes as necessary to maintain the competitiveness of AEP's compensation programs. In addition, I monitor compliance with federal and state regulations regarding compensation.

Q. WHAT SERVICES DOES THE AEPSC COMPENSATION SECTION PROVIDE TO KPCO?

A. The compensation section develops and maintains compensation programs for KPCO that are market competitive and aligned with AEP's various business strategies. The compensation section conducts ongoing research and recommends changes to compensation programs as necessary. The compensation section develops communications materials in support of compensation programs, and monitors compliance with federal and state regulations related to compensation.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I filed testimony with the Public Utility Commission of Texas (PUC or Commission) and testified on compensation issues in the last AEP Texas Central Company (TCC) and AEP Texas North Company (TNC) rate cases, Docket No. 33309 and 33310 and the previous TCC case, Docket No. 28840. I filed testimony with the Oklahoma Corporation Commission and testified on compensation issues in cause No. 200800144 and cause No. 200600285 for AEP Public Service Oklahoma Company and also filed testimony and testified before the Indiana Utility Regulatory Commission in cause No. 43306 for AEP Indiana Michigan Power Company.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to show that the compensation levels for employees of KPCO and AEPSC are necessary, reasonable and market competitive. I also support the reasonableness of the portion of AEPSC affiliate charges to KPCO that include base pay and incentives.

IV. REASONABLENESS OF AEP'S COMPENSATION LEVELS

A. OVERVIEW

Q. WHAT IS AEP'S APPROACH TO COMPENSATING EMPLOYEES?

A. It is the practice of AEP and its operating companies, as well as AEPSC, to provide total compensation that targets median wage levels for companies of similar size and scope within the electric utility industry for most positions. This practice allows AEP to attract, retain and motivate qualified employees at competitive wages, without being a wage leader within the electric utility industry. Employees are compensated through a combination of base pay and incentive pay programs. All employees are eligible for some level of annual incentive compensation, and approximately 500 management level positions throughout AEP are also eligible for long-term incentives. AEPSC and the AEP Operating Companies such as KPCO utilize a "pay for performance" program for all salaried positions whereby each employee's performance is evaluated on at least an annual basis against pre-determined performance objectives.

Q. WHY DO THE AEP COMPENSATION PROGRAMS INCLUDE AN INCENTIVE ELEMENT, AS OPPOSED TO INCLUDING ALL COMPENSATION AS BASE PAY?

A. AEP offers incentive compensation programs to employees to drive behavior and support the Company's strategic objectives and business goals. These programs permit employees to focus on measures that, when met, will benefit all stakeholders – customers, shareholders and employees. Incentive compensation programs support KPCO's mission of providing cost efficient, safe and reliable electric service through the attraction, retention and motivation of highly qualified employees. I explain in more detail below how the incentive program helps to accomplish this goal.

Q. PLEASE EXPLAIN HOW YOU DETERMINE THAT AEP'S COMPENSATION LEVELS ARE REASONABLE AND COMPETITIVE.

A. The AEPSC compensation section annually reviews compensation survey data to determine the competitiveness and cost effectiveness of its compensation programs. This is standard practice in both the utility industry and other industries across the country. Third-party compensation consulting companies such as Towers Perrin, Mercer, and Hewitt & Associates provide surveys used by the compensation staff in the review of compensation programs. The following surveys are regularly used in this process:

- Towers Perrin Energy Services Industry Middle Management and Professional Database
- Towers Perrin Energy Services Industry Executive Compensation Database
- Mercer Information Technology Survey
- Mercer Finance, Accounting & Legal Survey
- Mercer Logistics & Supply Chain Survey
- Mercer Metropolitan Benchmark Survey –South West US
- Mercer Annual Salary Planning Survey
- Hewitt & Associates Annual Salary Planning Survey
- World at Work Annual Salary Planning Survey
- Compensation Resources Annual Salary Planning Survey
- EAP Data Solutions Nonexempt Technical, Craft & Clerical Survey

Q. WHAT TYPE OF SPECIFIC INFORMATION IS INCLUDED IN THESE SURVEYS?

A. Compensation surveys typically include a description of the job, the number of companies that have a similar position, the number of incumbents in each position, the level of base and incentive compensation reported by each company and summaries of the compensation data by company type, company size and geographic location.

Q. WHY IS IT NECESSARY TO USE SUCH A VARIETY OF COMPENSATION SURVEYS?

A. Some surveys are function specific, covering areas such as legal, accounting, human resources, information technology, and provide information covering a broad range of positions within the functional area. Other surveys are industry specific, such as the energy services industry. Utilizing a large pool of information in establishing salary ranges and pay programs supports better decision making.

Q. HOW ARE THESE SURVEYS USED IN SETTING EMPLOYEE COMPENSATION?

A. AEP uses this survey information to establish salary ranges for each position at AEPSC, KPCO and the other AEP affiliates. The objective is to have the midpoint of the salary range for each position established at the median or 50th percentile of the comparable survey data. The company's process for the review of compensation levels and establishment of salary ranges is consistent with compensation practices at other companies, both within the electric utility industry and general U.S. industry as a whole.

Q. WHY IS THE MEDIAN SURVEY SALARY CHOSEN AS THE MIDPOINT FOR THE SALARY RANGE FOR AEP AFFILIATES?

A. Use of the median to establish compensation levels is an accepted industry standard, minimizes the potential for one company's data to influence that survey sample and helps to ensure that we are not an industry leader in pay, or lagging behind the market.

Q. HOW IS INCENTIVE PAY CONSIDERED IN UTILIZING THE SURVEY DATA AND ESTABLISHING COMPENSATION LEVELS?

A. The median level of incentive pay reported in compensation surveys is utilized to establish the "target" incentive opportunity assigned to similar positions at AEP and its affiliates. The target incentive level is expressed as a percentage of base compensation.

Q. DOES THE USE OF THE SURVEY MEDIAN AS A TARGET MEAN THAT EMPLOYEE SALARIES WILL INVARIABLY FALL AT THE MEDIAN?

A. No. The median is used to establish the midpoint of the salary range assigned to each position. The salary range extends approximately 22.5% above and below the midpoint, a common compensation design practice. Individual salaries may fall anywhere within the assigned range depending on such factors as performance, qualifications and time in job.

B. BASE COMPENSATION

Q. PLEASE EXPLAIN HOW AEP MANAGES BASE COMPENSATION.

A. The base salary level for new employees of KPCO and the other AEP affiliates is determined by the qualifications and experience of the new employee relative to the minimum requirements the position requires. For positions with multiple incumbents, the base salaries of existing employees are also taken into consideration.

For existing employees, AEP and its affiliates utilize a "pay for performance" program for all salaried positions whereby each employee's performance is evaluated on at least an annual basis against pre-determined performance objectives, which include such things as quality and quantity of work, special projects, personal development and in the case of managers and supervisors, development of subordinate staff. The amount of each employee's base salary increase, also known as a "merit" increase is based on a combination of their individual performance, their performance relative to their peers, the level of the salary within their current salary range and the size of the merit increase budget. The amount budgeted annually for merit increases is influenced by information reported in salary planning surveys conducted annually by several large compensation consulting firms such as Mercer and World at Work as well as salary budget dollars available.

For the year 2008, the total merit increase budget for both exempt[1] and nonexempt salaried employees at KPCO, AEPSC and the other AEP Operating Companies was 3.7%. The Mercer 2008/2009 salary planning survey reported average merit increases granted by all companies at 3.8% for exempt salaried employees and 3.7% for nonexempt salaried employees. The 2008/2009 World at Work salary planning survey reported that average merit increases granted by all companies for exempt salaried employees were 3.6% and 3.6% for nonexempt salaried employees.

For the year 2009, the total merit increase budget for both exempt and nonexempt salaried employees at KPCO, AEPSC and the other AEP Operating Companies was 0%. The Mercer 2009/2010 salary planning survey reported average merit increases granted by all companies at 2.2% for exempt salaried employees and 2.2% for nonexempt salaried employees.

[1] An "exempt" employee is one who is exempt from the overtime provisions of the Fair Labor Standards Act. A "non-exempt" employee is covered by the Fair labor Standards Act and is eligible for overtime compensation for all hours worked over 40 in a work week.

The 2009/2010 World at Work salary planning survey reported that average merit increases granted by all companies for exempt salaried employees were 2.0% and 1.9% for nonexempt salaried employees.

The amount of merit increase granted to any individual employee is a function of their individual performance and the position of their base salary within their assigned salary range. In total, the merit increases for all employees cannot exceed the overall approved merit increase budget. In addition to merit increases, some employees may also receive promotional increases to recognize the assumption of greater responsibilities. As a result, in any given year, total pay increases will slightly exceed the merit increase budget.

Q. WHAT LEVEL OF MERIT INCREASE IS PLANNED FOR 2010?

A. Final merit increase budgets will not be approved until late 2009, but at this time, it is expected that the merit increase budget will be 2.0% for all nonexempt employees and exempt employees below the Officer level. This merit budget percent was utilized by witness Wohnhas in the Company's wage and salary adjustment. As noted above, some employees may also receive promotional increases to recognize the assumption of greater responsibilities. As a result, in any given year, total pay increases will slightly exceed the merit increase budget.

Q. HOW ARE BASE PAY INCREASES HANDLED FOR HOURLY/CRAFT EMPLOYEES OF AEP AND KPCO?

A. Base pay increases for hourly/craft employees—that is, employees who typically perform work such as line mechanics and meter readers are known as "general increases" and apply across the board to all such employees. The general increase percentage increase is determined on an annual basis by reviewing survey data projections provided by other employers of these types of positions. Hourly/craft employees at KPCO and the other AEP operating companies were granted a 3.1% general increase in 2008. No general increase was granted in 2009 however; hourly employees may also receive promotional increases to recognize the assumption of greater responsibilities, and may also receive step-rate increases at 6 month intervals as prescribed by union contracts. As a result, overall increases for hourly employees will slightly exceed the general increase in any given year.

Q. WHAT DO YOU CONCLUDE ABOUT AEP'S AND KPCO'S BASE COMPENSATION FROM THE ABOVE DESCRIBED DATA?

A. The processes by which AEP and KPCO manage their base compensation through merit increases for salaried employees and general increases for hourly/craft employees, promotional increases and step-rate progressions are consistent with the practices of other employers in both the energy services industry and industry as a whole. The amounts budgeted for merit and general increases have been consistent with to slightly below the market.

C. INCENTIVE COMPENSATION

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

A. Incentive compensation plans are formal plans, fully described in written documents and approved by the Company's senior management. These plans cover all employees from hourly positions through managers. The plans applicable to KPCO include the Utilities Group Plan, the Generation Plan, the Shared Services Plan and the Environmental, Safety, Health and Facilities Plan. The plans applicable to AEPSC include the Utilities Group Plan, Generation Plan, the Shared Services Plan, the Finance Plan, the Corporate Communications Plan, the Environmental, Safety, Health and Facilities Plan and the Corporate Plan.

Q. HOW IS AN EMPLOYEE'S INCENTIVE COMPENSATION AMOUNT DETERMINED?

A. Each performance measure in the incentive plan has a minimum, target, and maximum performance level that correspond to a performance factor or score of 0 for minimum performance, 1.0 for achievement of target performance and 2.0 for achievement of maximum performance. At the conclusion of the year, the resulting performance scores for each measure are multiplied by their corresponding weight, and summed to arrive at an overall performance score ranging from 0 to 2.0. This score may then be adjusted up or down through what is known as the operating unit performance adjustment. The score is then multiplied by the Earnings Per Share (EPS) modifier, also a value of between 0-2.0 to arrive at the final, overall performance score, a value from 0 to a maximum of 2.0.

The monetary award paid to an employee is a function of their final overall performance score times their incentive target times their earnings for the period covered by the incentive plan (the previous calendar year). In addition, all exempt employee awards may be adjusted upward or downward based on individual performance. The target payout percentages vary by employee salary grade level and vary from 5% of earnings for non-exempt employees to 5-15% of earnings for exempt employees, and 25-30% of earnings for exempt management employees. Senior management employees have incentive targets of between 30-100% of earnings, depending on their assigned salary grade. A participant's maximum individual award percent is the greater of two times his or her target award percent, or the Overall Score plus 50%.

Q. ARE THE MEASURES CONTAINED WITHIN THE VARIOUS ANNUAL PLANS CONSISTENT WITH RATEPAYER INTERESTS?

A. Yes, they are. The various operational measures (*i.e.*, reliability, commission complaints, customer satisfaction, process improvement, and safety) benefit customers by promoting reliable, efficient and safe operations.

The various financial measures (*i.e.*, O&M budget and capital budget) benefit customers by promoting the optimal use of the Company's limited financial resources, leading to O&M and capital cost control, encouraging the pursuit of all sources of additional earnings, and contributing to the financial health of the Company, all of which benefits both customers and shareholders alike. Customers' interests are furthered when KPCO provides service as effectively and efficiently as possible, and this is often best measured from a financial perspective.

Q. ARE THESE INCENTIVE PROGRAMS NECESSARY TO ATTRACT AND RETAIN QUALIFIED EMPLOYEES?

A. Yes. As I explained above, these programs are necessary for KPCO, AEPSC and the other AEP operating companies to be able to compete with other employers for the qualified employees necessary to provide quality utility service, as well as to incent that employee to achieve goals which positively affect customer satisfaction, safety and financial performance. Moreover, each of the performance measures I described above promotes either cost control and fiscal responsibility (Capital expenditure, O&M measures), service reliability and customer satisfaction (SAIFI, customer satisfaction and commission complaint measures), or operational safety (safety measures). In each instance, these measures are consistent with the provision of quality utility service at reasonable cost.

Q. HOW DO THE INCENTIVE COMPENSATION PLAN TARGETS COMPARE TO OTHER COMPANIES IN TERMS OF THE PERCENTAGE OF COMPENSATION PAID UNDER THE INCENTIVE PLAN?

A. EXHIBIT DAJ-1 compares AEP's incentive plan targets for KPCO, AEPSC and the other AEP Operating Companies, by employee level, to data reported in the 2008 Mercer and World at Work Salary Planning surveys. This exhibit shows data on a national level and for other utilities. The exhibit indicates that AEP's incentive plan targets are consistent with those reported in these surveys for nonexempt positions and slightly below the targets reported for exempt and officer/executive positions.

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT THESE INCENTIVE PLANS ARE PART OF A TOTAL COMPENSATION PACKAGE.

A. AEP'S incentive compensation plans are not designed as "bonuses" or additions to an already appropriate level of compensation. Instead, the Company designs an overall compensation package that includes an incentive compensation portion to reward employees for the achievement of strategic objectives that are both financial and operational in nature. It is the entirety of this compensation package that allows the Company to provide a competitive salary, and therefore attract and retain qualified, highly motivated employees able to support reliable, cost effective service to customers.

Q. IS THE COMPANY REQUESTING THAT ONLY INCENTIVE COMPENSATION PAID DURING THE TEST YEAR BE INCLUDED IN ITS REVENUE REQUIREMENT IN THIS CASE?

A. No, it is not. It is requesting that the target amount of incentive compensation during the test year ($5,650,647) be included in cost of service, rather than the ($4,400,529) in actual incentive compensation in the test year. Incentive compensation during the test year was less than target amounts. The Company is requesting that target amounts be included in cost of service because this is the amount that is designed to ensure that employee salaries will be competitive and it is consistent with normalized levels. Witness Wohnhas supports this pro forma adjustment, which is shown on Exhibit RKW-1.

Q. ARE INCENTIVE COMPENSATION PLANS COMMON IN THE ELECTRIC INDUSTRY?

A. Yes, they are. Incentive compensation plans similar to the plans that AEP employs are widespread in the utility industry and industry as a whole. The 2008 Towers Perrin Energy Services Industry Middle Management and Professional Survey reported that 104 of 109 companies participating in the survey have annual incentive plans similar to AEP'S. The following highlights from two major compensation surveys that are commonly used by industry professionals to compare and design compensation programs support the use of incentive pay in today's business environment.

The 2008 Mercer US Compensation Planning Survey reported that 87% of the 1,000 responding companies and 89% of utilities offer incentive pay programs to all employees. The Mercer survey also reported that key performance measures are, in order of prevalence, financial, operational and customer satisfaction related in nature, similar to the design of AEP's programs. The 2008 World at Work Salary Budget Survey reported that the number of companies using incentive pay programs continues to increase each year and that 81% of 2,729 responding companies were using incentive pay programs in 2008. As such, these plans are necessary to attract and retain qualified employees. KPCO'S and AEPSC's ability to attract and retain qualified employees, moreover, has a very real and direct effect on the quality of customer service.

Q. **WHAT WOULD BE THE IMPACT IF KPCO'S AND AEPSC'S EMPLOYEE COMPENSATION LEVELS WERE SET FOR RATEMAKING PURPOSES**

WITHOUT INCLUSION OF AMOUNTS FOR THESE INCENTIVE PROGRAMS?

A. If this were to occur, KPCO's rates would not support payment of total compensation competitive with the total compensation being paid in the market by the employers with whom KPCO and AEPSC competes to obtain qualified employees. In essence, absent recognition of incentive pay for rate setting purposes, KPCO's rates would only support salaries that would fall below what constitutes a competitive, market based total compensation package.

D. SENIOR MANAGEMENT COMPENSATION

Q. PLEASE EXPLAIN AEP'S MANAGEMENT COMPENSATION PROGRAM.

A. AEP uses a market-based pay philosophy for managers that are similar to that used for other positions. In addition to base pay and annual incentives, the compensation program for senior managers also includes long-term incentives. Approximately 500 senior managers participate in this program. The combination of base salary, annual and long-term incentives balances both the long and short term interests of customers, shareholders and employees alike. The Human Resources Committee of the AEP Board of Directors annually reviews AEP's senior management compensation program in the context of performance of management and performance of AEP. In carrying out its responsibilities, the Human Resources Committee has hired a nationally recognized independent consultant (Towers Perrin) to provide recommendations to the Human Resources Committee regarding AEP's senior manager compensation and benefits programs and practices, and to provide information on current trends in senior manager compensation and benefits within the energy services industry and among U.S. industrial companies in general. The Human Resources Committee regularly holds meetings with its independent consultant without management present to help insure that it receives full and independent advice. In setting compensation levels, The Human Resources Committee recognizes that AEP's senior management team is charged with managing one of the largest and most geographically diverse electric generation, transmission and distribution companies in a dynamic business atmosphere that requires high levels of business and management innovation and expertise.

The Human Resources Committee annually reviews AEP's senior management compensation relative to a peer group comprised of companies that represent the talent markets from which AEP must attract and retain managers. For 2008, the compensation peer group consists of 14 large and diversified energy services companies, plus 12 Fortune 500 companies, which, taken as a whole, approximately reflect the company's size, scale, business complexity and diversity. The Human Resources Committee generally uses median compensation information of the compensation peer group as its benchmark but does consider other comparisons, such as alternative percentile benchmarks and industry-specific compensation surveys, when evaluating compensation.

Q. PLEASE EXPLAIN AEP'S LONG-TERM INCENTIVE PROGRAM.

A. The primary purpose of AEP's long-term incentive program is to motivate managers to maximize shareholder value by linking a portion of their compensation directly to shareholder return and to take a longer, more strategic view of the business. The current long-term incentive program provides grants or awards in the form of performance units (units are similar to shares of AEP common stock but have no voting rights) with a three-year performance and vesting period beginning January 1st of each year. Performance units may become earned subject to two equally weighted performance measures: three-year total shareholder return measured relative to the S&P Utilities and three-year cumulative earnings per share measured relative to a Board approved target. The scores for these performance measures determine the percentage of the performance units outstanding at the end of the performance period that are earned and can range from zero to 200%. The value of each performance unit that is earned equals the 20-day average closing price of AEP Common stock for the last 20 days of the performance period.

Q. **WHAT IS THE AMOUNT OF THE LONG TERM INCENTIVE PROGRAM THAT THE COMPANY IS REQUESTING BE INCLUDED IN COST OF SERVICE IN THIS CASE?**

A. KPCO is requesting $990,858 be included in cost of service. Witness Wohnhas supports this amount as shown on Exhibit RKW-1.

Q. **IS THE LONG TERM INCENTIVE PROGRAM REASONABLE AND NECESSARY TO SUPPORT RELIABLE UTILITY SERVICE?**

A. Yes, companies of AEP's size and complexity offer similar programs, so that AEP cannot hope to attract the highly qualified professionals needed to manage its utility service unless it offers such a program. Towers Perrin, a leading compensation consulting firm, reports that 99 of 102 companies that participated in its 2008 Energy Services Executive Compensation Survey have long term incentive programs for their managers. Moreover, the focus of AEP's overall operations is the success of KPCO and the other AEP operating companies. Management ensures that shareholder value is increased, among other things, by working to improve the efficiency and reliability of the utility services provided by KPCO and the other AEP Operating Companies, while at the same time adopting measures to maintain their operating costs at reasonable levels.

Q. HOW DO CUSTOMERS BENEFIT FROM HIGHER EARNINGS AND GREATER SHAREHOLDER RETURNS?

A. The managers participating in the long term incentive program have a responsibility to fulfill earnings goals through successful management of overall company operations. When operations are conducted consistently at or under budget, this supports not only the earnings objectives of shareholders, but also the reasonable O&M and capital cost levels that are an objective of PUCT rate setting. Higher earnings translate into stronger financial integrity and stability and access to the capital markets on lower cost terms. Having compensation tied to performance factors such as increased shareholder return is also in the best interest of both customers and shareholders. Utility ratepayers benefit from efficient and effective operations, strong leadership and satisfactory results for shareholders. The Company cannot exist without shareholders. If shareholders are satisfied with the financial performance of the Company and are willing to provide additional investments, ratepayers also benefit. Accordingly, there is no inconsistency between the performance measures in the long term incentive plan and the interests of utility customers.

V. CONCLUSION

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY.

A. AEP'S compensation levels and program design are necessary, reasonable, and market competitive and ensure that AEP and KPCO are able to attract, retain, and motivate the workforce required to provide reliable, cost effective electric service to its customers.

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

A. Yes.

AFFIDAVIT

David A. Jolley, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

David A. Jolley
David A. Jolley

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by David A. Jolley this 17th day of December 2009.

Curt D Cooper
Notary Public

My Commission Expires No expiration

NOTARIAL SEAL STATE OF OHIO
CURT D. COOPER, ATTORNEY AT LAW
Notary Public, State of Ohio
My Commission has no expiration

EXHIBIT DAJ-1

2008 Incentive Compensation Target Levels

Employee Group	**AEP Target %** (1)	World at Work Survey Utilities	National	Mercer Survey National	Utilities
Salaried Nonexempt	5.0%	5.9%	5.7%	5.0%	6.0%
Exempt	9.6%	10.7%	12.2%	10.0%	10.0%
Officers/Executives	26.6%	37.0%	34.1%	40.0%	50.0%

(1) Weighted average of targets for all employees by level

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2009-00459

DIRECT TESTIMONY
OF
THOMAS M. MYERS

ON BEHALF OF
KENTUCKY POWER COMPANY

December 29, 2009

DIRECT TESTIMONY OF
THOMAS M. MYERS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2009-00459

TABLE OF CONTENTS

**DIRECT TESTIMONY OF
THOMAS M. MYERS, 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 Thomas M. Myers. My position is Vice President – Commercial & Financial Analysis for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power, Inc (AEP). AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including Kentucky Power Company ("Kentucky Power, KPCo or Company"). My business address is 155 West Nationwide Boulevard, Columbus, Ohio 43215.

II. Background

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I received a Bachelor of Science degree in finance from the University of Colorado. I also received a Masters of Business Administration from California State University, East Bay. I joined AEP in 2002, holding a number of management positions where I was the assistant accounting controller supporting Commercial Operations and Fuel, Emissions & Logistics. As the assisting accounting controller, I was responsible for fuel accounting and reporting, energy accounting, and the associated financial reporting. I was also the managing director – Regulatory Accounting Services. As managing director, I managed employees who participated as accounting witnesses in regulatory proceedings. I also ensured that rate orders across the AEP System were properly accounted for and reported in the financial statements. Prior to joining AEP, I was employed at Enron Corporation and at Chevron, working mostly in energy accounting and reporting roles. I was promoted to my present position in January 2008.

Q: WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT – COMMERCIAL & FINANCIAL ANALYSIS?

A: As Vice President – Commercial & Financial Analysis, I am responsible for the mid- and back-office functions in Commercial Operations, which include structuring, portfolio and margin analysis, regional transmission organization (RTO) and commodity settlements, contract administration and generation forecasting. Commercial Operations offers AEP's generating units into the PJM Interconnection, L.L.C. RTO (PJM[1]), dispatches its generating fleet in coordination with PJM and engages in market operations, first in order to produce energy that is necessary to serve AEP native load customers, and then in support of off-system sales (OSS) margins. In addition, Commercial Operations engages in trading of energy commodities.

III. Purpose of Testimony

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

A: The purpose of my testimony is to support the Company's proposed modification to the system sales clause for OSS margins and to describe AEPSC's role in managing and optimizing OSS margins. More specifically, my testimony will describe the following:

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[1] PJM Interconnection, LLC is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. AEP is both a transmission provider and a market participant in the PJM energy market. PJM charges and credits associated with serving AEP's native load and off-system sales (OSS) are invoiced ("financially settled" or "settled") to AEP by PJM.

- The proposed modification to the current sharing mechanism in the system sales clause.
- The reasons a modified system sales clause sharing mechanism for OSS margins makes sense, and why it provides a balance of risk and reward, along with appropriate incentives to both the customers and shareholders.
- A description of OSS margins and the manner in which they are produced.
- The attendant complexities of risks and rewards that AEPSC incurs in the wholesale power market and how, by actively managing those risks, AEPSC creates significantly more OSS value for its customers than would be created if it did not manage these risks.
- The impact of transformations in the wholesale power markets.
- Various trading instruments that AEPSC uses and the different markets in which AEPSC is involved.
- The benefits that customers receive as a result of wholesale commercial activities.

My testimony will demonstrate that price volatility in the wholesale power markets and the associated risks warrant a modification to the manner in which OSS margins are shared between KPCo's customers and the Company. My testimony will also show how this modification results in a benefit for both the customers and the Company.

Q: ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A: Yes, I am sponsoring the following exhibits, which were prepared under my direction and supervision:

- Exhibit TMM-1: Types of Risk Managed by AEPSC, page 1 of 1.

- Exhibit TMM-2: Type of Fuel Used by Marginal PJM Unit January 1999-June 2009, page 1 of 1.
- Exhibit TMM-3: Historical Price of NYMEX Gas Contracts and Volatility January 1990-October 2009, page 1 of 1.
- Exhibit TMM-4: TDB-4 Historical Price of NYMEX Coal Contracts and Volatility January 2001-October 2009, page 1 of 1.

IV. Current OSS Sharing Mechanism and Proposed Modification

Q: WOULD YOU PLEASE DESCRIBE THE COMPANY'S CURRENT SYSTEM SALES CLAUSE RELATED TO THE TREATMENT OF OSS MARGINS?

A: Per the settlement agreement in the Company's last base rate case, Case No. 2005-00341, the System Sales Clause tariff for OSS margins is to be calculated using an annual baseline of $24,855,326. OSS margins that exceed the baseline amount of $24,855,326, but that are less than $30,000,000, are shared between KPCo customers and the Company on a 70%-30% basis, respectively. If the Company's annual OSS margins exceed $30,000,000, then the monthly sales margins amount in excess of $30,000,000 is shared between KPCo customers and the Company on a 60%-40% basis, respectively.

Q: WOULD YOU PLEASE DESCRIBE THE COMPANY'S PROPOSED MODIFICATION TO THE CURRENT SYSTEM SALES CLAUSE RELATED TO THE TREATMENT OF OSS MARGINS?

A: The Company is proposing to credit, in base rates, the KPCo retail jurisdictional customers (KPCo customers) with $7,645,182. This is equal to 50% of the test year level of OSS margins of $15,290,363. KPCo customers will receive this credit even if future OSS margins are less than $7,645,182. Thereafter, the Company will retain OSS margins until the total for the annual period equals the test year period amount. Once the OSS margins for the annual period reach the test year level of $15,290,363 any additional margins will be shared on a 50%-50% basis between the KPCo retail jurisdictional customers and the Company. Greater detail concerning test year margins and an explanation as to how the modified OSS margins sharing mechanism will work are provided in the testimony of Company Witness David M. Roush.

V. OSS Margin Sharing: Rationale for Modification

Q: HOW IS THE PROPOSED MODIFICATION TO THE SYSTEM SALES CLAUSE APPROPRIATE FOR KPCO CUSTOMERS?

A: The proposed modification provides a level of certainty for customers in the form of an embedded base rate credit of $7,645,182. In addition, customers will not be required to contribute (in the form of system sales clause charges) in the event the annual OSS margins are less than those built into rates. Under the current system sales clause, there is no assurance customers will receive the benefit of the test year level of OSS margins. In fact, when the Company is unable to achieve this OSS margin sharing objective, KPCo customers must absorb, in some cases, up to 70% of the difference between the actual monthly level of margins and the amount of that month's base rate credit. For example, KPCo customers absorbed a percentage of the base rate OSS margin credit shortfall during the test year. Expecting KPCo customers to account for up to 70% of the difference when the Company is unable to achieve the baseline level of credit creates a situation in which the customers are responsible for a portion of the shortfall in OSS margin production. The proposed modification to the OSS margin sharing mechanism removes most of the uncertainty associated with a base rate credit that is closely tied to volatility in the wholesale power market. KPCo customers will not be credited with less than $7,645,182, which is one half of the test year level of OSS margins of $15,290,363. Essentially, the proposed modification eliminates any OSS shortfall effect on KPCo customers by including a reasonable embedded level of OSS margins in base rates. Stated otherwise, the customers will receive OSS margins equal to 50% of the test year amount, and once the test year level of OSS margins is exceeded the customers will share in 50% of any additional OSS margins during the annual period. The proposed modification is appropriate for KPCo customers in that it provides them with stability, especially during times of economic uncertainty.

Q: HOW IS THE PROPOSED MODIFICATION TO THE SYSTEM SALES CLAUSE APPROPRIATE FOR THE COMPANY?

A: By allowing KPCo to effectively retain 50% of OSS margins if the Company meets or exceeds the test year level of margins, the Company receives a reasonable benefit for incurring 100% of the risk associated with embedding in retail rates for KPCo customers 50% of the test year level of OSS margins. It is important to have a system sales clause that does not expose KPCo to unreasonable financial risks. This proposed modification does result in risk for KPCo, but does not create the potential for extreme negative financial outcomes which could adversely impact KPCo's ability to serve customers. The proposed modification to the system sales clause provides a prudent incentive for AEPSC to optimize OSS margins by incurring and effectively managing the risks and volatility inherent to the wholesale power markets.

Q: DOES THE PROPOSED MODIFICATION TO THE SYSTEM SALES CLAUSE LIMIT THE LEVEL OF OSS MARGINS THAT CAN BE CREDITED TO KPCO CUSTOMERS?

A: No. In any year when the level of the KPCo retail jurisdictional share of OSS margins exceeds $15,290,363, every dollar thereafter will be shared equally between KPCo customers and the Company. Equal sharing of the OSS margins above the test year level provides AEPSC with an incentive mechanism to optimize the margins in such a manner that will benefit KPCo customers and provide a reasonable reward to the Company as well.

Q: ARE THERE OTHER REASONS WHY THE COMPANY'S PROPOSED MODIFICATION TO THE SYSTEMS SALES CLAUSE RELATED TO THE TREATMENT OF OSS MARGINS IS APPROPRIATE?

A: The existing wholesale power markets have introduced additional risks into many parts of the utility business and these risks exist whether they are actively managed or not. Some of these risks were present at the time of the last rate case such as operating in PJM, while others have arisen more recently. One of the greatest risks arising over the last year has been managing the current downturn in the economy, which has resulted in the thinning of creditworthy counterparties in the market. AEPSC as agent on behalf of KPCo has taken the initiative to manage and optimize the value of the Company's generating assets while simultaneously confronting the significant amount at risk that exists in today's wholesale power markets.

The proposed modification to the current sharing mechanism helps to mitigate the significant and volatile costs associated with managing the aforementioned risks. OSS can potentially be a large component of revenue. But as the recent economic downturn has shown, there are still many factors that are beyond the control of the utility even though AEPSC actively manages the risk associated with the wholesale power market. The existing OSS margin sharing mechanism does not fully shield KPCo's customers and the Company against the volatility of OSS margins, nor does it provide the best balance of risk versus reward.

Q: WOULD YOU PLEASE EXPLAIN THE IMPACTS OF THE CURRENT FINANCIAL CRISIS IN TERMS OF REDUCED LOAD?

A: Yes. On average, PJM real-time peak load decreased in the first nine months of 2009 by

4.5 percent from the first nine months of 2008, falling from 80,611 MW to 76,956 MW.

PJM has forecasted an economic rebound in 2010. However, even given that assumption, PJM's 2009 Load Forecast estimates that peak load will not recover to 2008 levels until 2011.

Q: HOW HAS THE FINANCIAL CRISIS IMPACTED THE PRICE OF ENERGY IN THE PJM MARKET?

A: Beginning in the second half of 2008, market prices for electricity began to experience significant drops. This trend has continued into 2009. According to the 2009 third quarter, PJM State of the Market Report, PJM Real-Time Energy Market prices decreased in the first nine months of 2009 compared to the first nine months of 2008. Table 1, shown below, compares the Real-Time and Day-Ahead system simple average and load-weighted Locational Marginal Prices (LMP) over the first nine months of 2008 and 2009:

Table 1 – Locational Market Price Comparison: 2008 vs. 2009

	2008	2009	% Increase/(Decrease)
Real-Time: System Simple Average LMP	$71.94/MWh	$37.42/MWh	(48.0%)
Real Time: Load-Weighted LMP	$77.27/MWh	$39.57/MWh	(48.8%)
Day-Ahead: System Simple Average LMP	$71.43/MWh	$37.35/MWh	(47.7%)
Day-Ahead: Load-Weighted LMP	$75.96/MWh	$39.35/MWh	(48.2%)

The Locational Marginal Price in PJM is determined by the highest-cost, reliability-constrained, economical unit on-line, known as the marginal unit. This essentially determines the market price of the "next MW dispatched" based on the next reliability constrained, economic generating unit. In high demand periods prior to the downturn of the economy, the marginal unit was typically a natural gas fired combustion turbine, which is a peaking unit. Due to reduced demand, capacity and energy requirements in the PJM market, which typically are served during most hours by baseload coal units, it has become unnecessary in many instances for PJM to award higher-priced coal or gas peaking units. However, as demand has decreased, it is not unusual for a coal fired generator to be the marginal unit setting the energy component of the LMP. This has dramatically lowered market prices in comparison to those the market demonstrated at the same time last year.

The factors resulting in lower energy market prices are interrelated, but the net effect has been that more AEP sub-critical, less efficient coal units are not receiving a PJM market award (day-ahead and/or real-time) and are being kept off-line (Down Not Required). The demand for energy, and the amount and price of energy available to be purchased from the marketplace (i.e. the PJM RTO) impacts the economic dispatch of the AEP generating fleet by backing down (or keeping off-line) units that are not economic. This is the basis for the PJM market awards and an overall benefit to customers in that it lowers the overall fuel cost.

Q: GIVEN THE AFOREMENTIONED CHALLENGES, CAN YOU EXPLAIN THE REASONS WHY MODIFYING THE SHARING OF THE OSS MARGINS MORE APPROPRIATELY BALANCES RISKS AND REWARDS?

A: Yes. To operate in the current wholesale energy market, AEPSC must manage a significant amount of risk. AEPSC engages in energy trading and hedges or sells into the PJM Day-Ahead and Real-Time markets the output of its economic generation in order to optimize OSS margins and manage the associated risks. KPCo benefits from AEPSC's trading and marketing organization, which has invested in systems and personnel to manage these risks while continuing to optimize OSS margins. However, for AEPSC to continue to assume the incremental risk necessary to optimize OSS margins, it must be able to continue to participate in the margins created by this activity in a way that makes sense for both customers and the Company.

Q: WOULD YOU PLEASE SUMMARIZE THE COMPANY'S RATIONALE FOR PROPOSING A MODIFICATION TO THE CURRENT SYSTEM SALES CLAUSE?

A: The unprecedented economic downturn that has occurred in the past year has contributed to an OSS margin shortfall. The proposed modification to the OSS sharing mechanisms will better balance the risks and rewards associated with wholesale power markets. In addition, the Company is providing its customers with an assurance they do not have under the current system sales clause. Again, it is important to have a system sales clause that does not expose KPCo to extreme negative financial outcomes which could adversely impact KPCo's ability to serve customers.

VI. Description of OSS Margins

Q: IN YOUR TESTIMONY TO THIS POINT YOU HAVE MENTIONED OSS MARGINS. WOULD YOU PLEASE PROVIDE THE COMMISSION WITH AN EXPLANATION OF OSS MARGINS?

A: Yes. OSS margins are the net profit that results after taking the total revenue from all sales made to non-affiliated counterparties, and subtracting out the variable costs of making those sales. For example, sales to non-affiliated counterparties may include the sale of electricity from AEP generating units, the re-sale of purchased power, or margins from financial products such as swaps[2]. Variable costs include the cost of fuel, variable operating and maintenance (O&M), purchased power or costs associated with entering into a financial product.

Q: ARE OSS MARGINS CREATED SIMPLY FROM SELLING SURPLUS ENERGY INTO THE WHOLESALE POWER MARKET?

A: No, the current reality is much more complicated. As I will describe further in my

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[2] A swap, also known as a "contract for differences" or as a "fixed-for-floating" contract, is a financial trading instrument in which the two counterparties exchange one stream of cash flow for another stream. Swaps can be used for hedging purposes or for trading.

testimony, sales of surplus energy are just one of the ways that OSS margins are produced. Even that activity, selling surplus energy, requires a complex skill set and is much more complicated in today's volatile wholesale power markets. As I will further explain, the growth of RTOs, and of non-traditional and non-utility participants (that do not seek physical electricity for either their own, or their customer's needs), have resulted in an array of market impacts. Although the risks associated with the wholesale market cannot be entirely avoided, they can be prudently managed.

Q: PLEASE DESCRIBE PHYSICAL OSS MARGINS?

A: Physical OSS margins are best defined as the difference between AEP's cost of electricity sold and the revenue received for electricity that physically flows. The cost of electricity sold can be either the cost of AEP's generation (these costs would include the variable costs of operating, plus any PJM charges and credits), or purchased power costs. The revenues are derived from wholesale energy sales, hedging activities associated with AEP's generation, and trading and marketing efforts that settle physically. As I will further explain in my testimony, sales of surplus energy from the AEP generation fleet are just one of the ways that OSS margins are generated.

Q: DO ALL OSS TRANSACTIONS RESULT IN THE PHYSICAL FLOW OF ELECTRICITY?

A: No. Many of the megawatt-hours (MWh) involved in AEPSC's OSS trading transactions are never physically delivered, but are simply trades, either buying or selling, in the wholesale electric energy market. These may include physical transactions that are "booked out", as well as purely financial transactions that do not contemplate physical flow. A "booked out" transaction occurs when AEPSC has a purchase and sale of the same quantity for the same specific delivery period at the same specific delivery point. The offsetting sale and purchase transactions are financially settled rather than physically delivered resulting in "booked out" transactions. These transactions underscore the fact that it is extremely difficult to separate the impact of physical transactions versus financial transactions.

Q: HOW DOES AEPSC CREATE OSS MARGINS IN WHOLESALE POWER MARKETS?

A: AEPSC utilizes trading instruments such as swaps and options, actively following the developments in other commodity markets and factors that influence the price of electricity. Commercial Operations also participates in competitive energy auctions outside of AEP's service territory in PJM and in the Midwest Independent Transmission System Operator, Inc. (MISO), for example. This provides an additional revenue stream and additional margins that KPCo would forego without the Commercial Operations' capabilities of AEPSC. The following list identifies the broad set of activities that contribute to OSS margins, and shows how AEPSC's role has expanded beyond merely selling surplus energy to a broader scope of employing various methods to create OSS margins:

- Auction Participation
- Basis Trading
- Time-Spread Trading
- Spark Spreads
- Physical Sales of Surplus Energy and associated Hedging

As the list demonstrates, physical sales of surplus energy only accounts for one of the activities that optimizes OSS margins. I will further discuss the various methods used to create OSS margins at a later point in my direct testimony.

VII. Risk in Wholesale Power Markets and Impacts

Q: WHAT ARE SOME OF THE RISKS THAT AEPSC MUST FACE IN CURRENT WHOLESALE POWER MARKETS?

A: Not only is there the extreme volatility of electricity prices, but with the multitude of new non-creditworthy market participants, the growth of ISOs/RTOs, the development of various trading hubs, the introduction and rising importance of financial trading instruments, and the changing market rules, there is an array of forces that tend to increase the level of risk associated with the wholesale power markets. Exhibit TMM-1 identifies the different types of risk encountered and appropriately managed by AEPSC. I will explain how, by actively managing these risks, AEPSC creates significantly more OSS value. Having the appropriate risk measures in place limits the downside risk exposure to the customer and the company.

Q: CAN YOU PROVIDE EXAMPLES OF THE VOLATILITY THAT OCCURS IN TODAY'S COMPETITIVE WHOLESALE MARKET?

A: Price volatility is but one example of a market risk that AEPSC manages. Volatility, referring to unpredictable price changes over time, and typically measured using the standard deviation, is a reflection of the degree of risk faced by a company with exposure to that component.

Most new generating capacity brought online in the early 2000's that began to have a greater influence on the price of electricity in the Midwest was natural gas-fired. Increasingly, natural gas-fired generation was "on the margin"; that is, the marginal cost of supplying the next increment of power was determined by a natural gas-fired generating unit. Exhibit TMM-2 illustrates that the percentage of gas units setting the marginal price in PJM has grown since 2000, peaked in 2004, and has remained high. The sustained high level of gas-fired generation however, has caused the wholesale price of electricity in PJM and other RTOs to be heavily dependent on the volatile pricing of natural gas. Exhibit TMM-3 provides the dollar per MMBtu at which NYMEX natural gas contracts were traded from 1990 through 2008 along with the volatility of these prices as shown by the standard deviation divided by the mean. As shown in the exhibit, natural gas prices have ranged from a low of approximately $1.00/MMBtu in 1992 to a high of approximately $15.00/MMBtu in 2005.

NYMEX Coal prices have also shown a high degree of volatility. Exhibit TMM-4 provides the dollar per ton at which NYMEX coal contracts were traded from 2001 through October 2009, along with the volatility of these prices as shown by the standard deviation divided by the mean. As shown in the exhibit, NYMEX coal prices have ranged from a low of approximately $23.00/ton in 2002 to a high of approximately $140.00/ton in 2008.

Another component that has potential volatility and can affect the price of electricity is emissions allowances. Based on Clean Air Act Amendments, as well as cap and trade programs, emissions allowances can be used to offset emissions of sulfur dioxide (SO_2) and nitrous oxides (NOx). One emissions credit represents an allowance for every ton of SO_2 emitted, with SO_2 increasing to 2 allowances per ton in 2010, for example. If generating units emit less SO_2 than the allowances awarded, the holder may either sell the allowances, or bank them for future use. Even though the impact of emissions allowance prices on variable production costs may at times be less significant, the volatility of existing allowance prices, and those of potential cap-and-trade programs in the future, along with the impact of those prices on the market must be taken into consideration and managed.

Volatility provides signals for what issues are impacting the cost of electricity now and the expectations of those impacts in the future. However, volatility needs to be evaluated constantly to understand the reasons behind it, and the best means to mitigate its effects. One of the key ways that AEPSC optimizes OSS margins is by anticipating and reacting to the factors that cause volatility. Changes in the input components that might make our surplus energy less competitive in the wholesale market can create opportunities for other areas that contribute to OSS margins, such as trading financial derivatives associated with those inputs.

Q: IN ADDITION TO VOLATILITY, WHAT ARE SOME OF THE OTHER EXAMPLES OF HOW RISK AFFECTS OPERATIONS IN THE WHOLESALE MARKET?

A: Referring to Exhibit TMM-1, other Market Risks include:

Credit Risk. As the transaction will involve two counterparties, there is the risk that the counterparty may not have the ability to pay its obligations. AEPSC employs extensive and stringent credit analysis in order to manage credit risk. AEP's Credit Risk group independently monitors AEPSC's counterparty credit risk exposure on a daily basis.

Counterparty Performance Risk: The counterparty may not be able to deliver on a transaction, such as in the case where an independent power producer's generating facility experiences a forced outage, or transmission congestion may prevent the delivery of contracted energy.

Volumetric Risk: There is volumetric risk associated with unanticipated variations in load, or in the availability of generation. AEPSC manages these variations through its trading activity.

Basis Risk: An additional risk that AEPSC must manage is basis risk. Prices are based at numerous and liquid trading hubs. Thus, the basis risk results from the possibility that the market price will vary as a result of associated congestion costs, for example, between the generation source and the delivery point.

Although this does not constitute an exhaustive list of the risks that are confronted in the wholesale power market, these are the primary risks that AEPSC faces on a daily basis.

Q: HOW HAS AEPSC RESPONDED TO THE CHANGING ENVIRONMENT OF THE WHOLESALE POWER MARKET?

A: Prior to the expansion of the wholesale power markets, AEPSC performed traditional activities such as unit dispatch, accounting, and settlements. However, in the changed environment of the energy market, activities such as unit dispatch and coordination of generation now carry considerable financial consequences.

AEPSC has chosen an integrated approach to the expanding wholesale power market. Instead of creating an entirely separate organization to take on the risks and rewards of the changing markets, AEPSC leverages its operating expertise, in conjunction with traditional knowledge, to enhance the trading activities to provide an optimized benefit. In order to successfully compete against non-traditional market participants and address continuously evolving market conditions, AEPSC has transformed the traditional commercial skill set of those engaged in OSS transactions. The presence of commodity traders, risk management experts, as well as accounting, credit, and legal experts versed in the contractually-based commodity environment makes AEPSC an experienced trading and marketing organization. To enhance this organization, AEPSC has purchased and built risk management, market risk oversight, as well as scheduling and trade capture, information technology systems. AEPSC also uses an independent market risk oversight staff to monitor the daily implementation and adherence to policies and procedures that are governed by the Commercial Operations Credit Risk Policy and Market Risk Policy. As the markets have evolved, the Commercial Operations organization has continuously been structured to meet the ever changing environments of the wholesale power markets.

The different ways in which individual utilities have responded to those external changes also adds additional layers of complexity. AEPSC's structure for Commercial Operations is just one of a variety of ways utilities around the country manage OSS. Many utilities are less active than AEPSC, while others have spun off their trading function into a separate, deregulated entity. As discussed above, AEPSC chose its path based on the optimization of OSS margins through integration. Simply put, the integrated nature of AEPSC's Commercial Operations group produces an organization that is able to incur and manage the risks and rewards associated with today's wholesale power markets.

VIII. The PJM RTO

Q: WOULD YOU PLEASE EXPLAIN HOW AEPSC'S PARTICIPATION IN THE PJM RTO HAS INCREASED THE COMPLEXITY OF PRODUCING OSS MARGINS?

A: Joining PJM has added another layer of complexity to the marketplace in which AEPSC must operate. PJM's operation of AEP's (and other utilities') high voltage transmission system and PJM's dispatch instructions to AEPSC generation units are based on a reliability-constrained, economic approach for the entire PJM footprint. From an operational standpoint, by joining PJM, AEPSC must evaluate more complexities in order to deliver reliability-constrained, reasonably priced electricity for AEP's customers and to optimize OSS margins.

Q: WOULD YOU PLEASE EXPLAIN HOW AEPSC APPLIES THE TRADING AND RISK MANAGEMENT SKILLS IT HAS DEVELOPED TO THE PJM MARKET?

A: AEP applies the risk management techniques it has honed through its trading and risk management activities to its traditional utility operations in PJM in many ways. PJM operates what is referred to as a "two settlement" system. This means that market participants must indicate by noon the day prior to the operating day what their PJM settled load and generation resource mix will be the following day. Companies submitting such a load and resource mix to PJM will receive the results of PJM's reliability-constrained, economic dispatch run and will become financially committed to abide by the price and volume commitments they receive from PJM at 4:00 p.m. on the day prior to the operating day. PJM will then settle with market participants against their day-ahead commitments for volume and price based on their actual volume relative to the price that is realized during the operating day. Hence, the term "two settlement" was created.

An example of the direct application of AEPSC's trading and risk management acumen to operations in the PJM environment would be how AEPSC sets itself up for an operating day. AEPSC must consider where the expected daily bilateral prices are trading for the next day, PJM's expected load forecast relative to AEP's own load forecast, and AEPSC's related expectation of weather for the following day. Further, AEPSC must understand what are the expected availabilities of AEP's generating units, and the impacts of being "short" or "long" in the real time market.

To highlight additional complexity, suppose that AEPSC entered into the operating day with adequate generation, but then lost two large units, driving up the expectation for prices for the balance of the day. Using its trading expertise, and related position management ability, AEPSC could purchase additional energy (length) in the "balance of the day" market in order to minimize the impact of its "short" position.

Q: WHAT ARE SOME OF THE WAYS THAT AEPSC MANAGES ASSETS WITHIN THE COMPLEXITIES OF THE PJM MARKET?

A: OSS margins from PJM markets are not simply the result of bidding all surplus energy that can be sold on an hourly or day-ahead basis into the market. Rather, to optimize margins in this short-term (i.e., hourly or day-ahead) market, AEPSC utilizes its Commercial Operations group to leverage "traditional" utility experience, such as engineers with power plant experience, as well as operations research, financial performance analysts, energy marketing and trading teams, energy market analysts, meteorologists to forecast weather impacts, economists to forecast load/demand, and transmission specialists that can understand physical transmission limitations and congestion. Examples of some issues that are specific to the short-term markets are the: 1) relationship of day-ahead to hourly pricing, 2) risks associated with the loss of generation and load variation, 3) risks associated with unit start-up and shut-down and 4) risks associated with following the PJM dispatch instructions.

Offering in surplus energy related to short-term physical transactions to optimize OSS margin is much more complex than simply offering the units into the PJM market. As I mentioned above, PJM does not dispatch generating units to optimize OSS for AEPSC. The dispatch performed by PJM is designed to reliably serve the load within the entire PJM footprint in a least-cost manner for PJM. Therefore, PJM looks to minimize the cost, but does not sacrifice reliability, across the entire footprint and does not attempt to optimize revenues for individual market participants. It is AEPSC's responsibility to optimize the

Company's margins for OSS. AEPSC must line up all the available resources from a cost standpoint to determine if they will be selected in the market on a daily and forward basis. This is accomplished in multiple ways; traders provide a forward market view, while simulation tools are used to project market prices. All available resources are offered into the market and from time to time some units are scheduled into the market when it is likely that PJM will not select that unit on a day-ahead basis. This guarantees a day-ahead price removing real-time price volatility for the unit, while limiting exposure for an asset that may not receive a day-ahead award, but which may have physical constraints that would make it more costly to actually shut down. AEPSC continually evaluates AEP's generating resources on a rolling weekly basis and beyond to avoid costly shut downs and start-ups to ensure lower overall cost to our customers.

Q: ARE THERE OTHER ACTIVITIES UNDERTAKEN BY AEPSC TO EFFECTIVELY OPERATE WITHIN PJM?

A: Yes. In addition to supplementing PJM's unit commitment process described above, AEPSC analyzes whether or not to hedge against the volatility of real-time prices. This can be accomplished by ensuring that a certain amount of generation is available to capture price spikes in the real-time market. Another type of activity involves optimizing AEP's generation dispatch. Once a generating unit has been committed and is being dispatched in real-time, AEPSC has in place real-time monitoring of dispatch accuracy to ensure plants are performing as requested and our dispatchers are optimizing the value from the inter-hour price volatility. PJM dispatch instructions allow the operator of the generating unit some minimal flexibility around the desired output. By adjusting a unit's energy output to optimize revenue when the market price is greater than operating costs (variable costs plus

PJM operating reserve charges) and by maximizing energy purchases when the market price is less than operating costs, AEPSC is able to create additional value.

Another focus of AEPSC is to ensure the capabilities of the units are accurately reflected in PJM's unit commitment and dispatch process. Units often experience curtailments due to a variety of reasons including equipment failure, environmental restrictions, etc. Understanding and communicating unit limitations is critical because if AEPSC is not able to meet its dispatch obligation, it must purchase energy in the real-time market, which may be at a higher price than what was awarded day-ahead.

Q: WOULD YOU PLEASE EXPLAIN WHAT IS MEANT BY ENERGY AUCTIONS AND HOW AEPSC PARTICIPATES IN THESE AUCTIONS?

A: Energy auctions are competitive procurement processes to secure the lowest possible market price for the load requirement. Energy auctions can be held for utility customers, aggregated groups such as cities, or even entire states. There are a variety of auction types, and different possible contract provisions sought, such as load-following. AEPSC participates in energy auctions both inside and outside of AEP's service territory in both MISO and PJM, in which AEP's generation is not used as a hedge. AEPSC has recently participated in regional procurement processes in Illinois, Maryland, and Ohio. These efforts require the extensive coordinated activities of various parts of AEPSC, such as trading, marketing, fundamentals analysis, and other areas in AEPSC, which include legal, accounting, market risk oversight, and credit analysis in order to formulate an initial bid. AEPSC must analyze the time period of the auction and the requested products for 1) forward capacity and energy prices, 2) load shape and customer migration risks, 3) volatility of other energy and energy-related markets (natural gas, coal, emissions, etc.) and 4) any other events that may influence price. In the event that AEPSC is awarded a portion of the auction load, it must be hedged with market purchases and managed by Commercial Operations. These auction revenues provide additional OSS margins unrelated to AEP's generation, which is incremental positive margin business that AEPSC would forego without the trading-based ability to appropriately price the transaction and offer at a price that locks in the margin. AEPSC manages the risk and benefits of the obligation to deliver energy at a given price in future periods. This activity by the AEPSC is clearly above and beyond simply offering surplus energy into the wholesale power market, and this margin is only made possible by their knowledge of market fundamentals.

Q: WOULD YOU PLEASE EXPLAIN TRADING FOR HEDGING PURPOSES?

A: When AEPSC uses the term "hedging" in regard to its trading activity, it primarily means that it is entering into transactions for which AEPSC has an existing "open" position (i.e., an obligation to purchase or sell energy in the future without a matching obligation in the other direction that protects from effects of change in the price of the asset) and wants to lock in the margin on that position. An example of a hedged transaction would be one in which AEPSC "sells forward" (at an agreed-upon future time) surplus energy that it has for a particular period. In this example, the surplus energy would be AEPSC's "open long" position. By entering into a sale for that same period, AEPSC would be "closing" its position. Hedging is a way to mitigate risk; however, not all risk can be eliminated. For example, in the event that several additional units come off-line during the "hedge" period, AEPSC would have an open position to manage.

Prior to the growth of the wholesale energy markets over the past decade, AEPSC and other utilities would hedge uncommitted generation to some degree, primarily through long-term firm or monthly physical sales to municipal, cooperative, and investor owned utility customers. These physical transactions were often limited by the number and location of counterparties interested in entering into physical transactions at the same time as AEPSC. The development of the financial electricity market has given us a new avenue in which to hedge our generation assets. A new category of financial intermediaries, which includes high credit quality investment banks and hedge funds, are willing and able to enter into financial transactions through electronic trading exchanges, such as the Intercontinental Exchange (ICE[3]). By entering into such transactions and by employing proper trading-based risk management and accounting treatment, AEPSC is able to financially sell forward surplus energy to counterparties.

An example of this occurred in late 2005, when electricity prices were driven up due to natural gas prices and supply disruptions associated with hurricanes Rita and Katrina. AEPSC saw the 2006 on-peak price for power in the AEP/Dayton trading hub (a key price reference point) increase from $63/MWh before the hurricanes to a high of $79/MWh. AEPSC wanted to sell some of its surplus energy for certain periods of the 2006 on-peak period, but had only limited opportunities to do so through traditional physical customers. By employing position management techniques, AEPSC was able to determine particular quantities during particular periods that it desired to hedge. AEPSC then availed itself of the financial swap market on ICE to hedge surplus energy. The hurricane related price increases receded, but AEPSC was able to realize margins associated with the higher prices because AEPSC engaged in this financial hedging. Had AEPSC not financially hedged its generation forward and simply sold its generation at current lower spot prices, it would have realized lower margins.

[3] Intercontinental Exchange (ICE) is a leading electronic marketplace for energy trading and price discovery. ICE allows market participants direct access to energy futures and Over-the-Counter commodity products for oil and refined products, natural gas, power and emissions.

Q: WHAT ARE SOME OTHER OPPORTUNITIES WHERE AEPSC IS ABLE TO USE TRADING TO RESPOND TO PRICE ANOMALIES?

A: An example would be a trade related to market fundamentals that AEPSC might enter into based on observations about an upcoming outage season. In the past, AEPSC has observed that during a particular outage season, not only did AEP have significant outages planned, but that other generators also had significant planned outages. AEPSC compared market prices for that season to previous outage seasons and believed that the market price of electricity for the planned outage season did not adequately reflect the amount of capacity expected to be unavailable (i.e. AEPSC believed the current price of power for that period was lower than what would normally be expected during the outage season). AEPSC bought forward financial power and realized positive margins on the trade when future prices rose as AEPSC had anticipated.

Q: ARE THERE SOME ADDITIONAL BENEFITS OF THESE TRADING ACTIVITIES?

A: An additional benefit of AEPSC's trading activity that distinguishes it from the physically based activity of the past is that this activity affords greater opportunity to respond to changing market conditions. If AEPSC had to rely only on physical transactions, the universe of potential counterparties would be greatly diminished, as would the ability to quickly change positions (from being long to being short or flat and vice versa). Ultimately, AEPSC's trading activity provides incremental positive margin that would not be available without the capabilities of its Trading and Marketing group.

AEPSC believes that its physical positions of generation and purchased resources ("length") and load and sales commitments ("shorts") provides its traders with unique insights into the fundamentals of its own footprint as well as surrounding areas. AEPSC believes by employing that fundamental insight it can make better and quicker judgments about the movement of the prices of forward electricity than can counterparties without such insights. Traders also consider a wide range of additional data in other regions and in areas such as new construction, unit efficiencies, environmental regulations, weather trends, and economic conditions in order to analyze the markets and devise appropriate trading strategies.

AEPSC also uses the same resources to secure power from the spot energy market, which is required periodically to meet native load. Power purchased from the market is used to serve native load customers when the cost of the purchase is less than the variable cost of AEP's internal generation. AEPSC makes targeted purchases from the market that directly benefits the Company's customers. Through its Trading group, AEPSC both buys and sells electricity at wholesale. Because AEPSC participates in the market for both purposes, AEPSC's intentions to other market participants are unclear. This means that when AEPSC needs to purchase for its native load customers, there is not a clear sign to the market that AEPSC is in an unfavorable position and needs to buy at any price. In such instances, AEPSC's ability to "buy better" enables it to keep its purchased power cost as low as possible. By contrast, when AEPSC is selling in the market, since AEPSC sells for both hedging and purely trading reasons, it is unclear to other market participants whether AEPSC is hedging a significant amount of generation, or simply adjusting a trading position. This lack of a clear market signal to other market participants allows AEPSC to gain additional OSS margins compared to an energy company with surplus energy that is only a seller in the wholesale electricity markets.

IX. CONCLUSION

Q: WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A: Yes. The existing wholesale power market has introduced additional risks into many parts of the utility business. The proposed change in the system sales clause helps insulate customers from some of those risks by assuring they receive credit for at least $7,645,182 in OSS margins without regard to whether those margins are ever realized. In addition, unlike the current system sales clause, customers do not share in any shortfall in OSS margins below the test year amount.

Further, although AEP has proactively created Commercial Operations to actively manage these risks, there are still many risks within the wholesale power markets that are beyond the control of the Company. Therefore, to actively meet the challenges posed by these risks, AEP must determine an optimal balance between market risks and rewards. The proposed modification to the current system sales clause achieves this balance.

OSS can potentially be a large component of revenue, and, as the recent economic downturn has shown that although Commercial Operations' Trading & Marketing group actively manages the risk associated with the wholesale power market, there are still many factors that are beyond the control of the utility. The proposed modification helps to better shield KPCo's customers and the Company against the volatility of OSS margins, and provides a better balance between risks and rewards of the wholesale power markets. In addition, the Company continues to have an incentive to optimize OSS margins and extract the fullest value possible from its assets and the trading and marketing group by diligently pursuing the opportunities presented in the vibrant wholesale market for electricity. Moreover, KPCo customers receive an increased benefit from the opportunities for OSS margins while remaining protected from any negative outcomes. And finally, the Company's financial health is protected from the potentially material earnings swings that are an inherent risk in this volatile, rapidly changing environment, potentially helping to avoid or delay future rate increases that would otherwise be caused due to increased costs of providing service.

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

A: Yes.

AFFIDAVIT

Thomas M. Myers, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Thomas M. Myers

State of Ohio)
)ss
County of Franklin)

Subscribed and sworn to before me, a Notary Public, by Thomas M. Myers this 17th day of December 2009.

Notary Public

CHERYL L. STRAWSER
NOTARY PUBLIC, STATE OF OHIO
MY COMMISSION EXPIRES 10-01-11

My Commission Expires 10/01/2011

Different Types of Risk Managed by AEP

Market Risk

Potential fluctuations in prices, volumes exchanged, and market rules that may affect a company's buying and selling activities. Usually, this is composed of:

- **Price risk**
  Potential fluctuations in prices of the underlying energy commodity
- **Credit risk**
  Potential adverse occurrence of a counterparty's ability to pay its obligations
- **Counterparty performance risk**
  Potential adverse occurrence of a counterparty's ability to operationally perform on an agreement or obligation
- **Volumetric risk**
  The risk that commodity volumes will vary from expected volumes and result in a potential loss due to changing commodity market prices. For example, a generating unit sells projected electric generation production forward and at the time of delivery a unit is forced out and cannot deliver. This results in a loss if the price to purchase electricity to cover the sales is higher than the electricity sale price.

Basis Risk

There are various types of basis risk and are generally due to differences in:

- **Geography** - locational
- **Quality** (Product) – mismatch in type or quality of hedge and underlying
- **Delivery**
- **Time** or calendar

Liquidity Risk

Exposure to the inability to effectively/timely liquidate open positions in the marketplace

Execution Risk

The potential for an extra cost in completing an order to buy or sell. Typically, this may include a slippage in price received or paid between when the strategy is communicated and when the final transaction occurs, the cost of not exercising an option, the internal cost of executing a transaction, or the failure to perform according to the contract.

RTO Risk

Risks associated with understanding existing and changing market rules

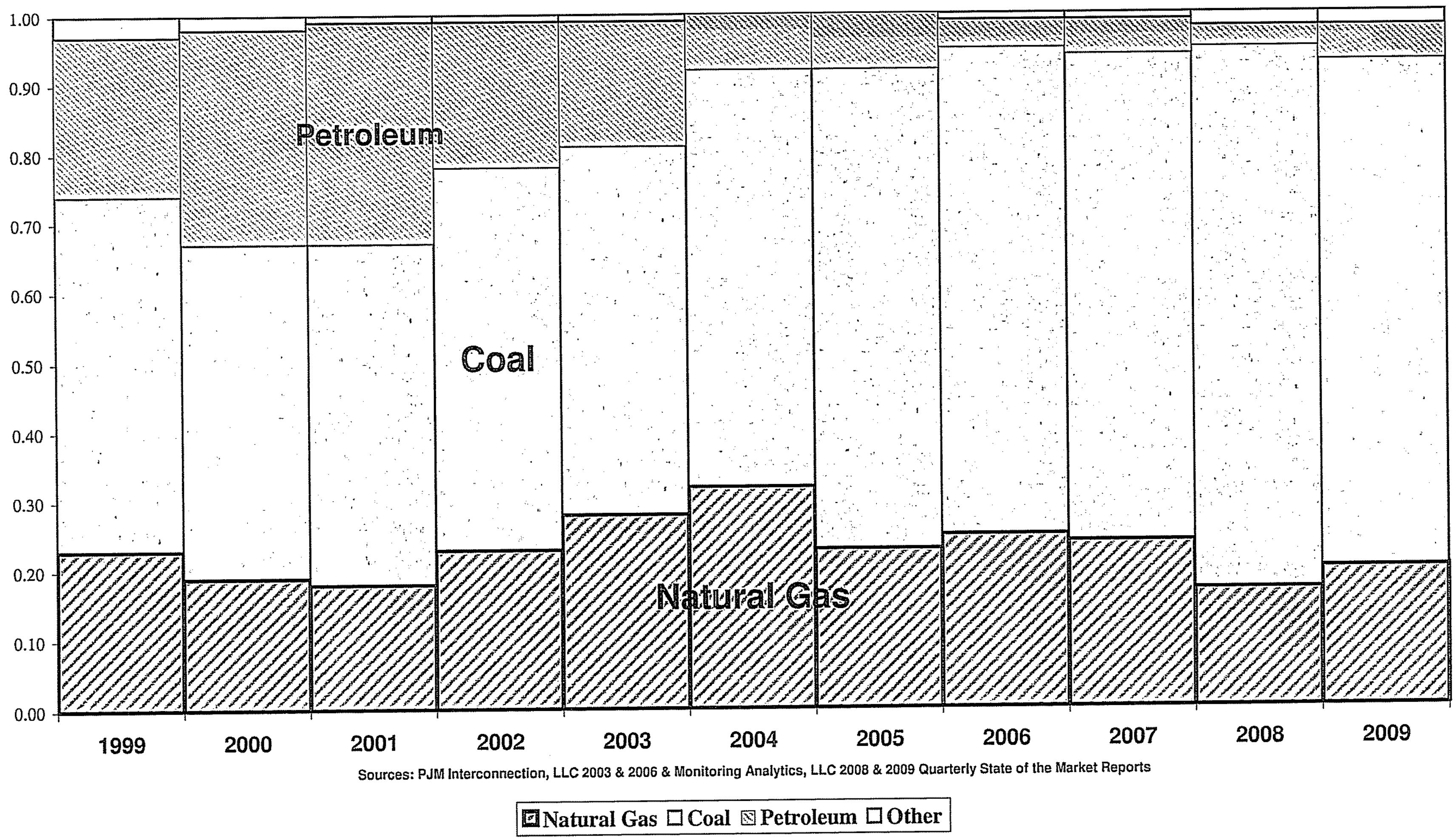
Operations Risk

The risks associated with physical asset or delivery of energy commodities

- **Plant availability** – major component failure
- **Available transmission capability**

Type of Fuel Used by Marginal PJM Unit (January 1999 - September 2009)

Sources: PJM Interconnection, LLC 2003 & 2006 & Monitoring Analytics, LLC 2008 & 2009: Quarterly State of the Market Reports



Sources: PJM Interconnection, LLC 2003 & 2006 & Monitoring Analytics, LLC 2008 & 2009 Quarterly State of the Market Reports

Exhibit TMM-3

Historical Price of NYMEX Natural Gas Contracts and Volatility (April 1990-October 2009)

Source Data: NYMEX Henry Hub Natural Gas Futures (USD/MMBTU): Pit Session

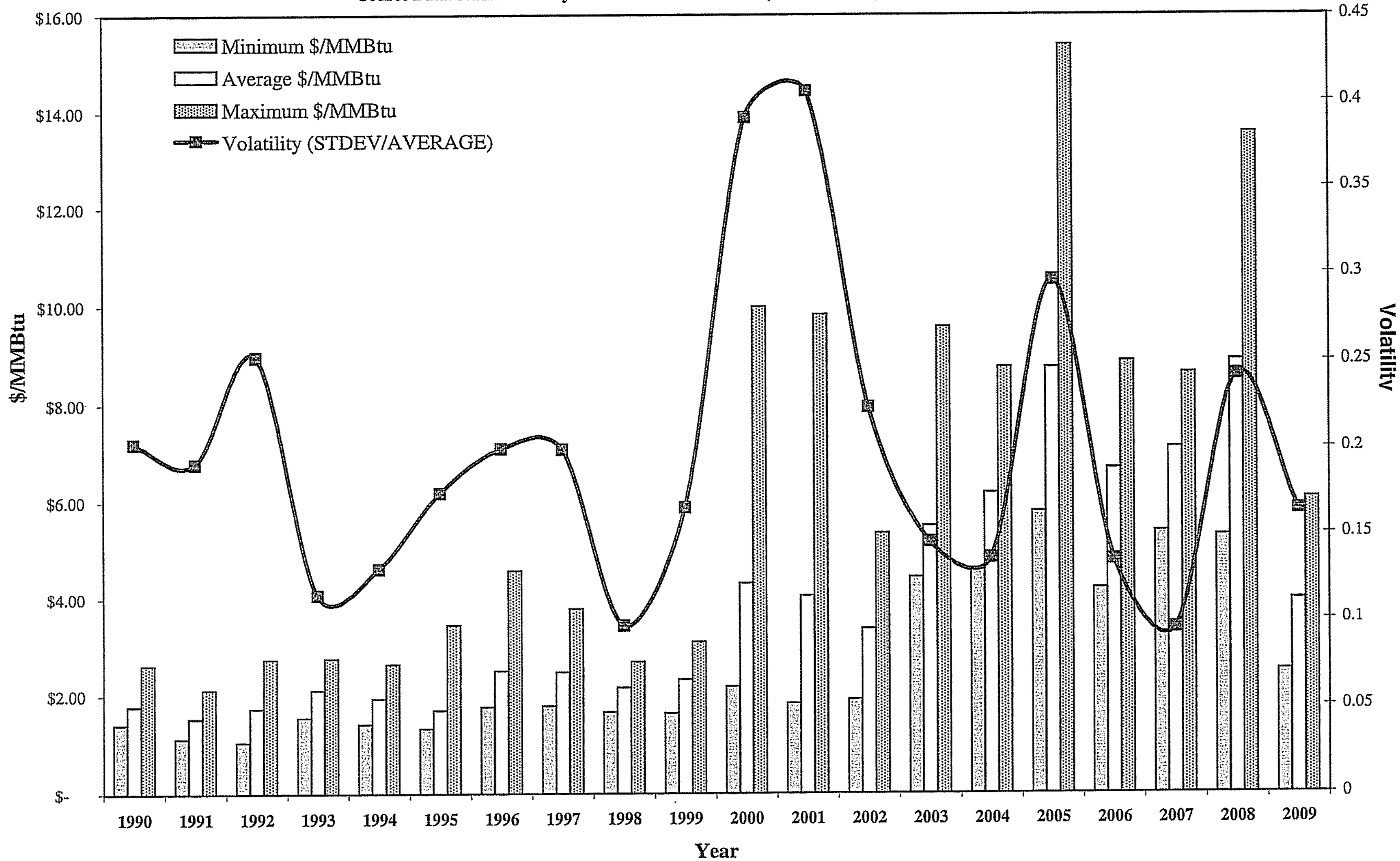


Exhibit TMM-4

Historical Price of NYMEX Coal Contracts and Volatility (July 2001-October 2009)

Source Data: NYMEX Central Appalachian Coal Futures (USD/TN): Clear Port