COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2008-00409**

TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: October 31, 2008

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and depreciation studies.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of East Kentucky Power Cooperative, Inc. ("EKPC").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to present the financial summary and supporting exhibits detailing how EKPC derived the amount of the requested revenue increase, (ii) describe EKPC's proposed pro-forma revenue, expense, and rate base adjustments, (iii) describe the calculation of EKPC's adjusted net margin and revenue deficiency for the fully forecasted test period ended May 31, 2010, (iv) describe the calculation of the 13-month average of EKPC's rate base and capitalization for the fully forecasted test period; (v) to sponsor the fully allocated class cost of service studies based on EKPC's cost of providing service for the 12 months ended May 31, 2010; and (vi) to support EKPC's proposed wholesale rates to its members.

Q. Please summarize your testimony.

A. EKPC is proposing a rate increase which is designed to produce additional revenues of approximately $67.9 million. EKPC's proposed rate increase is supported by a fully forecasted test period corresponding to the 12 months ended May 31, 2010. The level of the increase is supported by an analysis of EKPC's revenue deficiency based on the pro-forma financial results for the forecasted test period. EKPC's revenue requirement was determined based on net margin requirements necessary to produce a 1.45 Times Interest Earned Ratio ("TIER"). The $67.9 million proposed increase, which was approved by EKPC's Board of Directors, is less than the $70.0 million revenue deficiency determined using a 1.45 TIER.

EKPC's proposed rates will allow it to begin gradually rebuilding its equity, which is currently at a dangerously low level. EKPC's equity as a percentage of total capitalization is expected to drop to around 6.8 percent prior to the implementation of the new rates. It is important to realize, however, that even with the new rates, EKPC's equity as a percentage of total capitalization is projected to only be 9.67 percent in December 2011, which will still not be adequate. One of the main reasons that its equity position will not improve more than this is because EKPC will continue to add assets to its balance sheet in support of its effort to install sufficient generation facilities to meet the needs of its members.

A class cost of service study was performed for the purpose of assisting EKPC in designing its proposed rates. In order to transition to cost-based rates, EKPC is proposing a phased-in approach consisting of *Phase I* rates – which would be placed into effect upon approval by the Kentucky Public Service Commission ("Commission"), which presumably will be at the end of the suspension period in this proceeding, and "Phase II" rates – which would go into effect 12 months later. Although both Phase I and Phase II rates are designed to produce approximately the same overall revenue, the proposed Phase II rates include unit charges that more accurately track the results of the cost of service study.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

Filing Requirement	Description	Volume	Tab #
Section 10(8)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	Vol. 1	Tab 20
Section 10(8)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	Vol. 1	Tab 21
Section 10(9)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	Vol. 2	Tab 23
Section 10(9)(v)	Cost of service study based on methodology generally accepted in the industry and based on current and reliable data from a single time period.	Vol. 5	Tab 44

Filing Requirement	Description	Volume	Tab #
Section 10(10)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	Vol. 5	Tab 46
Section 10(10)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of rate base.	Vol. 5	Tab 47
Section 10(10)(h)	Computation of revenue conversion factor for forecasted period	Vol. 5	Tab 53
Section 10(10)(l)	Narrative description and explanation of all proposed tariff changes	Vol. 5	Tab 57
Section 10(10)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes	Vol. 5	Tab 58
Section 10(10)(n)	Typical bill comparison under present and proposed rates for all customer classes	Vol. 5	Tab 59

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Revenue Requirements, (IV) Cost of Service Study, and (V) Rate Design.

II. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville

Gas and Electric Company. From May 1979 until December 1990, I held various positions within the Rate Department of Louisville Gas and Electric Company. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left Louisville Gas and Electric Company in July 1996 to form The Prime Group, LLC, with another former employee of the Company. Since then, we have performed cost of service studies, developed revenue requirements and designed rates for well over 130 investor-owned, cooperative and municipal utilities across North America. A more detailed description of my qualifications is included in Seelye Exhibit 1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified in over 45 regulatory proceedings in 11 different jurisdictions regarding revenue requirements, cost of service and rate design. A listing of my testimony in other proceedings is included in Seelye Exhibit 1.

Q. Have you performed cost of service studies and developed rates for electric cooperatives?

A. Yes. I have performed cost of service studies and developed rates for a number of generation and transmission cooperatives ("G&T cooperatives"), including Hoosier Energy, South Mississippi Electric Power Association, Big Rivers Electric Corp, Southern Illinois Power Cooperative, Corn Belt Power Cooperative, and EKPC. I have also supervised the preparation of cost of service studies and the development of rates for over 130 electric distribution cooperatives.

III. REVENUE REQUIREMENTS

Q. Please describe how EKPC's proposed revenue increase was determined?

A. EKPC is proposing a general adjustment in rates supported by a fully forecasted test period. The proposed revenue increase is supported by an analysis of the revenue deficiency based on financial results for the forecasted test period. The revenue deficiency was determined as the difference between (i) EKPC's adjusted net margins for the forecasted test period without reflecting a general adjustment in rates, and (ii) EKPC's net margin requirement necessary to provide a 1.45 TIER. Based on the forecasted test year, the revenue deficiency is $70,041,960. EKPC's proposed wholesale rates to its members are projected to produce increased revenues of $67,858,922 based on estimated billing determinants for the forecasted test year.

Q. Why is the proposed revenue increase of $67,858,922 less than EKPC's revenue deficiency of $70,041,960?

A. The rates that EKPC is proposing in this proceeding were approved by EKPC's Board of Directors on September 9, 2008. However, the rates were developed using preliminary revenue requirement and billing determinant estimates which indicated that the revenue requirement was approximately $67.7 million based on a forecasted test period for the 12 months ended April 30, 2010, rather than the 12 months ended May 31, 2010, used in the rate case filing. Because EKPC was unable to file the rate case application until the end of October 2008, the forecasted test year utilized in the rate case filing had to be delayed by one month in order to meet the requirement set forth in KRS 278.192 that the forecasted test period must correspond to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. When EKPC finalized the revenue requirement using costs for the fully forecasted test period that had to be utilized in this proceeding, the revenue requirement turned out to be $70.0 million rather than $67.7 million. Likewise, when the rates that were approved by the Board of Directors were applied to test-year billing determinants, the revenue increase turned out to be $67.9 million rather than the $67.7 million amount indicated in the Board resolution provided as an exhibit to Mr. Marshall's testimony. Because the proposed revenue increase is less than the revenue deficiency determined based on operating results for the fully forecasted test period, EKPC made the decision not to revisit the issue with its Board of Directors for the purpose of obtaining approval to propose a larger increase with the Commission. Particularly, EKPC decided to maintain its proposed rates in this proceeding at the level approved by its Board of Directors even though a higher revenue increase could be supported.

Q. Why did EKPC choose to support the proposed rate increase with a fully forecasted test period?

A. As the Commission is well aware, EKPC has been in financial distress since 2005. Its interest and debt coverage ratios are forecasted to be inadequate to meet the requirements set forth in the mortgage and credit facility agreements with its lenders. Without a rate increase, EKPC's financial condition will deteriorate even further once Spurlock 4 is placed into commercial operation. Considering its dangerously low level of equity capital, without increasing its rates it would be difficult for EKPC to withstand the stress of an unanticipated expense, such as expenditures that might result from an unanticipated equipment failure at one of its generating stations. Spurlock 4, a 278 MW coal-fired generating unit which will cost approximately $528 million, is scheduled to be placed into commercial operation on April 1, 2009. None of the cost of Spurlock 4 is currently in rate base. EKPC has not included the Construction Work In Progress ("CWIP") for Spurlock 4 in rate base. Because it has been accruing an Allowance for Funds Used During Construction ("AFUDC") on its construction expenditures, EKPC is currently not recovering interest expenses associated with Spurlock 4 through rates. Once Spurlock 4 is placed into commercial operation, EKPC will experience a significant increase in its non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses. Although Spurlock 4 will result in fuel and purchased power cost savings, those savings will be automatically passed along to its members through the application of the monthly fuel adjustment clause. Therefore, the fuel cost savings will not off-set the impact on EKPC's net income from placing Spurlock 4 in service.

With that background, it is easier to understand why EKPC is supporting its rate increase with forecasted test period costs. If EKPC were to use a historical test year, the very earliest that any of the costs of Spurlock 4 would be reflected in historical test period costs would be in April 2009. EKPC simply could not wait until after April 2009 to file a rate case application, which would not provide additional revenues to cover the increased costs of Spurlock 4 until approximately nine months later. Even though EKPC has never filed a fully forecasted rate case, it was critical that the company move forward with a forecasted rate case considering the serious consequences of not being able to adjust its rates until after April 1, 2009. In its Order in Case No. 2006-00472 dated December 5, 2007, the Commission directed EKPC to file its next base rate case when conditions warrant. Given EKPC's precarious financial circumstances, conditions warrant filing a rate case utilizing a forecasted test year that provides increased revenues to cover the additional costs associated with Spurlock 4.

Q. What are the forecasted test period and the base period for the rate case application?

A. The *forecasted test period* for the filing is the 12 months ended May 31, 2010. Consistent with KRS 278.192, the forecasted test period used to determine revenue requirements in this proceeding corresponds to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. According to KRS 278.190, the maximum suspension period is six months for a general adjustment in rates supported by a fully forecasted test period. Because the effective date of the EKPC's proposed rates is December 1, 2008, the first 12 consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning June 1, 2009, and ending on May 31, 2010.

The *base period* for the filing is the 12 months ended January 31, 2009. The base period consists of seven months of actual historical data and five months of estimated data. KRS 278.192(2)(a) requires that any rate case application utilizing a forecasted test period must include a base period which begins not more than nine months prior to the date of the filing, and consisting of not less than six months of actual historical data and not more than six months of estimated data. Because EKPC's proposed base period, which begins February 1, 2008, includes more than six months of actual historical data, includes less than six months of estimated data, and begins less than nine months prior to the October 31, 2008 filing date in this proceeding, its proposed base period is in compliance with the requirements for a forecasted test year set forth in KRS 278.192(2)(a).

Q. Why didn't EKPC file its rate case using a fully forecasted test period beginning April 1, 2009, rather than June 1, 2009?

A. Because EKPC is a member-owned G&T cooperative, preparing a rate case involves considerably more steps than for either an investor owned utility or a distribution cooperative. EKPC had to build in enough time to prepare its financial budget incorporating accurate and up-to-date construction cost estimates for Spurlock 4 and other projects, present the proposed financial budget and wholesale rates to its member systems, obtain EKPC Board approvals for its financial budget and proposed rates, develop pass-through rates for its member systems in accordance with the provisions of KRS 278.455, and then provide enough time for the boards of its member systems to approve their individual pass-through rates and publish their individual statutory notices in newspapers across the state. As it turned out, there was simply not enough time between preparing the financial budget incorporating updated construction cost estimates and publishing the member systems' statutory notices that would have allowed EKPC to file a rate case application with rates to be effective six months prior to the suspension period for a forecasted test year.

Q. **Given that EKPC's proposed rates would not go into effect until June 1, 2009, won't there be two months when its rates will be unable to provide recovery of the increased costs associated with Spurlock 4?**

A. Yes. The fact that EKPC will not be able to offset its increased non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses associated with Spurlock 4 with additional revenues will cause its net margin for April and May, 2009, to deteriorate sharply. The inability to recover Spurlock 4 carrying charges for those two months would have a significant adverse effect on EKPC's fiscal 2009 financial results. Without some sort of rate recovery mechanism to deal with this short-fall, EKPC will never be able to recover these fixed charges, which represents a serious problem for a utility whose interest and debt coverage ratios are dangerously low and whose equity percentage is projected to be only 6.8 percent during April and May, 2009.

Q. **How is EKPC proposing to address these uncollected costs associated with Spurlock 4?**

A. As described in greater detail in the *Motion for the Creation of a Regulatory Asset Relating to Spurlock Unit 4 Expenses* that is being filed in this proceeding, EKPC is proposing to establish a regulatory asset that would allow it to record the additional revenue that it would have collected in April and May, 2009, if EKPC's new rates would have gone into effect on April 1, 2009, rather than on June 1, 2009. In other words, EKPC would record the additional revenues that would have been billed through the application of the new rates during April and May 2009 in a deferred debit (Account No. 182.4). The amount ultimately recorded as a regulatory asset in Account No. 182.4 would correspond to the billing difference in April and May 2009, (based on forecasted billing determinants) between the rates ultimately approved by the Commission (without the amortization of the regulatory asset) and EKPC's current rates. Therefore, the ultimate amount recorded as a regulatory asset would be based on the rates that the Commission ultimately authorizes in the rate case order, without considering the amortization of the regulatory asset. The regulatory asset – whatever the amount turns out to be – would be amortized over three years and reflected in the final rates approved by the Commission.

As an alternative to setting up a regulatory asset to provide recovery of the unbilled Spurlock 4 carrying charges, the Commission could waive its six-month *maximum* suspension period applicable to rate applications using a forecasted test period and allow EKPC to place its proposed rates into effect on April 1, 2009, subject to refund. Because this alternative could possibly require that EKPC's member systems make refunds to their retail members, allowing EKPC to establish a regulatory asset would represent a simpler approach.

Q. Have you prepared an exhibit that shows how EKPC's revenue deficiency is calculated?

A. Yes. Seelye Exhibit 2 shows the calculation of EKPC's revenue deficiency.

Q. Please walk us through Seelye Exhibit 2.

A. The purpose of Seelye Exhibit 2 is to calculate the difference between EKPC's adjusted net margin (deficit) for the forecasted test year and the margin necessary for EKPC to achieve a 1.45 TIER. The exhibit starts out with Operating Revenue and Patronage Capital from EKPC's budget for the 12 months ended May 31, 2010 (line 1). This amount is obtained from the 2009 and 2010 budgets that were approved by EKPC's Board of Directors. EKPC's Board is comprised of a board member from each of its 16 member systems. The monthly and 12-month total budget amounts for the forecasted test year are shown in Exhibit 1 to Mr. Eames's testimony. A number of pro-forma adjustments are applied to Operating Revenue. The pro-forma revenue adjustments are shown on lines 4 through 7 of the exhibit. EKPC's Adjusted Revenue, as adjusted to reflect the four pro-forma revenue adjustments, is shown on line 9.

The Total Cost of Service from EKPC's budget is shown on line 12. In the context of EKPC's budget and financial reports, Total Cost of Service includes operation expenses, maintenance expenses, depreciation and amortization expenses, taxes, interest expenses on long-term debt, other interest expenses, and other deductions. Total Cost of Service is then adjusted to reflect pro-forma adjustments shown on lines 15 through 31 of the exhibit. Adjusted Cost of Service, which reflects the pro-forma expense adjustments, is shown on line 34. Adjusted Operating Margins (line 36) is calculated by subtracting Adjusted Cost of Service (line 34) from Adjusted Revenue (line 9). Interest income (line 39), other non-operating income (line 40), and other capital credits/patronage dividends (line 41) are added to Adjusted Operating Margins (line 36) to determine EKPC's Adjusted Net Margin (Deficit). For the forecasted test-period, EKPC is projected to a have an Adjusted Net Deficit of -$25,603,606 (line 46).

The Revenue Deficiency is calculated on page 2 of Seelye Exhibit 2. To achieve a 1.45 TIER, EKPC needs a net margin requirement of $44,438,354. EKPC's $70,041,960 revenue deficiency corresponds to the difference between this net margin requirement of

$44,438,354 and EKPC's adjusted net deficit of -$25,603,606 (calculated as $44,438,354 - (-$25,603,606) = $70,041,960).

Q. Why was a 1.45 TIER used to determine EKPC's revenue requirement?

A. As explained in the prepared direct testimonies of David G. Eames, Jonathon Andrew Don, and Daniel M. Walker, a 1.45 TIER is in line with what other investment-grade G&T cooperatives are earning and is necessary to provide EKPC with an opportunity to maintain its financial integrity, to maintain adequate interest and debt service coverage ratios, and to rebuild its members' equity to a level that will allow EKPC to continue to attract capital on reasonable terms and to serve its members in a safe and reliable manner.

Q. Please explain why it is necessary to make pro-forma adjustments to financial results from EKPC's budget.

A. It was necessary to make a number of pro-forma adjustments to eliminate costs and associated revenues that are recovered through the fuel adjustment clause (FAC) and the environmental surcharge. A number of other adjustments were required to eliminate expenses that are generally not allowed to be recovered through service rates of utilities in Kentucky that are regulated by the Commission. Two other adjustments were required to amortize or re-amortize certain extraordinary expenses. One final adjustment was required to normalize generation overhaul expenses so that forecasted test-year expenses will be representative on a going forward basis. Support for each adjustment is contained in Schedules 1.01 through 1.18 of Seelye Exhibit 2. The pro-forma adjustments are identified as follows:

(a) Eliminate costs recoverable through the FAC and associated revenues (Schedules 1.01, 1.03).

(b) Remove the impact of revenues and expenses included in the environmental surcharge (Schedules 1.02, 1.04, 1.05, 1.06, 1.07, 1.08).

(c) Eliminate expenses normally excluded by the Commission (Schedules 1.09, 1.10, 1.11, 1.12, 1.13, 1.14, 1.15).

(d) Amortize extraordinary expenses (Schedules 1.16 and 1.17).

(e) Normalize overhaul expenses (Schedule 1.18)

Q. Please describe the adjustments necessary to eliminate expenses and associated revenues related to the fuel adjustment clause.

A. EKPC is proposing to eliminate all fuel and purchased power expenses that would be recoverable through the FAC, the fuel cost revenue associated with base fuel cost component of the FAC, and projected FAC billings. In other words, EKPC is proposing to remove all fuel cost and fuel cost revenues that would be considered in the application of the FAC, including fuel costs recovered through the base rate component which is collected through base rates. Specifically, adjustments were made to remove fuel cost revenue recovered through base rates (Schedule 1.01), to remove FAC revenue (Schedule 1.01), to remove fuel expenses recoverable through the FAC (Schedule 1.01), and to remove purchased power expenses recoverable through the FAC (Schedule 1.03).

Q. Please describe the adjustments to eliminate expenses and associated revenues related to the environmental surcharge.

A. EKPC is proposing to eliminate all environmental costs that would be recoverable through the environmental surcharge and associated environmental surcharge revenue. Specifically, adjustments were made to remove environmental surcharge revenue (Seelye Exhibit 2, Page 1 of 2, line 6), to adjust off-system sales environmental surcharge revenue (Schedule 1.02), to remove operation and maintenance expense recoverable through the environmental surcharge (Schedule 1.04), to remove emissions allowance expense recoverable through the environmental surcharge (Schedule 1.05), to remove property taxes and property insurance recoverable through the environmental surcharge (Schedule 1.06), to remove depreciation expense recoverable through the environmental surcharge (Schedule 1.07), and to remove interest expense recoverable through the environmental surcharge (Schedule 1.08). Because EKPC budgets these revenues and expenses individually they were readily identified from the budget for purposes of removing them from the calculation of the revenue deficiency. EKPC is not proposing any roll-in of environmental costs into base rates in this proceeding.

Q. Please explain the adjustment to off-system sales environmental surcharge revenue (Schedule 1.02) in greater detail.

A. In determining the environmental surcharge, a portion of EKPC's environmental compliance costs recovered through the surcharge are allocated to off-system sales. However, by including off-system revenues in test-year operating results, off-system revenues are credited to jurisdictional customers. This results in an overstatement of margins from off-system sales and a mismatch of the revenues and expenses related to the off-system sales portion of the allocated environmental surcharge monthly revenue requirement. Therefore, consistent with the Commission's orders in the most recent rate cases filed by Louisville Gas and Electric Company and Kentucky Utilities Company, an adjustment was made to reduce revenues to reflect the environmental surcharge methodology for allocating environmental costs to off-system sales. (Order in Case No. 2003-00433 , pp 24-25 and Appendix F and Order in Case No. 2003-00434, p. 24 and Appendix F.)

Q. Please explain the adjustment to remove promotional advertising shown in Schedule 1.09.

A. Pursuant to 807 KAR 5:016, this adjustment eliminates Touchstone Energy advertising and other promotional items included in EKPC's budget for the forecasted test year. These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please explain the adjustment to remove certain directors' expenses shown in Schedule 1.10.

A. Consistent with the Commission's Order in Case No. 2006-00472, EKPC is removing a portion of directors' expenses from the forecasted test-year revenue requirement. The items not removed include the following: fees for regular board meetings, chair and secretary fees, committee chair fees, audit committee chair fees, two special board meetings for each member, fees for training seminars, and expenses of $25,000 for the test year. A total of $93,300 of directors' expenses has been removed from test-year operating expenses.

Q. Please describe the adjustments to remove donations in Schedule 1.11, affiliate expenses in Schedule 1.12, lobbying expenses in Schedule 1.13, Touchstone Energy dues in Schedule 1.14, and Miscellaneous Expenses in Schedule 1.15.

A. Consistent with Commission practice, all donations, contributions, and sponsorships are removed from test-year expenses in Schedule 1.11. All affiliate expenses related to Alliance for Cooperative Energy Services (ACES) Power Marketing, Envision Energy Services, LLC, and the propane gas program for members are removed from test-year expenses in Schedule 1.12. It should be noted, however, that fees paid to ACES for their power marketing functions on behalf of EKPC have not been removed from revenue requirements in this proceeding. Consistent with the procedure followed in its last rate case application in Case No. 2006-00472, EKPC is removing lobbying expenses (Schedule 1.13), Touchstone Energy dues (Schedule 1.14), and certain employee-related expenses (Schedule 1.15). These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please describe the adjustment to reflect an amortization of rate case expenses in Schedule 1.16.

A. This adjustment is necessary to include amortization of the expense incurred in conjunction with this rate case. It is consistent with similar adjustments in revenue requirements found reasonable in numerous rate case orders issued by the Commission, including the Commission's Order approving the settlement agreement in Union Light, Heat and Power Company's recent rate case, which was supported by a fully forecasted test period. (In its Order in Case No. 2006-00172 dated December 21, 2006, the

Commission affirmed that the accounting and ratemaking treatments to which the parties stipulated in the settlement agreement, including the amortization of rate case expenses over 3 years, "generally reflect the approach the Commission has followed in previous rate cases", pp. 4 and 8.)

Q. Please explain the adjustment to reflect the amortization of the 2004 forced outage balance in Schedule 1.17.

A. In Case No. 2006-00472, the Commission determined that it was appropriate to amortize $20,514,346 of expenses related to a 2004 Spurlock 1 forced outage over a 3-year period. As of the beginning of the forecasted test period on June 1, 2009, EKPC will have amortized $10,257,173, or one half of the original amount, leaving a balance of $10,257,173. EKPC is proposing to amortize the remaining balance of $10,257,173 over three years, resulting in an increase in expenses of $3,419,058.

Q. Please explain the adjustment to normalize generation overhaul expenses in Schedule 1.18.

A. This adjustment is necessary to ensure that forecasted test-year expenses will be representative on a going forward basis. During the forecasted test period, EKPC's overhaul expenses are less than the normal level that would be incurred annually by the company. EKPC projects that it will incur $4.8 million in overhaul expenses during the forecasted test year ($2.1 million for Cooper Unit 1 and $2.7 million for Dale Units 1 and 2) compared to an average annual expense of $7.1 million. For the steam generating units, the boiler and generators are overhauled on a 10-year cycle, and the combustion turbines are overhauled on a six-year cycle. The $7.1 million average overhaul expense was calculated by dividing the estimated cost of a boiler/generator overhaul for each steam generating unit in 2009 dollars by 10 years to determine the average amount for the unit, and by dividing the estimated cost of a generator overhaul for each combustion turbine in 2009 dollars by 6 years to determine the average amount for the unit. Therefore, EKPC is proposing a normalization adjustment of $2.3 million, which represents the difference between $4.8 million amount budgeted for the test year and the $7.1 million average level.

Q. Have you prepared exhibits showing the development of the 13-month average rate base and capitalization for the forecasted test year.

A. Yes. Seelye Exhibit 3 shows the development of the 13-month average rate base for the test year, and Seelye Exhibit 4 shows the development of the 13-month average capitalization for the test year. In Seelye Exhibit 3, rate base is shown both with and without environmental assets for which costs are recovered through the environmental surcharge. These environmental assets have been removed from capitalization in Seelye Exhibit 4. It should be noted that EKPC's revenue requirement was determined using a 1.45 TIER, which is an approach that is often utilized by cooperative utilities, rather than a rate of return on rate base or a rate of return on total capitalization, which is used by investor-owned utilities in Kentucky.

Q. Have you prepared an exhibit that shows key financial performance measurements for EKPC with and without the proposed increase?

A. Yes. Seelye Exhibit 5 shows TIER, debt service coverage ratio (DSC), rate of return on net cost rate base, and rate of return on total capitalization for the forecasted test year with and without the proposed increase. The following table summarizes the financial measurements calculated in Seelye Exhibit 5:

FINANCIAL MEASUREMENT	WITHOUT RATE INCREASE	WITH PROPOSED INCREASE
Times Interest Earned Ratio (TIER)	0.74	1.43
Debt Service Coverage Ratio (DSC)	0.81	1.25
Rate of Return on Net Cost Rate Base (ROR)	3.17%	6.19%
Rate of Return on Total Capitalization (ROI)	3.16%	6.16%

It should be noted that the financial measurements shown in this table are calculated using EKPC's proposed revenue increase of $67,858,922 rather than the $70,041,960 revenue deficiency amount necessary to produce a TIER of 1.45. Because EKPCs Board approved increase is used instead of the revenue deficiency, the TIER shown above is slightly lower than the 1.45 TIER that is appropriate for EKPC. The DSC, ROR and ROI are correspondingly lower than what they would otherwise be if the $70,041,960 revenue deficiency were used to calculate these financial measurements.

Q. Based on your experience in developing rates for other G&T cooperatives, are these financial performance measurements that result from applying the proposed rates reasonable?

A. Yes. They are in line with what the G&T cooperatives I have worked with are using to develop rates. It should be noted, however, that none of the G&T cooperatives for which I have developed base rates are subject to regulation by a public service commission. More important, the proposed TIER will allow EKPC to gradually rebuild its equity over time; however, it is important to realize that even with the new rates which are designed to produce a TIER of 1.43, EKPC's equity as a percentage of total capitalization is projected to only be 9.67 percent in December 2011, which is still inadequate. (See Tab 30, page 10 of the filing requirements set forth in the Application.) One of the main reasons that its equity position will not improve more than this is because EKPC will continue to add assets to the balance sheet in support of its effort to install sufficient generation facilities (e.g., Smith Unit 1) to meet the needs of its members.

IV. CLASS COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for EKPC's electric operations based on financial and operating results for the fully forecasted test period?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study. The cost of service study corresponds to the pro-forma financial exhibits included in Seelye Exhibit 2. The objective in performing the electric cost of service study is to determine the rate of return on rate base that EKPC is earning from each rate class, which provides an indication as to whether EKPC's service rates reflect the cost of providing service to each rate class.

Q. **Did you develop the model used to perform the cost of service study?**

A. Yes. I developed the spreadsheet model used to perform the cost of service study submitted in this proceeding.

Q. **What procedure was used in performing the cost of service study?**

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were utilized. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to the rate classes.

Q. **Is this a standard approach used in the electric utility industry?**

A. Yes.

Q. **What functional groups were used in the cost of service study?**

A. The following functional groups were identified in the cost of service study: (1) Production, (2) Production Steam – Direct, (3) Transmission, (3) Distribution Substation, and (4) Distribution Meters. Production Steam – Direct corresponds to production costs that are specifically assigned to provide steam service to a industrial customer.

Q. **How were costs classified as energy related, demand related or customer related?**

A. Classification provides a method of identifying the appropriate cost driver for each functionally assigned cost so that the service characteristics that give rise to the cost can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. Production plant and the cost of transmission lines are examples of costs typically classified as demand costs. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. Distribution meters are the only costs classified as customer-related in the cost of service study.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the electric cost of service study?

A. Yes. Seelye Exhibit 6 shows the results of the first two steps of the cost of service study – functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, EKPC's test-year costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 6, EKPC's accounting costs are functionally assigned and classified using the explicitly determined functional vectors identified in the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28. Internally generated functional vectors are utilized throughout the study to functionally assign costs either on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 27 and 28 of Seelye Exhibit 6. An example of this process is the use of total operation and maintenance expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign and classify these costs on the same basis. (See Seelye Exhibit 6, pages 3 and 4 for the functional assignment of cash working capital on the basis of OMLPP shown on pages 13 and 14.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors".

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 7. The costs shown in the column labeled "Total System" in Seelye

Exhibit 6 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 7. The column labeled "Ref" in Seelye Exhibit 7 provides a reference to the results included in Seelye Exhibit 6.

Q. Please describe the allocation factors used in the electric cost of service study.

A. The following allocation factors were used in the electric cost of service study:

- **PENG** – Production energy-related costs are allocated to the rate classes on the basis of the amount of energy (kWh) delivered to each rate class.
- **6CP** – Production demand-related costs are allocated on the basis of the sum of the class coincident peak demands during the six peak months of June, July, August, December, January, and February.
- **STMD** – The fixed production costs directly assigned in the functional assignment section of the cost of service study are allocated to the industrial customer that receives steam service from EKPC.
- **12CP** – Transmission demand-related costs are allocated on the basis of the sum of the 12 monthly class coincident peak demands during the test year.
- **SUBA** – Distribution substations are allocated to the rate class on the basis of cost weighted number of substations for each rate class by substation capacity category.

- **CUST05** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.

Q. How was the cost of providing interruptible service addressed in the cost of service study?

A. Customers taking service under the interruptible service rider are assigned a demand cost credit per kW based on the levelized carrying costs associated with the current cost of a combustion turbine generating unit. The cost credit is calculated in Seelye Exhibit 8. This calculation is based on an installed cost of $550/kW for a combustion turbine and a cost of capital (return) of 7 percent. Subsequent to developing this estimate, it was brought to my attention that this avoided cost credit may be somewhat overstated because the capital cost of financing a new combustion turbine would almost certainly be less than 7 percent. Although the credit shown in Seelye Exhibit 8 may be somewhat overstated, I believe that the avoided cost estimate is within a range that is reasonable, particularly given the volatility in the cost of purchasing new combustion turbines.

Q. Does the cost of service study consider load-following costs that EKPC will likely incur to provide service to non-conforming loads on the system?

A. No. It is my understanding that EKPC is currently having difficulty meeting certain North American Electric Reliability Corporation (NERC) control performance standards as a result of large fluctuations of a non-conforming load in EKPC's control area. EKPC is currently analyzing various options for addressing these load/resource balancing problems. The cost of service study submitted in this proceeding does not consider the load-following costs created by non-conforming loads, which are difficult to quantify. The Midwest Independent System Operator (MISO) and other regional transmission operators are currently developing markets for ancillary services, including markets for the types of regulation services that may possibly be used to follow large non-conforming loads. In the absence of an ancillary service market, EKPC may have to enter into a bilateral agreement to obtain regulation services from an organization that controls large amounts of generation capacity, which could prove to be more costly than services obtained from an ancillary service market. Because it is unclear at this time whether load-following services will be obtained from an ancillary service market, or by entering into a bilateral agreement with a regulation service provider, or in some other manner, EKPC is currently unable to develop a reasonable estimate of the load-following costs associated with serving non-conforming loads.

Q. Please summarize the results of the electric cost of service study.

A. The following table (Table 1) summarizes the rates of return for each customer class before and after reflecting the Phase 1 rate adjustments proposed by EKPC. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed earlier in my testimony regarding the determination of EKPC's revenue requirements. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Electric Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return Phase I Rates**
Rate E	3.20%	6.12%
Rate B	2.53%	6.63%
Rate C	2.33%	6.02%
Rate G	0.50%	4.43%
Large Special Contract	2.86%	5.72%
Special Contract – Pumping Stations	29.52%	29.52%
Steam Service	4.74%	10.66%
Total System	3.17%	6.19%

Determination of the actual adjusted and proposed rates of return are detailed in Seelye Exhibit 7, pages 21-22 and pages 23-24, respectively.

V. RATE DESIGN

Q. Please describe how EKPC proposes to transition to a cost-based rate structure.

A. The unit charge components of EKPC's current rates do not accurately reflect the cost of providing service. From a cost of service perspective, too large of a portion of EKPC's fixed costs are recovered through the energy charge component of its rates. This is particularly true of EKPC's Rate E. The cost of service study indicates that a large portion of its fixed costs that are currently recovered through the energy charge should instead be recovered through the demand charge component of EKPC's rates. Rather than moving to a fully cost-based rate design in a single step, EKPC is proposing to move to a cost-based rate design in two phases. Under its rate design proposal in this proceeding, EKPC's is proposing that its Phase I rates would go into effect upon approval by the Commission, which presumably will be at the end of the 6-month suspension period, and would remain in effect for 12 months, at which time Phase II rates would go into effect and remain in effect as EKPC's on-going rates until superseded by a subsequent rate order. The Phase I rates are designed to serve as a *temporary* or *transitional* rate design until cost-based rates can be implemented in Phase II. A phased-in approach was developed because of concerns expressed by EKPC's member systems about implementing cost-based rates in a short period of time. Although there was a general recognition on the part of the member systems that EKPC's rates should reflect the cost of providing service, a number of member systems expressed a desire to transition to a cost-based rate structure in a more gradual, two-phased manner. This phase-in of cost-based rates would provide the member systems with more time to develop retail rates that reflect wholesale costs and to educate retail customers about how to take advantage of cost-based rate offerings.

Q. Is EKPC's phased-in approach consistent with the ratemaking principle of "gradualism"?

A. Yes.

Q. How were the Phase I rates developed?

A. EKPC's Phase I rates were developed by allocating the proposed revenue increase to each rate component of each rate schedule and special contract on a pro-rata basis, with the exception of the special contract for the pumping stations. In other words, in Phase I

EKPC is proposing to increase each rate component of each rate schedule by the same percentage.

Q. Have you prepared an exhibit detailing the revenue impact of the Phase I rates?

A. Yes. The revenue impact of EKPC's Phase I rates is detailed in Seelye Exhibit 9. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. How were the Phase II rate developed?

A. The Phase II rates were developed based on the results of the cost of service study. Specifically, the individual charges within each rate schedule were based on the unit costs determined from the cost of service study. Consequently, the demand charges, substation charges, and meter-point charges included in the Phase II rates are higher than those included in the Phase I rates. However, the energy charges in the Phase II rates are lower than those included in the Phase I rates.

Q. What is the proposed metering point charge for the Phase II rates?

A. For the Phase II rates, EKPC is proposing to increase the metering point charge from the current level of $125 per month to $230 per month. The $230 charge is supported by the cost of service study.

Q. Please describe the changes to the substation charges in the Phase II rates?

A. EKPC currently has substation categories: (i) 1,000 to 2,999 kVa, (ii) 3,000 to 7,499 kVa, (iii) 7,500 to 14,999 kVa, and (iv) greater than 15,000 kVa. For the Phase II rates, EKPC proposes to incorporate the following six substation categories: (i) 1,000 to 4,999 kVa, (ii) 5,000 to 9,999 kVa, (iii) 10,000 to 14,999 kVa substation, (iv) 15,000 to 29,999 kVa, (v) 30,000 to 50,999, and (iv) greater than 51,000 kVa. These six categories more accurately represent the capacity and cost relationships of the various types of substations that EKPC installs. The proposed unit costs reflect the carrying costs of six categories of substations based on average embedded installed costs.

Q. There are two rate alternatives available to members under EKPC's current Rate E. In the proposed Phase II, rates would this optional rate structure be available.

A. No. In the Phase II rates, the two rate options for Rate E would be eliminated, and the rate schedule would reflect cost-based demand and energy charges.

Q. Would the interruptible credit be modified under the Phase II rates?

A. The interruptible credit is updated for both the Phase I and Phase II rates. For the Phase I rates, the interruptible credit is increased by the same percentage as all other rate components. For the Phase II rates, the interruptible credit is increased to reflect the carrying costs associated with the current cost of installing a combustion turbine, as described earlier in my testimony.

Q. Are the proposed Phase II rates designed to produce the same overall revenue as the Phase I rates?

A. Yes. Although both Phase I and Phase II rates are designed to produce approximately the same overall revenues based on test-year billing determinants, the proposed Phase II rates include unit charges that more accurately track the results of the cost of service study. The two sets of rates result in slightly different overall revenues because of rounding.

Q. **Have you prepared an exhibit detailing the revenue impact of the Phase II rates?**

A. Yes. The revenue impact of EKPC's Phase II rates is detailed in Seelye Exhibit 10. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. **Does this conclude your testimony?**

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	)	**CASE NO. 2008-00409**

<u>AFFIDAVIT</u>

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

William Steven Seelye, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

____

Subscribed and sworn before me on this 27th day of October, 2008.

____
Notary Public

My Commission expires: December 8, 2009

Seelye Exhibit 1

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 130 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

<u>Education</u>
Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

<u>Expert Witness Testimony</u>

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Seelye Exhibit 2

EAST KENTUCKY POWER COOPERATIVE, INC.
Calculation of Revenue Requirement
Based on Forecasted Revenues and Expenses
For the 12 Month Period Ended May 31, 2010

Line	Description	Reference		Amount
1	**Total Operating Revenue & Patronage Capital Per Budget**	Eames Exhibit 1, Page 1, Line 8	$	886,273,772
2				
3	Adjustments to Revenue:			
4	To Remove Fuel In Base Rates	Schedule 1.01		(350,719,383)
5	To Remove Fuel Adjustment Clause Revenue	Schedule 1.01		(108,892,230)
6	To Remove Environmental Surcharge Revenue	Eames Exhibit 1, Page 1, Line 3		(104,725,169)
7	To Adjust Off-System Sales Environmental Surcharge Revenue	Schedule 1.02		(1,377,517)
8				
9	**Adjusted Revenue**	Lines 1 through 7	$	320,759,474
10				
11				
12	**Total Cost of Service**	Eames Exhibit 1, Page 2, Line 26	$	898,541,897
13				
14	Adjustments to Cost of Service:			
15	To Remove Fuel Expense Recoverable through the FAC	Schedule 1.01	$	(403,441,802)
16	To Remove Purchased Power Expense Recoverable through the FAC	Schedule 1.03		(51,684,614)
17	To Remove O&M Expenses Recoverable through the Environmental Surcharge	Schedule 1.04		(31,800,030)
18	To Remove Emissions Allowance Expense Recoverable through the Environmental Surcharge	Schedule 1.05		(6,615,208)
19	To Remove Property Taxes and Property Insurance Recoverable through the Environmental Surcharge	Schedule 1.06		(2,098,198)
20	To Remove Depreciation Expenses Recoverable through the Environmental Surcharge	Schedule 1.07		(19,564,992)
21	To Remove Interest Expenses Recoverable through the Environmental Surcharge	Schedule 1.08		(37,031,989)
22	To Remove Promotional Advertising Expense pursuant to Commission Rule KAR 5:016	Schedule 1.09		(658,906)
23	To Remove Certain Directors' Expenses	Schedule 1.10		(93,300)
24	To Remove Donations	Schedule 1.11		(95,485)
25	To Remove Affiliate Expenses	Schedule 1.12		(28,712)
26	To Remove Lobbying Expenses	Schedule 1.13		(85,422)
27	To Remove Touchstone Energy Dues	Schedule 1.14		(414,000)
28	To Remove Other Miscellaneous Expenses	Schedule 1.15		(155,940)
29	To Normalize Ratecase Expenses	Schedule 1.16		100,000
30	Amortize 2004 Force Outage Balance	Schedule 1.17		3,419,058
31	To Normalize Generation Overhaul Expenses	Schedule 1.18		2,300,000
32				
33				
34	**Adjusted Cost of Service**	Lines 12 through 31	$	350,592,357
35				
36	**Adjusted Operating Margins**	Line 9 less Line 34	$	(29,832,883)
37				
38	**Non-Operating Items**			
39	Interest Income	Eames Exhibit 1, Page 2, Line 32	$	4,007,189
40	Other Non-Operating Income	Eames Exhibit 1, Page 2, Line 34		(27,912)
41	Other Capital Credits/Patronage Dividends	Eames Exhibit 1, Page 2, Line 35		250,000
42				
43	**Total Non-Operating Items**	Lines 39 through 41	$	4,229,277
44				
45				
46	**Adjusted Net Margin (Deficit)**	Line 36 plus Line 43	$	(25,603,606)

EAST KENTUCKY POWER COOPERATIVE, INC.
Calculation of Revenue Requirement
Based on Forecasted Revenues and Expenses
For the 12 Month Period Ended May 31, 2010

Line	Description	Reference		Amount
1	**Calculation of Revenue Deficiency**			
2				
3	Adjusted Net Margin (Deficit)	Page 1, Line 46		$ (25,603,606)
4				
5	Interest on Long-Term Debt	Eames Exhibit 1, Page 2, Line 19 Less Line 21, Above	$98,751,898.00	
6				
7	Net Margin Requirement at 1.45 TIER (0.45 x Line 5)			$ 44,438,354
8				
9	Revenue Deficiency (Line 7 - Line 3)			$ 70,041,960

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove FAC Base Rate Revenue

		MWh Sales Subject to FAC	Fuel Cost in Base Rates*	FAC Base Rate Revenue	Member FAC Billings**	Steam FAC Billings	Pumping Station Fuel Cost Billings	Total Fuel Cost Billings
June	2009	1,034,405.00	26.38	27,287,604	4,839,308	94,804	801,201	5,735,313
July	2009	1,170,414.00	26.38	30,875,521	5,695,708	97,842	837,235	6,630,785
August	2009	1,158,883.00	26.38	30,571,334	9,418,926	165,036	691,092	10,275,054
September	2009	1,003,496.00	26.38	26,472,224	7,092,765	142,441	491,972	7,727,178
October	2009	942,223.00	26.38	24,855,843	4,579,464	112,807	431,549	5,123,820
November	2009	1,069,459.00	26.38	28,212,328	4,936,575	100,577	714,603	5,751,755
December	2009	1,301,930.00	26.38	34,344,913	12,775,630	243,670	783,520	13,802,820
January	2010	1,380,682.00	26.38	36,422,391	12,408,150	225,090	916,130	13,549,370
February	2010	1,176,215.00	26.38	31,028,552	12,056,270	235,177	859,292	13,150,739
March	2010	1,147,783.00	26.38	30,278,516	11,385,749	229,815	917,256	12,532,820
April	2010	952,326.00	26.38	25,122,360	6,637,509	152,575	827,377	7,617,461
May	2010	957,081.00	26.38	25,247,797	5,791,586	132,745	870,785	6,795,116
Total		13,294,897.00		350,719,383	97,617,640	1,932,579	9,142,011	108,692,230

* As approved in Case No. 2006-00508, dated July 25, 2007
** Eames Exhibit 1, Page 1, Line 2

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Fuel Costs Recoverable Through the FAC

Total Fuel Costs Excluding Handling -- Eames Exhibit 1, Page 1, Line 3	$412,609,991
Less: Fuel Costs Assigned to Off-System Sales	9,168,189
Fuel Costs Recoverable Through FAC	$403,441,802

Seelye Exhibit 2
Schedule 1.02

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Off-System Sales Environmental Surcharge Revenue

		Off-System Sales Revenue	Monthly Environmental Surcharge Factor	Off-System Sales Environmental Cost
June	2009	1,332,340	13.85%	184,529
July	2009	1,119,946	14.21%	159,144
August	2009	1,159,704	14.22%	164,910
September	2009	1,311,731	13.88%	182,068
October	2009	1,001,815	13.54%	135,646
November	2009	253,615	13.82%	35,050
December	2009	272,436	14.02%	38,196
January	2010	398,354	13.30%	52,981
February	2010	439,280	13.40%	58,864
March	2010	1,096,284	13.54%	148,437
April	2010	866,814	13.46%	116,673
May	2010	734,687	13.75%	101,019
Total		9,987,006		1,377,517

Seelye Exhibit 2
Schedule 1.03

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Purchased Power Expense Recoverable Through the Fuel Adjustment Clause

		Total Purchased Power	Purchased Power Assigned to Forced Outages	Purchased Power Recoverable Through the FAC
June	2009	3,871,392	833,300	3,038,092
July	2009	5,316,797	833,300	4,483,497
August	2009	5,207,600	833,300	4,374,300
September	2009	3,745,707	833,300	2,912,407
October	2009	3,611,051	833,300	2,777,751
November	2009	7,484,043	833,300	6,650,743
December	2009	7,533,457	833,700	6,699,757
January	2010	9,284,117	833,300	8,450,817
February	2010	7,024,925	833,300	6,191,625
March	2010	4,123,190	833,300	3,289,890
April	2010	3,649,035	833,300	2,815,735
May	2010	3,391,056	833,300	2,557,756
Total		$ 64,242,370	$ 10,000,000	$ **51,684,614**

Seelye Exhibit 2
Schedule 1.04

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove O&M Expenses Recoverable Through the Environmental Surcharge

Descr	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	
Ash Storage	$ 553,633	$ 553,633	$ 553,633	$ 553,633	$ 407,573	$ 553,633	$ 553,633	$ 621,047	$ 621,047	$ 621,047	$ 621,047	$ 433,510	$ 6,647,069
Ammonia	325,000	335,000	335,000	304,000	256,000	325,000	333,000	381,654	344,719	381,654	326,426	338,825	$ 3,986,278
Limestone	981,019	1,013,719	1,013,719	829,578	748,707	981,019	1,013,719	1,122,668	1,014,024	1,122,668	1,042,123	822,606	$ 11,705,569
Magnesium	142,000	207,000	208,000	202,000	138,000	202,000	207,000	220,000	199,000	220,000	194,000	220,000	$ 2,359,000
Units 3 and 4 Boiler Controls Maint	110,464	110,435	60,750	60,464	62,346	310,477	63,624	81,110	81,110	121,110	81,110	581,110	$ 1,724,110
Unit 1 Precipitator Maint	500	500	500	500	500	500	500	500	500	500	125,500	500	$ 131,000
Units 3 and 4 BagHouse Maint	59,172	59,172	59,172	59,172	59,172	104,172	71,674	50,951	63,867	63,867	63,867	138,867	$ 853,125
Unit 1 SCR Maint	9,833	9,833	9,833	9,833	9,833	9,833	14,003	4,250	7,375	7,375	27,375	7,375	$ 126,751
Unit 2 SCR Maint	9,833	9,833	9,833	9,833	58,833	9,833	14,003	4,125	7,250	7,250	7,250	7,250	$ 155,126
Unit 1 Scrubber Maint	75,429	75,427	75,451	75,429	75,572	75,430	75,667	29,257	47,091	47,104	47,099	47,091	$ 746,047
Unit 2 Scrubber Maint	85,897	85,896	85,926	85,897	86,083	85,901	123,889	31,695	51,592	51,609	51,617	51,592	$ 877,594
Air Permit Fees	-	-	-	-	-	-	1,410,000	-	-	-	-	-	$ 1,410,000
Stack Monitoring Supplies	19,273	19,273	19,273	19,273	19,273	19,273	28,908	10,036	20,071	20,071	20,071	20,071	$ 234,866
Stack Monitoring Consulting	68,200	68,200	68,200	68,200	68,200	68,200	96,050	38,738	65,472	65,472	65,472	65,472	$ 805,876
Stack Monitoring Maintenance	2,917	2,917	2,917	2,917	2,917	2,917	4,371	1,750	3,499	3,499	3,499	3,499	$ 37,619
Totals by month	$ 2,443,170	$ 2,550,838	$ 2,502,207	$ 2,280,729	$ 1,993,009	$ 2,748,188	$ 4,010,041	$ 2,597,781	$ 2,526,617	$ 2,733,226	$ 2,676,456	$ 2,737,768	$ 31,800,030

Seelye Exhibit 2
Schedule 1.05

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Emissions Allowance Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	800,853
July	2009	982,179
August	2009	958,652
September	2009	722,765
October	2009	511,628
November	2009	768,152
December	2009	838,169
January	2010	230,884
February	2010	199,796
March	2010	185,781
April	2010	117,482
May	2010	298,867
Total		$ 6,615,208

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Property Taxes and Insurance Expenses Recoverable Through the Environmental Surcharge

		Amount
June	2009	177,316
July	2009	176,867
August	2009	176,419
September	2009	175,971
October	2009	175,522
November	2009	175,074
December	2009	174,626
January	2010	174,177
February	2010	173,729
March	2010	173,281
April	2010	172,832
May	2010	172,384
Total		$ 2,098,198

Seelye Exhibit 2
Schedule 1.07

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Depreciation Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	1,630,416
July	2009	1,630,416
August	2009	1,630,416
September	2009	1,630,416
October	2009	1,630,416
November	2009	1,630,416
December	2009	1,630,416
January	2010	1,630,416
February	2010	1,630,416
March	2010	1,630,416
April	2010	1,630,416
May	2010	1,630,416
		$ 19,564,992

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Interest Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	3,140,884
July	2009	3,129,337
August	2009	3,117,876
September	2009	3,107,416
October	2009	3,097,328
November	2009	3,085,754
December	2009	3,075,310
January	2010	3,072,217
February	2010	3,063,967
March	2010	3,055,908
April	2010	3,047,553
May	2010	3,038,439
		$ 37,031,989

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Promotional Advertising

		Amount
June	2009	24,191
July	2009	19,701
August	2009	62,451
September	2009	65,951
October	2009	62,451
November	2009	59,451
December	2009	36,324
January	2010	149,782
February	2010	67,451
March	2010	72,251
April	2010	19,451
May	2010	19,451
		$ 658,906

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Directors' Expenses

		Amount
June	2009	7,775
July	2009	7,775
August	2009	7,775
September	2009	7,775
October	2009	7,775
November	2009	7,775
December	2009	7,775
January	2010	7,775
February	2010	7,775
March	2010	7,775
April	2010	7,775
May	2010	7,775
		$ 93,300

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Directors' Expenses

1	Test-Year Directors' Fees and Expenses	$	312,000
2			
3	Items not Removed from test year		
4			
5	Fees for Regular Board Meetings	$	163,200
6	Chair and Secretary Fees		9,600
7	Committee Chair Fees		7,200
8	Audit Committee Chair Fees		800
9	Two Special Board Meetings		13,600
10	Fees for Training Seminars for Each Board Member for Three Days		15,300
11	Normal Expenses		25,000
12			
13	Total Ordinary Expenses (lines 5 thru 11)	$	234,700
14			
15	Amounts Removed From Directors' Fees and Expenses (line 1 less 13)	$	77,300
16			
17	Monthly Amounts Removed From Directors' Fees and Expenses (line 15 / 12)	$	6,442
18			
19	Monthly Directors' Severence Fees Budgeted Separately	$	1,333
20			
21	Total Monthly Amount Removed from Test-Year Expenses (line 17 + line 19)	$	7,775

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Donations

		Amount
June	2009	8,317
July	2009	8,327
August	2009	7,667
September	2009	7,667
October	2009	7,867
November	2009	7,667
December	2009	11,587
January	2010	5,418
February	2010	7,937
March	2010	7,667
April	2010	7,667
May	2010	7,697
		$ 95,485

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Affiliate Transactions

		ACES Expenses	Propane Expenses	Envision Expenses	Total
June	2009	458	568	1,124	2,150
July	2009	458	567	1,075	2,100
August	2009	458	570	1,075	2,103
September	2009	458	649	1,112	2,219
October	2009	458	585	1,151	2,194
November	2009	458	567	1,091	2,116
December	2009	690	646	1,250	2,586
January	2010	250	565	2,041	2,856
February	2010	500	611	1,359	2,470
March	2010	1,300	612	1,514	3,426
April	2010	500	611	1,111	2,222
May	2010	500	611	1,159	2,270
		$ 6,488	$ 7,162	$ 15,062	**$ 28,712**

Seelye Exhibit 2
Schedule 1.13

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Lobbying Expenses

		Amount
June	2009	$ 29,994
July	2009	4,992
August	2009	5,013
September	2009	4,994
October	2009	5,080
November	2009	4,882
December	2009	5,347
January	2010	4,922
February	2010	4,977
March	2010	5,143
April	2010	4,941
May	2010	5,137
Total		**$ 85,422**

Seelye Exhibit 2
Schedule 1.14

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Touchstone Energy Dues

		Amount
January	2010	**$ 414,000**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Miscellaneous Expenses

	Forecasted Expense June 2009-May 2010
Executive Retirement Plan	$ 45,000
Employee Recognition Dinner	40,000
Employee Food Certificates	26,000
Vending Supplies	25,940
Employee Recreation	19,000
Total	**$ 155,940**

Seelye Exhibit 2
Schedule 1.16

Estimated Rate Case Expenses
Case No. 2008-00409

Rate Case Consultant	$	175,000
TIER and Equity Consultant		25,000
Decoupling Rate Expert		5,000
Rate Design Consultant		5,000
Advertising Member Cooperatives		50,000
Supplies, Expenses, Shipping		40,000
Total	$	300,000
Amortization Period		3 Years
Annual Amortized Amount	$	100,000

Seelye Exhibit 2
Schedule 1.17

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Amortize 2004 Forced Outage Balance

2004 Spurlock 1 Forced Outage Costs-- Allowance for 3-Year Amortization per Order in Case No. 2006-00472, dated December 5, 2007		$ 20,514,346
Monthly Amortization	$ 569,842.94	
Amortization December 2007- May 2009		$ 10,257,173
Unamortized Balance--June 1, 2009		$ 10,257,173
Period for Amortizing Remaining Balance	3 Years	
Annual Amortization		**$ 3,419,058**

East Kentucky Power Cooperative, Inc.
Adjustment to Normalize Generating Unit Turbine/Boiler Overhaul

Unit		Turbine/Boiler Overhaul Costs 2009 Dollars	Scheduled Overhaul Period in Years		Annual Normalization Adjustment
Cooper 1	$	3,100,000	10	$	300,000
Cooper 2		4,400,000	10		400,000
Dale 1		1,500,000	10		200,000
Dale 2		1,500,000	10		200,000
Dale 3		2,500,000	10		300,000
Dale 4		4,000,000	10		400,000
Spurlock 1		8,000,000	10		800,000
Spurlock 2		8,000,000	10		800,000
Spurlock 3		8,000,000	10		800,000
Spurlock 4		8,000,000	10		800,000
Smith CT1		4,000,000	6		700,000
Smith CT2		4,000,000	6		700,000
Smith CT3		4,000,000	6		700,000
Total				$	7,100,000
Less: Overhaul Expenses During Test Year (Cooper 1)					2,100,000
Less: Overhaul Expenses During Test Year (Dale 1&2)					2,700,000
Annual Normalization Adjustment for Turbine/Boiler Overhauls				$	**2,300,000**

Seelye Exhibit 3

EAST KENTUCKY POWER COOPERATIVE, INC.
Forecasted Test Period 13-Month Average Net Cost Rate Base

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Net Cost Rate Base -- Including Environmental														
Utility Plant in Service														
Generation	2,551,870,180	2,563,656,180	2,575,442,180	2,587,228,180	2,599,014,180	2,610,800,180	2,622,586,180	2,634,372,180	2,639,663,180	2,644,954,180	2,650,245,180	2,655,536,180	2,660,827,180	2,615,091,949
Transmission	459,617,373	464,793,173	469,968,973	475,144,773	480,320,573	485,496,373	490,672,173	495,847,973	497,393,573	498,939,173	500,484,773	502,030,373	503,575,973	486,483,481
Distribution	166,725,511	168,943,711	171,161,911	173,380,111	175,598,311	177,816,511	180,034,711	182,252,911	182,915,311	183,577,711	184,240,111	184,902,511	185,564,911	178,239,557
General	78,029,799	78,568,799	79,107,799	79,646,799	80,185,799	80,724,799	81,263,799	81,802,799	82,050,799	82,298,799	82,546,799	82,794,799	83,042,799	80,926,030
Total Utility Plant in Service	3,256,242,863	3,275,961,863	3,295,680,863	3,315,399,863	3,335,118,863	3,354,837,863	3,374,556,863	3,394,275,863	3,402,022,863	3,409,769,863	3,417,516,863	3,425,263,863	3,433,010,863	3,360,743,017
Construction Work in Progress (CWIP)														
Generation	189,194,310	191,258,310	193,322,310	195,386,310	197,450,310	199,514,310	201,578,310	203,642,310	226,540,310	249,438,310	272,336,310	295,234,310	318,132,310	225,617,541
Transmission	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134
Distribution	41	41	41	41	41	41	41	41	41	41	41	41	41	41
General	114	114	114	114	114	114	114	114	114	114	114	114	114	114
Total CWIP	190,597,600	192,661,600	194,725,600	196,789,600	198,853,600	200,917,600	202,981,600	205,045,600	227,943,600	250,841,600	273,739,600	296,637,600	319,535,600	227,020,830
Materials & Supplies	48,347,000	50,141,000	51,934,000	53,728,000	55,522,000	57,316,000	59,110,000	60,904,000	61,059,000	61,214,000	61,369,000	61,524,000	61,678,000	57,218,923
Fuel Stock	62,517,000	62,930,000	63,343,000	63,756,000	64,169,000	64,582,000	64,995,000	65,408,000	65,701,000	65,994,000	66,287,000	66,580,000	66,872,000	64,856,462
Cash Working Capital (1/8th of Adj. Annual O&M)	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673
Total	3,584,690,135	3,608,680,135	3,632,669,135	3,656,659,135	3,680,649,135	3,704,639,135	3,728,629,135	3,752,619,135	3,783,712,135	3,814,805,135	3,845,898,135	3,876,991,135	3,908,082,135	3,736,824,904
Less: Accumulated Depreciation														
Generation	585,350,251	589,740,447	594,130,677	598,520,907	603,251,096	608,008,072	612,765,048	617,544,759	622,328,934	627,113,109	631,903,980	636,694,851	641,485,722	612,987,527
Transmission	132,961,962	133,591,648	134,221,334	134,851,020	135,480,706	136,129,210	136,777,714	137,454,202	138,130,693	138,807,184	139,483,675	140,160,166	140,840,135	136,837,665
Distribution	39,576,599	39,913,146	40,249,693	40,586,240	40,922,787	41,259,631	41,596,475	41,944,669	42,292,866	42,641,063	42,989,260	43,337,457	43,692,632	41,615,578
General	49,379,855	49,746,442	50,113,279	50,480,179	50,847,225	51,214,396	51,581,567	52,227,752	52,737,638	53,249,024	53,768,625	54,288,557	54,808,489	51,880,233
Total Accumulated Depreciation	807,268,667	812,991,683	818,714,983	824,438,346	830,501,814	836,611,309	842,720,804	849,171,382	855,490,131	861,810,380	868,145,540	874,481,031	880,826,978	843,321,004
Net Investment Rate Base	2,777,421,468	2,795,688,452	2,813,954,152	2,832,220,789	2,850,147,321	2,868,027,826	2,885,908,331	2,903,447,753	2,928,222,004	2,952,994,755	2,977,752,595	3,002,510,104	3,027,255,157	2,893,503,901

EAST KENTUCKY POWER COOPERATIVE, INC.
Forecasted Test Period 13-Month Average Net Cost Rate Base

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Net Cost Rate Base Items -- Environmental Plant														
Plant in Service	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943
Accumulated Depreciation	53,894,690	55,525,106	57,155,222	58,785,937	60,416,353	62,046,769	63,677,184	65,307,600	66,938,016	68,568,431	70,198,847	71,829,263	73,459,678	63,677,161
Allowance Inventory	8,317,890	7,516,228	6,531,823	5,571,555	4,847,780	4,336,152	3,568,000	2,729,832	3,597,547	3,397,752	3,211,970	3,094,488	2,795,622	4,578,203
Cash Working Capital	2,496,344	2,687,838	2,892,790	3,091,664	3,262,853	3,299,600	3,282,709	3,571,585	3,688,928	3,797,374	3,931,648	3,935,936	3,963,052	3,377,102
Net Cost Rate Base -- Excluding Environmental														
Utility Plant in Service														
Generation	1,851,560,237	1,863,346,237	1,875,132,237	1,886,918,237	1,898,704,237	1,910,490,237	1,922,276,237	1,934,062,237	1,939,353,237	1,944,644,237	1,949,935,237	1,955,226,237	1,960,517,237	1,914,782,006
Transmission	459,617,373	464,793,173	469,968,973	475,144,773	480,320,573	485,496,373	490,672,173	495,847,973	497,393,573	498,939,173	500,484,773	502,030,373	503,575,973	486,483,481
Distribution	166,725,511	168,943,711	171,161,911	173,380,111	175,598,311	177,816,511	180,034,711	182,252,911	182,915,311	183,577,711	184,240,111	184,902,511	185,564,911	178,239,557
General	78,029,799	78,568,799	79,107,799	79,646,799	80,185,799	80,724,799	81,263,799	81,802,799	82,050,799	82,298,799	82,546,799	82,794,799	83,042,799	80,926,030
Total Utility Plant in Service	2,555,932,920	2,575,651,920	2,595,370,920	2,615,089,920	2,634,808,920	2,654,527,920	2,674,246,920	2,693,965,920	2,701,712,920	2,709,459,920	2,717,206,920	2,724,953,920	2,732,700,920	2,680,433,074
Construction Work in Progress (CWIP)														
Generation	189,194,310	191,258,310	193,322,310	195,386,310	197,450,310	199,514,310	201,578,310	203,642,310	226,540,310	249,438,310	272,336,310	295,234,310	318,132,310	225,617,541
Transmission	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134
Distribution	41	41	41	41	41	41	41	41	41	41	41	41	41	41
General	114	114	114	114	114	114	114	114	114	114	114	114	114	114
Total CWIP	190,597,600	192,661,600	194,725,600	196,789,600	198,853,600	200,917,600	202,981,600	205,045,600	227,943,600	250,841,600	273,739,600	296,637,600	319,535,600	227,020,830
Materials & Supplies	48,347,000	50,141,000	51,934,000	53,728,000	55,522,000	57,316,000	59,110,000	60,904,000	61,059,000	61,214,000	61,369,000	61,524,000	61,678,000	57,218,923
Fuel Stock	54,199,110	55,413,772	56,811,177	58,184,445	59,321,220	60,245,848	61,427,000	62,678,168	62,103,453	62,596,248	63,075,030	63,485,512	64,076,378	60,278,259
Cash Working Capital (1/8th of Adj. Annual O&M)	24,489,329	24,297,835	24,092,883	23,894,009	23,722,820	23,686,073	23,702,964	23,414,088	23,296,745	23,188,299	23,054,025	23,049,737	23,022,621	23,608,571
Total	2,873,565,958	2,898,166,126	2,922,934,579	2,947,685,973	2,972,228,559	2,996,693,440	3,021,468,483	3,046,007,775	3,076,115,717	3,107,300,086	3,138,444,574	3,169,650,768	3,201,013,518	3,028,559,657
Less: Accumulated Depreciation														
Generation	531,455,581	534,215,341	536,975,455	539,734,970	542,834,743	545,961,303	549,087,864	552,237,159	555,390,918	558,544,678	561,705,133	564,865,588	568,026,044	549,310,366
Transmission	132,961,962	133,591,648	134,221,334	134,851,020	135,480,706	136,129,210	136,777,714	137,454,202	138,130,693	138,807,184	139,483,675	140,160,166	140,840,135	136,837,665
Distribution	39,576,599	39,913,146	40,249,693	40,586,240	40,922,787	41,259,631	41,596,475	41,944,669	42,292,866	42,641,063	42,989,260	43,337,457	43,692,632	41,615,578
General	49,379,855	49,746,442	50,113,279	50,480,179	50,847,225	51,214,396	51,581,567	52,227,752	52,737,638	53,249,024	53,768,625	54,288,557	54,808,489	51,880,233
Total Accumulated Depreciation	753,373,977	757,466,577	761,559,761	765,652,409	770,085,461	774,564,540	779,043,620	783,863,782	788,552,115	793,241,949	797,946,693	802,651,768	807,367,300	779,643,842
Net Investment Rate Base	2,120,191,981	2,140,699,549	2,161,374,818	2,182,033,564	2,202,143,098	2,222,128,900	2,242,424,863	2,262,143,993	2,287,563,602	2,314,058,117	2,340,497,881	2,366,999,000	2,393,646,218	2,248,915,815

Seelye Exhibit 4

EAST KENTUCKY POWER COOPERATIVE, INC.
13-Month Average Capitalization

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Capitalization														
Members' Equity	186,645,000	189,290,000	192,747,000	203,104,000	208,837,000	205,568,000	202,821,000	214,570,000	227,679,000	237,682,000	247,682,000	247,216,000	246,465,000	216,177,385
Long-Term Debt	2,570,995,000	2,648,125,000	2,666,867,000	2,660,609,000	2,654,351,000	2,678,092,000	2,671,834,000	2,715,576,000	2,708,726,000	2,701,877,000	2,735,027,000	2,778,178,000	2,771,328,000	2,689,352,692
Total	2,757,640,000	2,837,415,000	2,859,614,000	2,863,713,000	2,863,188,000	2,883,660,000	2,874,655,000	2,930,146,000	2,936,405,000	2,939,559,000	2,982,709,000	3,025,394,000	3,017,793,000	2,905,530,077
Capital Structure (Percentage of Total)														
Members' Equity	6.77%	6.67%	6.74%	7.09%	7.29%	7.13%	7.06%	7.32%	7.75%	8.09%	8.30%	8.17%	8.17%	7.44%
Long-Term Debt	93.23%	93.33%	93.26%	92.91%	92.71%	92.87%	92.94%	92.68%	92.25%	91.91%	91.70%	91.83%	91.83%	92.56%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Total Capitalization -- 13-Month Average	$2,905,530,077
Less: Impact on Equity from Rate Increase	(5,219,927)
Less: Environmental Plant	(641,210,985)
	$2,259,099,165

Seelye Exhibit 5

EAST KENTUCKY POWER COOPERATIVE, INC.
Summary of Coverage Ratios and Rates of Return

		***Forecast* Net of Adjustments Before Revenue Increase**		***Forecast* Net of Adjustments After Revenue Increase***
Adjusted Net Margins	$	(25,603,606)	$	42,255,316
Interest		98,751,898		98,751,898
Times Interest Earned (TIER)		**0.74**		**1.43**
Adjusted Net Margins	$	(25,603,606)	$	42,255,316
Interest		98,751,898		98,751,898
Depreciation		53,993,319		53,993,319
Total	$	127,141,611	$	195,000,533
Normalized Principal and Interest (Excluding Environment P&I)	$	156,157,108	$	156,157,108
Debt Service Coverage Ratio (DSC)		**0.81**		**1.25**
Adjusted Net Margins Before Interest		71,322,720.37		139,181,642.37
Net Cost Rate Base		2,248,915,815		2,248,915,815
Rate of Return on Net Cost Rate Base		**3.17%**		**6.19%**
Capitalization		2,259,099,165		2,259,099,165
Rate of Return on Total Capitalization		**3.16%**		**6.16%**

*The Board-approved rate increase is used, which produces a lower TIER than shown in the revenue requirement.

Seelye Exhibit 6

EAST KENTUC... **,WER COOPERATIVE, INC.**
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Plant in Service							
Intangible Plant	INTPLT	PT&D	$ -	-	-	-	-
Production Plant	PPROD	F001	1,914,782,006	1,895,587,544	-	19,194,462	-
Transmission Plant	PTRAN	F002	486,483,481	-	-	-	486,483,481
Distribution Plant	PDIST	F003	178,239,557	2,752,427	-	-	618,605
Total Production & Transmission Plant	PT&D		2,579,505,044	1,898,339,971	-	19,194,462	487,102,086
General Plant	PGP	PT&D	$ 80,928,030	59,557,516	-	602,197	15,282,084
Total Plant in Service	TPIS		$ 2,660,433,074	$ 1,957,897,487	$ -	$ 19,796,659	$ 502,384,170
Construction Work in Progress (CWIP)							
CWIP Production	CWIP1	PPROD	$ 225,617,541	223,355,870	-	2,261,671	-
CWIP Transmission	CWIP2	PTRAN	1,403,134	-	-	-	1,403,134
CWIP Distribution Plant	CWIP3	PDIST	41	1	-	-	0
CWIP General Plant	CWIP4	PT&D	114	84	-	1	22
Total Construction Work in Progress	TCWIP		$ 227,020,830	$ 223,355,954	$ -	$ 2,261,872	$ 1,403,156
Total Utility Plant			$ 2,887,453,904	$ 2,181,253,442	$ -	$ 22,058,331	$ 503,787,326

EAST KENTUC. JWER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Plant in Service				
Intangible Plant	INTPLT	PT&D	-	-
Production Plant	PPROD	F001	-	-
Transmission Plant	PTRAN	F002	-	-
Distribution Plant	PDIST	F003	167,119,502	7,749,023
Total Production & Transmission Plant	PT&D		167,119,502	7,749,023
General Plant	PGP	PT&D	5,243,119	243,114
Total Plant in Service	TPIS		$ 172,362,621	$ 7,992,137
Construction Work in Progress (CWIP)				
CWIP Production	CWIP1	PPROD	-	-
CWIP Transmission	CWIP2	PTRAN	-	-
CWIP Distribution Plant	CWIP3	PDIST	38	2
CWIP General Plant	CWIP4	PT&D	7	0
Total Construction Work in Progress	TCWIP		$ 46	$ 2
Total Utility Plant			$ 172,362,667	$ 7,992,139

EAST KENTUCK JER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Rate Base							
Total Utility Plant	TUP		$ 2,887,453,904	$ 2,181,253,442	$ -	$ 22,058,331	$ 503,787,326
Less: Acummulated Provision for Depreciation							
Production	ADEPREPA	PPROD	$ 549,310,366	543,803,882	-	5,506,484	-
Transmission	ADEPRTP	PTRAN	136,837,665	-	-	-	136,837,665
Distribution	ADEPRD11	PDIST	41,615,578	642,640	-	-	144,433
General & Common Plant	ADEPRD12	PT&D	51,880,233	38,180,317	-	386,048	9,796,829
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	-	-	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	-	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 779,643,842	$ 582,626,838	$ -	$ 5,892,532	$ 146,778,927
Net Utility Plant	NTPLANT		$ 2,107,810,062	$ 1,598,626,603	$ -	$ 16,165,799	$ 357,008,399
Working Capital							
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 23,608,571	12,519,953	6,071,375	4,348	4,676,152
Materials and Supplies	M&S	TPIS	57,218,923	42,109,229	-	425,774	10,804,963
Fuel Stock	PREPAY	TPIS	60,278,259	44,360,692	-	448,539	11,382,674
Total Working Capital	TWC		$ 141,105,753	$ 98,989,874	$ 6,071,375	$ 878,662	$ 26,863,789
Net Rate Base	RB		$ 2,248,915,815	$ 1,697,616,477	$ 6,071,375	$ 17,044,460	$ 383,872,188

EAST KENTUC JWER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Rate Base						
Total Utility Plant	TUP		$	172,362,667	$	7,992,139
Less: Acummulated Provision for Depreciation						
Production	ADEPREPA	PPROD		-		-
Transmission	ADEPRTP	PTRAN		-		-
Distribution	ADEPRD11	PDIST		39,019,255		1,809,251
General & Common Plant	ADEPRD12	PT&D		3,361,187		155,852
Intangible, Misc, and Other Plant	ADEPRGP	PT&D		-		-
Retirement Work In Progress	ADEPRRT	PT&D		-		-
Total Accumulated Depreciation	TADEPR		$	42,380,442	$	1,965,103
Net Utility Plant	NTPLANT		$	129,982,225	$	6,027,036
Working Capital						
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP		321,820		14,922
Materials and Supplies	M&S	TPIS		3,707,067		171,890
Fuel Stock	PREPAY	TPIS		3,905,273		181,080
Total Working Capital	TWC		$	7,934,161	$	367,892
Net Rate Base	RB		$	137,916,386	$	6,394,928

EAST KENTUC. ,WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$ 7,885,308	7,885,308	-	-	-
501 FUEL	OM501	Energy	$ 386,058,927	-	386,058,927	-	-
502 STEAM EXPENSES	OM502	PROFIX	$ 11,355,691	11,355,691	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	$ 5,274,586	5,274,586	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$ 33,482,685	33,482,685	-	-	-
507 RENTS	OM507	PROFIX	$ -	-	-	-	-
509 ALLOWANCES	OM509	Energy	$ 6,620,870	-	6,620,870	-	-
Total Steam Power Operation Expenses			$ 450,678,067	$ 57,998,270	$ 392,679,797	$ -	$ -
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$ 2,604,989	-	2,604,989	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$ 3,713,719	3,713,719	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$ 28,840,241	-	28,840,241	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$ 9,015,056	-	9,015,056	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$ 117,139	117,139	-	-	-
Total Steam Power Generation Maintenance Expense			$ 44,291,144	$ 3,830,858	$ 40,460,286	$ -	$ -
Total Steam Power Generation Expense			$ 494,969,211	$ 61,829,128	$ 433,140,083	$ -	$ -

EAST KENTUCK   WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Operation and Maintenance Expenses				
Steam Power Generation Operation Expenses				
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	-	-
501 FUEL	OM501	Energy	-	-
502 STEAM EXPENSES	OM502	PROFIX	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-
507 RENTS	OM507	PROFIX	-	-
509 ALLOWANCES	OM509	Energy	-	-
Total Steam Power Operation Expenses			$ -	$ -
Steam Power Generation Maintenance Expenses				
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -
Total Steam Power Generation Expense			$ -	$ -

EAST KENTUCK　　WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Generation Operation Expense							
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$ 278,826	278,826	-	-	-
547 FUEL	OM547	Energy	$ 40,878,558	-	40,878,558	-	-
548 GENERATION EXPENSE	OM548	PROFIX	$ 3,513,607	3,513,607	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$ 1,055,967	1,055,967	-	-	-
550 RENTS	OM550	PROFIX	$ -	-	-	-	-
Total Other Power Generation Expenses			$ 45,726,958	$ 4,848,400	$ 40,878,558	$ -	$ -
Other Power Generation Maintenance Expense							
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 170,556	170,556	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$ 186,558	186,558	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$ 3,955,857	3,955,857	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$ 70,216	70,216	-	-	-
Total Other Power Generation Maintenance Expense			$ 4,383,187	$ 4,383,187	$ -	$ -	$ -
Total Other Power Generation Expense			$ 50,110,145	$ 9,231,587	$ 40,878,558	$ -	$ -
Total Station Expense			$ 545,079,356	$ 71,060,715	$ 474,018,641	$ -	$ -

EAST KENTUCK ... WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Operation and Maintenance Expenses (Continued)				
Other Power Generation Operation Expense				
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	-	-
547 FUEL	OM547	Energy	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-
550 RENTS	OM550	PROFIX	-	-
Total Other Power Generation Expenses			$ -	$ -
Other Power Generation Maintenance Expense				
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -
Total Other Power Generation Expense			$ -	$ -
Total Station Expense			$ -	$ -

EAST KENTUC‹ ‚WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Supply Expenses							
555 PURCHASED POWER	OM555	OMPP	$ 64,242,370	-	64,242,370	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	3,993,169	3,993,169	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	8,951,678	8,951,678	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ 77,187,217	$ 12,944,847	$ 64,242,370	$ -	$ -
Total Electric Power Generation Expenses			$ 622,266,573	$ 84,005,562	$ 538,261,011	$ -	$ -
Transmission Expenses							
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 3,904,970	-	-	-	3,904,970
561 LOAD DISPATCHING	OM561	LBTRAN	2,555,050	-	-	-	2,555,050
562 STATION EXPENSES	OM562	PTRAN	2,192,606	-	-	-	2,192,606
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	2,307,161	-	-	-	2,307,161
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	15,632,950	-	-	-	15,632,950
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	945,367	-	-	-	945,367
567 RENTS	OM567	PTRAN	446,300	-	-	-	446,300
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-
569 STRUCTURES	OM569	PTRAN	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	1,920,486	-	-	-	1,920,486
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	2,774,520	-	-	-	2,774,520
572 UNDERGROUND LINES	OM572	PTRAN	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	144,039	-	-	-	144,039
Total Transmission Expenses			$ 32,823,449	$ -	$ -	$ -	$ 32,823,449
Distribution Operation Expense							
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ -	-	-	-	-
581 LOAD DISPATCHING	OM581	PDIST	213,127	3,291	-	-	740
582 STATION EXPENSES	OM582	PDIST	808,499	12,485	-	-	2,806
583 OVERHEAD LINE EXPENSES	OM583	PDIST	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	PDIST	-	-	-	-	-
586 METER EXPENSES	OM586	PDIST	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-	-	-
588 MISC DISTR EXP – MAPPIN	OM588x	PDIST	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 1,021,626	$ 15,776	$ -	$ -	$ 3,546

EAST KENTUCK   VER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Operation and Maintenance Expenses (Continued)				
Other Power Supply Expenses				
555 PURCHASED POWER	OM555	OMPP	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -
Transmission Expenses				
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-
562 STATION EXPENSES	OM562	PTRAN	-	-
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-
567 RENTS	OM567	PTRAN	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-
569 STRUCTURES	OM569	PTRAN	-	-
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	-	-
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	-	-
572 UNDERGROUND LINES	OM572	PTRAN	-	-
573 MISC PLANT	OM573	PTRAN	-	-
Total Transmission Expenses			$ -	$ -
Distribution Operation Expense				
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-
581 LOAD DISPATCHING	OM581	PDIST	199,830	9,266
582 STATION EXPENSES	OM582	PDIST	758,058	35,150
583 OVERHEAD LINE EXPENSES	OM583	PDIST	-	-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	-	-
585 STREET LIGHTING EXPENSE	OM585	PDIST	-	-
586 METER EXPENSES	OM586	PDIST	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-
589 RENTS	OM589	PDIST	-	-
Total Distribution Operation Expense	OMDO		$ 957,889	$ 44,416

EAST KENTUC ... WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Distribution Maintenance Expense							
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ -	-	-	-	-
591 STRUCTURES	OM591	PDIST	$ -	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	987,836	15,254	-	-	3,428
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	PDIST	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 987,836	$ 15,254	$ -	$ -	$ 3,428
Total Distribution Operation and Maintenance Expenses			2,009,462	31,031	-	-	6,974
Transmission and Distribution Expenses			34,832,911	31,031	-	-	32,830,423
Production, Transmission and Distribution Expenses	OMSUB		$ 657,099,484	$ 84,036,593	$ 538,261,011	$ -	$ 32,830,423
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	OM907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	1,742,340	1,316,206	-	13,310	303,994
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	500	378	-	4	87
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	21,750	16,430	-	166	3,795
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	TUP	10,000	7,554	-	76	1,745
915 MDSE-JOBBING-CONTRACT	OM915	TUP	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 1,774,590	$ 1,340,569	$ -	$ 13,557	$ 309,621
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		658,874,074	85,377,161	538,261,011	13,557	33,140,044

EAST KENTUC… …WER COOPERATIVE, INC.
Cost of Service Study
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12 Months Ended
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Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Operation and Maintenance Expenses (Continued)						
Distribution Maintenance Expense						
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM		-		-
591 STRUCTURES	OM591	PDIST		-		-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST		926,207		42,946
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST		-		-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST		-		-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST		-		-
597 MAINTENANCE OF METERS	OM597	PDIST		-		-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST		-		-
Total Distribution Maintenance Expense	OMDM		$	926,207	$	42,946
Total Distribution Operation and Maintenance Expenses				1,884,095		87,362
Transmission and Distribution Expenses				1,884,095		87,362
Production, Transmission and Distribution Expenses	OMSUB		$	1,884,095	$	87,362
Customer Accounts Expense						
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025		-		-
902 METER READING EXPENSES	OM902	F025		-		-
903 RECORDS AND COLLECTION	OM903	F025		-		-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025		-		-
905 MISC CUST ACCOUNTS	OM903	F025		-		-
Total Customer Accounts Expense	OMCA		$	-	$	-
Customer Service Expense						
907 SUPERVISION	OM907	TUP		-		-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP		104,007		4,823
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP		-		-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP		30		1
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP		1,298		60
911 DEMONSTRATION AND SELLING EXP	OM911	TUP		-		-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP		-		-
913 ADVERTISING EXPENSES	OM913	TUP		597		28
915 MDSE-JOBBING-CONTRACT	OM915	TUP		-		-
916 MISC SALES EXPENSE	OM916	TUP		-		-
Total Customer Service Expense	OMCS		$	105,932	$	4,912
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2			1,990,027		92,274

EAST KENTUCK. .VER COOPERATIVE, INC.
Cost of Service Study
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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$ 11,309,693	5,778,671	3,620,520	1,123	1,708,572
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	5,606,260	2,864,510	1,794,708	557	846,946
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	-	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	2,046,640	1,045,728	655,181	203	309,189
924 PROPERTY INSURANCE	OM924	TUP	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	905,423	462,625	289,849	90	136,784
926 EMPLOYEE BENEFITS	OM926	LBSUB9	787,580	402,413	252,124	78	118,981
927 FRANCHISE REQUIREMENTS	OM927	TUP	-	-	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	1,238,124	935,309	-	9,458	216,021
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	(478,800)	(244,642)	(153,276)	(48)	(72,333)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	5,260,409	2,687,798	1,683,991	522	794,698
931 RENTS AND LEASES	OM931	PGP	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	1,245,791	916,817	-	9,270	235,250
Total Administrative and General Expense	OMAG		$ 27,921,120	$ 14,849,230	$ 8,143,096	$ 21,254	$ 4,294,106
Total Operation and Maintenance Expenses	TOM		$ 686,795,194	$ 100,226,391	$ 546,404,107	$ 34,811	$ 37,434,150
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$ 188,994,469	$ 100,226,391	$ 48,603,382	$ 34,811	$ 37,434,150

EAST KENTUC.   ,WER COOPERATIVE, INC.
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Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Operation and Maintenance Expenses (Continued)				
Administrative and General Expense				
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	191,909	8,898
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	95,130	4,411
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	34,728	1,610
924 PROPERTY INSURANCE	OM924	TUP	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	15,364	712
926 EMPLOYEE BENEFITS	OM926	LBSUB9	13,364	620
927 FRANCHISE REQUIREMENTS	OM927	TUP	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	73,908	3,427
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	(8,125)	(377)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	89,261	4,139
931 RENTS AND LEASES	OM931	PGP	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	80,712	3,742
Total Administrative and General Expense	OMAG		$ 586,252	$ 27,183
Total Operation and Maintenance Expenses	TOM		$ 2,576,279	$ 119,457
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$ 2,576,279	$ 119,457

EAST KENTUCI ЛER COOPERATIVE, INC.
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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$ 2,252,669	2,252,669	-	-	-
501 FUEL	LB501	Energy	$ 1,477,744	-	1,477,744	-	-
502 STEAM EXPENSES	LB502	PROFIX	$ 1,770,487	1,770,487	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	$ 1,368,779	1,368,779	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$ 958,705	958,705	-	-	-
507 RENTS	LB507	PROFIX	$ -	-	-	-	-
509 ALLOWANCES	LB509	Energy	$ -	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 7,828,384	$ 6,350,640	$ 1,477,744	$ -	$ -
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$ 729,965	-	729,965	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$ 306,869	306,869	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$ 2,668,789	-	2,668,789	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$ 645,029	-	645,029	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$ 15,125	15,125	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 4,365,777	$ 321,994	$ 4,043,783	$ -	$ -
Total Steam Power Generation Expense			$ 12,194,161	$ 6,672,634	$ 5,521,527	$ -	$ -

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Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Labor Expenses				
Steam Power Generation Operation Expenses				
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	-	-
501 FUEL	LB501	Energy	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-
507 RENTS	LB507	PROFIX	-	-
509 ALLOWANCES	LB509	Energy	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -
Steam Power Generation Maintenance Expenses				
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -
Total Steam Power Generation Expense			$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Other Power Generation Operation Expense							
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 79,755	79,755	-	-	-
547 FUEL	LB547	Energy	$ 7,355	-	7,355	-	-
548 GENERATION EXPENSE	LB548	PROFIX	$ 327,970	327,970	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$ 34,616	34,616	-	-	-
550 RENTS	LB550	PROFIX	$ -	-	-	-	-
Total Other Power Generation Expenses	LBSUB7		$ 449,696	$ 442,341	$ 7,355	$ -	$ -
Other Power Generation Maintenance Expense							
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ 47,915	47,915	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$ 1,695	1,695	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$ 145,449	145,449	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$ 5,195	5,195	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB8		$ 200,254	$ 200,254	$ -	$ -	$ -
Total Other Power Generation Expense			$ 649,950	$ 642,595	$ 7,355	$ -	$ -
Total Production Expense	LPREX		$ 12,844,111	$ 7,315,229	$ 5,528,882	$ -	$ -

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Cost of Service Study
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12 Months Ended
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Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Labor Expenses (Continued)				
Other Power Generation Operation Expense				
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-
547 FUEL	LB547	Energy	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-
550 RENTS	LB550	PROFIX	-	-
Total Other Power Generation Expenses	LBSUB7		$ -	$ -
Other Power Generation Maintenance Expense				
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-
Total Other Power Generation Maintenance Expense	LBSUB8		$ -	$ -
Total Other Power Generation Expense			$ -	$ -
Total Production Expense	LPREX		$ -	$ -

EAST KENTUCKY ER COOPERATIVE, INC.
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12 Months Ended
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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Purchased Power							
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$ -	-	-	-	-
555 BROKERAGE FEES	LBB555	OMPP	$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ 969,165	969,165	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	366,045	366,045	-	-	-
558 DUPLICATE CHARGES	LB558	Energy	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ 1,335,210	$ 1,335,210	$ -	$ -	$ -
Transmission Labor Expenses							
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 844,080	-	-	-	844,080
561 LOAD DISPATCHING	LB561	PTRAN	511,215	-	-	-	511,215
562 STATION EXPENSES	LB562	PTRAN	225,550	-	-	-	225,550
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	264,500	-	-	-	264,500
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	275,005	-	-	-	275,005
567 RENTS	LB567	PTRAN	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	255,005	-	-	-	255,005
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	193,605	-	-	-	193,605
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 2,568,960	$ -	$ -	$ -	$ 2,568,960
Distribution Operation Labor Expense							
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ -	-	-	-	-
581 LOAD DISPATCHING	LB581	PDIST	21,440	331	-	-	74
582 STATION EXPENSES	LB582	PDIST	136,630	2,110	-	-	474
583 OVERHEAD LINE EXPENSES	LB583	PDIST	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	PDIST	-	-	-	-	-
586 METER EXPENSES	LB586	PDIST	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 158,070	$ 2,441	$ -	$ -	$ 549

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Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Labor Expenses (Continued)				
Purchased Power				
555 PURCHASED POWER	LB555	OMPP	-	-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	-	-
555 BROKERAGE FEES	LBB555	OMPP	-	-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-
558 DUPLICATE CHARGES	LB558	Energy	-	-
Total Purchased Power Labor	LBPP		$ -	$ -
Transmission Labor Expenses				
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-
567 RENTS	LB567	PTRAN	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -
Distribution Operation Labor Expense				
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-
581 LOAD DISPATCHING	LB581	PDIST	20,102	932
582 STATION EXPENSES	LB582	PDIST	128,106	5,940
583 OVERHEAD LINE EXPENSES	LB583	PDIST	-	-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	-	-
585 STREET LIGHTING EXPENSE	LB585	PDIST	-	-
586 METER EXPENSES	LB586	PDIST	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-
589 RENTS	LB589	PDIST	-	-
Total Distribution Operation Labor Expense	LBDO		$ 148,208	$ 6,872

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Distribution Maintenance Labor Expense							
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	140,205	2,165	-	-	487
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	PDIST	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 140,205	$ 2,165	$ -	$ -	$ 487
Total Distribution Operation and Maintenance Labor Expenses		PDIST	298,275	4,606	-	-	1,035
Transmission and Distribution Labor Expenses			2,867,235	4,606	-	-	2,569,995
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 17,046,556	$ 8,655,045	$ 5,528,882	$ -	$ 2,569,995
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ -	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -
Customer Service Expense							
907 SUPERVISION	LB907	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	224,432	169,541	-	1,715	39,158
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	TUP	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 224,432	$ 169,541	$ -	$ 1,715	$ 39,158
Sub-Total Labor Exp	LBSUB9		17,270,988	8,824,586	5,528,882	1,715	2,609,153

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Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Labor Expenses (Continued)				
Distribution Maintenance Labor Expense				
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	131,458	6,095
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	-	-
597 MAINTENANCE OF METERS	LB597	PDIST	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 131,458	$ 6,095
Total Distribution Operation and Maintenance Labor Expenses		PDIST	279,666	12,968
Transmission and Distribution Labor Expenses			279,666	12,968
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 279,666	$ 12,968
Customer Accounts Expense				
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-
902 METER READING EXPENSES	LB902	F025	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -
Customer Service Expense				
907 SUPERVISION	LB907	TUP	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	13,397	621
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	-	-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	-	-
916 MISC SALES EXPENSE	LB916	TUP	-	-
Total Customer Service Labor Expense	LBCS		$ 13,397	$ 621
Sub-Total Labor Exp	LBSUB9		293,063	13,589

EAST KENTUCKY . .WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$ 3,220,000	1,645,254	1,030,804	320	486,450
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9		-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	-	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	-	-	-	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB9	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	322,128	164,591	103,121	32	48,664
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	84,265	62,013	-	627	15,912
Total Administrative and General Expense	LBAG		$ 3,626,393	$ 1,871,859	$ 1,133,925	$ 979	$ 551,027
Total Operation and Maintenance Expenses	TLB		$ 20,897,381	$ 10,696,445	$ 6,662,807	$ 2,693	$ 3,160,179
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 20,897,381	$ 10,696,445	$ 6,662,807	$ 2,693	$ 3,160,179

EAST KENTUCK. .VER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Labor Expenses (Continued)				
Administrative and General Expense				
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	54,639	2,533
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB9	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	5,466	253
931 RENTS AND LEASES	LB931	PGP	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	5,459	253
Total Administrative and General Expense	LBAG		$ 65,564	$ 3,040
Total Operation and Maintenance Expenses	TLB		$ 358,627	$ 16,629
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 358,627	$ 16,629

EAST KENTUCKY ,ER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Other Expenses												
Depreciation Expenses												
Production	DEPRDP2	PPROD		56,135,471		55,572,749		-		562,722		-
Transmission	DEPRDP3	PTRAN		-		-		-		-		-
Transmission	DEPRDP4	PTRAN		7,878,173		-		-		-		7,878,173
Distribution	DEPRDP5	PDIST		4,116,033		63,561		-		-		14,285
General & Common Plant	DEPRDP6	PGP		5,428,634		3,995,105		-		40,395		1,025,119
Other Plant	DEPROTH	TPIS		-		-		-		-		-
Total Depreciation Expense	TDEPR		$	73,558,311		59,631,415		-		603,117		8,917,577
Accretion Expense												
Production	ACRTNP	F017	$	-		-		-		-		-
Transmission	ACRTNT	PTRAN	$	-		-		-		-		-
Distribution	ACRTND	PDIST	$	-		-		-		-		-
Total Accretion Expense	TACRTN		$	-	$	-	$	-	$	-	$	-
Property Taxes & Other	PTAX	TUP	$	800		604		-		6		140
Amortization of Investment Tax Credit	OTAX	TUP	$	-		-		-		-		-
Other Expenses	OT	TUP	$	-		-		-		-		-
Interest	INTLTD	TUP	$	135,823,886		102,604,692		-		1,037,609		23,697,816
Other Deductions	DEDUCT	TUP	$	2,363,706		1,785,801		-		18,057		412,407
Total Other Expenses	TOE		$	211,746,703	$	164,022,313	$	-	$	1,658,790	$	33,027,940
Total Cost of Service (O&M + Other Expenses)			$	898,541,897	$	264,248,704	$	546,404,107	$	1,693,600	$	70,462,089

EAST KENTUCK\ ⁄ER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Other Expenses				
Depreciation Expenses				
Production	DEPRDP2	PPROD	-	-
Transmission	DEPRDP3	PTRAN	-	-
Transmission	DEPRDP4	PTRAN	-	-
Distribution	DEPRDP5	PDIST	3,859,241	178,946
General & Common Plant	DEPRDP6	PGP	351,707	16,308
Other Plant	DEPROTH	TPIS	-	-
Total Depreciation Expense	TDEPR		4,210,948	195,254
Accretion Expense				
Production	ACRTNP	F017	-	-
Transmission	ACRTNT	PTRAN	-	-
Distribution	ACRTND	PDIST	-	-
Total Accretion Expense	TACRTN		$ -	$ -
Property Taxes & Other	PTAX	TUP	48	2
Amortization of Investment Tax Credit	OTAX	TUP	-	-
Other Expenses	OT	TUP	-	-
Interest	INTLTD	TUP	8,107,824	375,945
Other Deductions	DEDUCT	TUP	141,098	6,542
Total Other Expenses	TOE		$ 12,459,918	$ 577,743
Total Cost of Service (O&M + Other Expenses)			$ 15,036,197	$ 697,201

EAST KENTUCKY :R COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Functional Vectors							
Production Plant	F001		1,733,178,865	1,715,804,858	0.000000	17,374,007	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.015442	0.000000	0.000000	0.003471
Production Plant	F017		1.000000	0.000000	1.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	0.000000	0.000000	0.500000
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000
Distribution Operation Labor	F023		158,070.00	2,440.96	-	-	548.60
Distribution Maintenance Labor	F024		140,205.00	2,165.09	-	-	486.60
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000
Purchased Power Expenses	OMPP		1.000000	-	1	-	$ -
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors							
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.735932	-	0.007441	0.188835
Total Transmission Plant		PTRAN	1.000000	-	-	-	1.000000
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.530314	0.257168	0.000184	0.198070
Total Plant in Service		TPIS	1.000000	0.735932	-	0.007441	0.188835
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.511856	0.318835	0.000129	0.151224
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.129580	0.816941	0.000021	0.050298
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.811233	0.188767	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.073754	0.926246	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	0.983645	0.016355	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.510949	0.320125	0.000099	0.151071
Total General Plant		PGP	1.000000	0.735932	-	0.007441	0.188835
Total Production Plant		PPROD	1.000000	0.989976	-	0.010024	-
Total Intangible Plant		INTPLT	1.000000	-	-	-	-

EAST KENTUCK\ ˏER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Functional Vectors				
Production Plant	F001		0.000000	0.000000
Transmission Plant	F002		0.000000	0.000000
Distribution Plant	F003		0.937612	0.043475
Production Plant	F017		0.000000	0.000000
Provar	PROVAR		0.000000	0.500000
PROFIX	PROFIX		0.000000	0.000000
Distribution Operation Labor	F023		148,208.29	6,872.14
Distribution Maintenance Labor	F024		131,457.85	6,095.46
Customer Accounts Expense	F025		0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000
Purchased Power Expenses	OMPP		$ -	$ -
Production Energy	Energy		0.000000	0.00%
Internally Generated Functional Vectors				
Total Prod, Trans, and Dist Plant		PT&D	0.064787	0.003004
Total Transmission Plant		PTRAN	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.013632	0.000632
Total Plant in Service		TPIS	0.064787	0.003004
Total Operation and Maintenance Expenses (Labor)		TLB	0.017161	0.000796
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.003020	0.000140
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-
Total Transmission Labor Expenses		LBTRAN	-	-
Sub-Total Labor Exp		LBSUB7	0.016969	0.000787
Total General Plant		PGP	0.064787	0.003004
Total Production Plant		PPROD	-	-
Total Intangible Plant		INTPLT	-	-

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EAST KENTUCK WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Plant in Service							
Power Production Plant							
Production Demand	TPIS	PLPDMD	6CP	$ 1,957,897,487	$ 1,657,339,742	$ 100,395,334	$ 45,383,089
Production Energy	TPIS	PLPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	TPIS	PLPSTM	STMD	$ 19,796,659	$ -	$ -	$ -
Total Power Production Plant		PLPT		$ 1,977,694,146	$ 1,657,339,742	$ 100,395,334	$ 45,383,089
Transmission Plant	TPIS	PLTRN	12CP	$ 502,384,170	$ 411,511,104	$ 27,740,381	$ 12,524,298
Distribution Substation	TPIS	PLDST	SUBA	$ 172,362,621	$ 170,619,193	$ -	$ -
Distribution Meters	TPIS	PLDMC	Cust05	$ 7,992,137	$ 7,966,535	$ -	$ -
Total		PLT		$ 2,660,433,074	$ 2,247,436,574	$ 128,135,715	$ 57,907,387

EAST KENTUCK ˏWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Plant in Service							
Power Production Plant							
Production Demand	TPIS	PLPDMD	6CP	$ 34,154,141	$ 120,625,182	$ -	$ -
Production Energy	TPIS	PLPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	TPIS	PLPSTM	STMD	$ -	$ -	$ -	$ 19,796,659
Total Power Production Plant		PLPT		$ 34,154,141	$ 120,625,182	$ -	$ 19,796,659
Transmission Plant	TPIS	PLTRN	12CP	$ 9,377,821	$ 33,164,092	$ 8,066,474	$ -
Distribution Substation	TPIS	PLDST	SUBA	$ 1,743,428	$ -	$ -	$ -
Distribution Meters	TPIS	PLDMC	Cust05	$ 25,602	$ -	$ -	$ -
Total		PLT		$ 45,300,991	$ 153,789,274	$ 8,066,474	$ 19,796,659

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Net Utility Plant							
Power Production Plant							
Production Demand	NTPLANT	NTPDMD	6CP	$ 1,598,626,603	$ 1,353,220,697	$ 81,972,960	$ 37,055,369
Production Energy	NTPLANT	NTPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$ 16,165,799	$ -	$ -	$ -
Total Power Production Plant		NTPT		$ 1,614,792,402	$ 1,353,220,697	$ 81,972,960	$ 37,055,369
Transmission Plant	NTPLANT	NTTRN	12CP	$ 357,008,399	$ 292,431,429	$ 19,713,099	$ 8,900,121
Distribution Substation	NTPLANT	NTDST	SUBA	$ 129,982,225	$ 128,667,470	$ -	$ -
Distribution Meters	NTPLANT	NTDMC	Cust05	$ 6,027,036	$ 6,007,729	$ -	$ -
Total		NTPLT		$ 2,107,810,062	$ 1,780,327,324	$ 101,686,059	$ 45,955,489

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Net Utility Plant							
Power Production Plant							
Production Demand	NTPLANT	NTPDMD	6CP	$ 27,886,914	$ 98,490,665	$ -	$ -
Production Energy	NTPLANT	NTPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$ -	$ -	$ -	$ 16,165,799
Total Power Production Plant		NTPT		$ 27,886,914	$ 98,490,665	$ -	$ 16,165,799
Transmission Plant	NTPLANT	NTTRN	12CP	$ 6,664,145	$ 23,567,341	$ 5,732,265	$ -
Distribution Substation	NTPLANT	NTDST	SUBA	$ 1,314,755	$ -	$ -	$ -
Distribution Meters	NTPLANT	NTDMC	Cust05	$ 19,307	$ -	$ -	$ -
Total		NTPLT		$ 35,885,120	$ 122,058,006	$ 5,732,265	$ 16,165,799

EAST KENTUC. JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Net Cost Rate Base											
Power Production Plant											
Production Demand	RB	RBPDMD	6CP	$	1,697,616,477	$	1,437,014,589	$	87,048,875	$	39,349,905
Production Energy	RB	RBPENG	PENG	$	6,071,375	$	4,632,980	$	445,944	$	175,434
Production - Steam Direct	RB	RBPSTM	STMD	$	17,044,460	$	-	$	-	$	-
Total Power Production Plant		RBPT		$	1,720,732,313	$	1,441,647,569	$	87,494,819	$	39,525,338
Transmission Plant	RB	RBTRN	12CP	$	383,872,188	$	314,435,998	$	21,196,450	$	9,569,827
Distribution Substation	RB	RBDST	SUBA	$	137,916,386	$	136,521,378	$	-	$	-
Distribution Meters	RB	RBDMC	Cust05	$	6,394,928	$	6,374,443	$	-	$	-
Total		RBPLT		$	2,248,915,815	$	1,898,979,388	$	108,691,268	$	49,095,166

EAST KENTUC. ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Net Cost Rate Base							
Power Production Plant							
Production Demand	RB	RBPDMD	6CP	$ 29,813,722	$ 104,589,386	$ -	$ -
Production Energy	RB	RBPENG	PENG	$ 160,098	$ 434,722	$ 105,352	$ 116,846
Production - Steam Direct	RB	RBPSTM	STMD	$ -	$ -	$ -	$ 17,044,460
Total Power Production Plant		RBPT		$ 29,773,820	$ 105,024,108	$ 105,352	$ 17,161,306
Transmission Plant	RB	RBTRN	12CP	$ 7,165,601	$ 25,340,712	$ 6,163,600	$ -
Distribution Substation	RB	RBDST	SUBA	$ 1,395,008	$ -	$ -	$ -
Distribution Meters	RB	RBDMC	Cust05	$ 20,486	$ -	$ -	$ -
Total		RBPLT		$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306

EAST KENTUC. JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Operation and Maintenance Expenses							
Power Production Plant							
Production Demand	TOM	OMPDMD	6CP	$ 100,226,391	$ 84,840,592	$ 5,139,320	$ 2,323,198
Production Energy	TOM	OMPENG	PENG	$ 546,404,107	$ 416,953,137	$ 40,133,541	$ 15,788,463
Production - Steam Direct	TOM	OMPSTM	STMD	$ 34,811	$ -	$ -	$ -
Total Power Production Plant		OMPT		$ 646,665,308	$ 501,793,729	$ 45,272,861	$ 18,111,661
Transmission Plant	TOM	OMTRN	12CP	$ 37,434,150	$ 30,662,925	$ 2,067,019	$ 933,223
Distribution Substation	TOM	OMDST	SUBA	$ 2,576,279	$ 2,550,220	$ -	$ -
Distribution Meters	TOM	OMDMC	Cust05	$ 119,457	$ 119,075	$ -	$ -
Total		OMPLT		$ 686,795,194	$ 535,125,949	$ 47,339,880	$ 19,044,884

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Operation and Maintenance Expenses											
Power Production Plant											
Production Demand	TOM	OMPDMD	6CP	$	1,748,379	$	6,174,903	$	-	$	-
Production Energy	TOM	OMPENG	PENG	$	14,408,275	$	39,123,577	$	9,481,342	$	10,515,771
Production - Steam Direct	TOM	OMPSTM	STMD	$	-	$	-	$	-	$	34,811
Total Power Production Plant		OMPT		$	16,156,654	$	45,298,480	$	9,481,342	$	10,550,582
Transmission Plant	TOM	OMTRN	12CP	$	698,770	$	2,471,156	$	601,057	$	-
Distribution Substation	TOM	OMDST	SUBA	$	26,059	$	-	$	-	$	-
Distribution Meters	TOM	OMDMC	Cust05	$	383	$	-	$	-	$	-
Total		OMPLT		$	16,881,864	$	47,769,636	$	10,082,399	$	10,550,582

EAST KENTUCI WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Labor Expenses							
Power Production Plant							
Production Demand	TLB	LBPDMD	6CP	$ 10,696,445	$ 9,054,429	$ 548,483	$ 247,938
Production Energy	TLB	LBPENG	PENG	$ 6,662,807	$ 5,084,293	$ 489,385	$ 192,523
Production - Steam Direct	TLB	LBPSTM	STMD	$ 2,693	$ -	$ -	$ -
Total Power Production Plant		LBPT		$ 17,361,945	$ 14,138,721	$ 1,037,868	$ 440,462
Transmission Plant	TLB	LBTRN	12CP	$ 3,160,179	$ 2,588,555	$ 174,497	$ 78,782
Distribution Substation	TLB	LBDST	SUBA	$ 358,627	$ 355,000	$ -	$ -
Distribution Meters	TLB	LBDMC	Cust05	$ 16,629	$ 16,576	$ -	$ -
Total		LBPLT		$ 20,897,381	$ 17,098,852	$ 1,212,365	$ 519,244

EAST KENTUCK /VER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Labor Expenses											
Power Production Plant											
Production Demand	TLB	LBPDMD	6CP	$	186,592	$	659,003	$	-	$	-
Production Energy	TLB	LBPENG	PENG	$	175,693	$	477,070	$	115,615	$	128,228
Production - Steam Direct	TLB	LBPSTM	STMD	$	-	$	-	$	-	$	2,693
Total Power Production Plant		LBPT		$	362,285	$	1,136,073	$	115,615	$	130,922
Transmission Plant	TLB	LBTRN	12CP	$	58,990	$	208,614	$	50,741	$	-
Distribution Substation	TLB	LBDST	SUBA	$	3,627	$	-	$	-	$	-
Distribution Meters	TLB	LBDMC	Cust05	$	53	$	-	$	-	$	-
Total		LBPLT		$	424,956	$	1,344,687	$	166,356	$	130,922

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Depreciation Expenses											
Power Production Plant											
Production Demand	TDEPR	DPPDMD	6CP	$	59,631,415	$	50,477,369	$	3,057,727	$	1,382,226
Production Energy	TDEPR	DPPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	STMD	$	603,117	$	-	$	-	$	-
Total Power Production Plant		DPPT		$	60,234,532	$	50,477,369	$	3,057,727	$	1,382,226
Transmission Plant	TDEPR	DPTRN	12CP	$	8,917,577	$	7,304,533	$	492,406	$	222,313
Distribution Substation	TDEPR	DPDST	SUBA	$	4,210,948	$	4,168,355	$	-	$	-
Distribution Meters	TDEPR	DPDMC	Cust05	$	195,254	$	194,628	$	-	$	-
Total		DPPLT		$	73,558,311	$	62,144,885	$	3,550,133	$	1,604,539

EAST KENTUC ƆWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Depreciation Expenses							
Power Production Plant							
Production Demand	TDEPR	DPPDMD	6CP	$ 1,040,228	$ 3,673,865	$ -	$ -
Production Energy	TDEPR	DPPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	TDEPR	DPPSTM	STMD	$ -	$ -	$ -	$ 603,117
Total Power Production Plant		DPPT		$ 1,040,228	$ 3,673,865	$ -	$ 603,117
Transmission Plant	TDEPR	DPTRN	12CP	$ 166,461	$ 588,680	$ 143,184	$ -
Distribution Substation	TDEPR	DPDST	SUBA	$ 42,593	$ -	$ -	$ -
Distribution Meters	TDEPR	DPDMC	Cust05	$ 625	$ -	$ -	$ -
Total		DPPLT		$ 1,249,908	$ 4,262,544	$ 143,184	$ 603,117

EAST KENTUC.   JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Property and Other Taxes							
Power Production Plant							
Production Demand	PTAX	PRPDMD	6CP	$ 604	$ 512	$ 31	$ 14
Production Energy	PTAX	PRPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	PTAX	PRPSTM	STMD	$ 6	$ -	$ -	$ -
Total Power Production Plant		PRPT		$ 610	$ 512	$ 31	$ 14
Transmission Plant	PTAX	PRTRN	12CP	$ 140	$ 114	$ 8	$ 3
Distribution Substation	PTAX	PRDST	SUBA	$ 48	$ 47	$ -	$ -
Distribution Meters	PTAX	PRDMC	Cust05	$ 2	$ 2	$ -	$ -
Total		PRPLT		$ 800	$ 675	$ 39	$ 17

EAST KENTUC[illegible])WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Property and Other Taxes											
Power Production Plant											
Production Demand	PTAX	PRPDMD	6CP	$	11	$	37	$	-	$	-
Production Energy	PTAX	PRPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	-	$	-	$	-	$	6
Total Power Production Plant		PRPT		$	11	$	37	$	-	$	6
Transmission Plant	PTAX	PRTRN	12CP	$	3	$	9	$	2	$	-
Distribution Substation	PTAX	PRDST	SUBA	$	0	$	-	$	-	$	-
Distribution Meters	PTAX	PRDMC	Cust05	$	0	$	-	$	-	$	-
Total		PRPLT		$	14	$	46	$	2	$	6

EAST KENTUC. ƆWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Interest Expenses							
Power Production Plant							
Production Demand	INTLTD	INPDMD	6CP	$ 102,604,692	$ 86,853,799	$ 5,261,273	$ 2,378,326
Production Energy	INTLTD	INPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	INTLTD	INPSTM	STMD	$ 1,037,609	$ -	$ -	$ -
Total Power Production Plant		INPT		$ 103,642,301	$ 86,853,799	$ 5,261,273	$ 2,378,326
Transmission Plant	INTLTD	INTRN	12CP	$ 23,697,816	$ 19,411,270	$ 1,308,533	$ 590,780
Distribution Substation	INTLTD	INDST	SUBA	$ 8,107,824	$ 8,025,814	$ -	$ -
Distribution Meters	INTLTD	INDMC	Cust05	$ 375,945	$ 374,741	$ -	$ -
Total		INPLT		$ 135,823,886	$ 114,665,623	$ 6,569,806	$ 2,969,106

EAST KENTUC   .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Interest Expenses							
Power Production Plant							
Production Demand	INTLTD	INPDMD	6CP	$ 1,789,866	$ 6,321,429	$ -	$ -
Production Energy	INTLTD	INPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	INTLTD	INPSTM	STMD	$ -	$ -	$ -	$ 1,037,609
Total Power Production Plant		INPT		$ 1,789,866	$ 6,321,429	$ -	$ 1,037,609
Transmission Plant	INTLTD	INTRN	12CP	$ 442,358	$ 1,564,374	$ 380,501	$ -
Distribution Substation	INTLTD	INDST	SUBA	$ 82,010	$ -	$ -	$ -
Distribution Meters	INTLTD	INDMC	Cust05	$ 1,204	$ -	$ -	$ -
Total		INPLT		$ 2,315,439	$ 7,885,802	$ 380,501	$ 1,037,609

EAST KENTUCI .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 873,498,600	$ 698,429,398	$ 57,697,996	$ 23,333,746
Off System Sales Revenue			Energy	$ 9,987,006	$ 7,655,465	$ 736,872	$ 289,884
Wheeling Revenue		LSDPR	RBTRN	$ 2,389,123	$ 1,956,970	$ 131,921	$ 59,560
Other Operating Revenue		OTHREV	RBPLT	$ 399,043	$ 336,951	$ 19,286	$ 8,711
Total Operating Revenues		TOR		$ 886,273,772	$ 708,378,784	$ 58,586,075	$ 23,691,901
Operating Expenses							
Operation and Maintenance Expenses				$ 686,795,194	$ 535,125,949	$ 47,339,880	$ 19,044,884
Depreciation and Amortization Expenses				73,558,311	62,144,885	3,550,133	1,604,539
Property and Other Taxes			NPT	800	675	39	17
Total Operating Expenses		TOE		$ 760,354,305	$ 597,271,510	$ 50,890,052	$ 20,649,441
Utility Operating Margin				$ 125,919,467	$ 111,107,274	$ 7,696,023	$ 3,042,461
Non-Operating Items							
Interest Income			RBPLT	$ 4,007,189	$ 3,383,661	$ 193,670	$ 87,479
Other Non-Operating Income			RBPLT	$ (27,912)	$ (23,569)	$ (1,349)	$ (609)
Other Credits			RBPLT	$ 250,000	$ 211,099	$ 12,083	$ 5,458
Interest on Long Term Debt				$ (135,823,886)	$ (114,665,623)	$ (6,569,806)	$ (2,969,106)
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ (2,363,706)	$ (1,995,908)	$ (114,239)	$ (51,601)
Total Non-Operating Items				$ (133,958,315)	$ (113,090,339)	$ (6,479,642)	$ (2,928,379)
Net Utility Operating Margin		TOM		$ (8,038,848)	$ (1,983,065)	$ 1,216,381	$ 114,082
Net Cost Rate Base				$ 2,248,915,815	$ 1,898,979,388	$ 108,691,268	$ 49,095,166

EAST KENTUCK   /VER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Cost of Service Summary -- Unadjusted											
Operating Revenues											
Sales to Members		REVUC	R01	$	19,703,308	$	49,583,171	$	11,330,994	$	13,439,988
Off System Sales Revenue			Energy	$	264,543	$	718,328	$	128,839	$	193,075
Wheeling Revenue		LSDPR	RBTRN	$	44,597	$	157,714	$	38,361	$	-
Other Operating Revenue		OTHREV	RBPLT	$	6,806	$	23,132	$	1,112	$	3,045
Total Operating Revenues		TOR		$	20,019,253	$	50,462,345	$	11,499,306	$	13,636,108
Operating Expenses											
Operation and Maintenance Expenses				$	16,881,864	$	47,769,636	$	10,082,399	$	10,550,582
Depreciation and Amortization Expenses					1,249,908		4,262,544		143,184		603,117
Property and Other Taxes			NPT		14		46		2		6
Total Operating Expenses		TOE		$	18,131,786	$	52,032,226	$	10,225,585	$	11,153,705
Utility Operating Margin				$	1,887,468	$	(1,569,882)	$	1,273,721	$	2,482,402
Non-Operating Items											
Interest Income			RBPLT	$	68,342	$	232,288	$	11,170	$	30,579
Other Non-Operating Income			RBPLT	$	(476)	$	(1,618)	$	(78)	$	(213)
Other Credits			RBPLT	$	4,264	$	14,492	$	697	$	1,908
Interest on Long Term Debt				$	(2,315,439)	$	(7,885,802)	$	(380,501)	$	(1,037,609)
Other Interest Expense			RBPLT	$	-	$	-	$	-	$	-
Other Deductions			RBPLT	$	(40,313)	$	(137,019)	$	(6,589)	$	(18,037)
Total Non-Operating Items				$	(2,283,622)	$	(7,777,659)	$	(375,301)	$	(1,023,373)
Net Utility Operating Margin		TOM		$	(396,154)	$	(9,347,541)	$	898,420	$	1,459,029
Net Cost Rate Base				$	38,354,915	$	130,364,820	$	6,268,952	$	17,161,306

EAST KENTUCK POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue				$ 886,273,772	$ 708,378,784	$ 58,586,075	$ 23,691,901
Pro-Forma Adjustments:							
To Remove Base Fuel Revenue				$ 350,719,383	$ 272,354,902	$ 26,215,336	$ 10,313,066
To Remove FAC Revenue			FACA	108,692,230	77,066,195	7,417,955	2,918,210
To Remove Environmental Surcharge Revenue		ESR		104,725,170	84,331,966	6,966,754	2,817,437
To Adjust Off-System Sales Environmental Sur. Rev.			RBPLT	1,377,517	1,163,172	86,576	30,072
Total Pro-Forma Operating Revenue				$ 320,759,472	$ 273,462,548	$ 17,919,454	$ 7,613,117

EAST KENTUCK   /IER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue				$ 20,019,253	$ 50,462,345	$ 11,499,306	$ 13,636,108
Pro-Forma Adjustments:							
To Remove Base Fuel Revenue				$ 9,411,524	$ 25,555,625	$ -	$ 6,868,930
To Remove FAC Revenue			FACA	2,663,107	7,231,280	9,451,834	1,943,649
To Remove Environmental Surcharge Revenue		ESR		2,379,079	5,984,513	622,608	1,622,813
To Adjust Off-System Sales Environmental Sur. Rev.			RBPLT	23,493	79,852	3,840	10,512
Total Pro-Forma Operating Revenue				$ 5,542,051	$ 11,611,075	$ 1,421,024	$ 3,190,204

EAST KENTUCI ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Cost of Service Summary -- Pro-Forma											
Operating Expenses											
Operation and Maintenance Expenses				$	686,795,194	$	535,125,949	$	47,339,880	$	19,044,884
Depreciation and Amortization Expenses					73,558,311		62,144,885		3,550,133		1,604,539
Property and Other Taxes			NPT		800		675		39		17
Adjustments to Operating Expenses:											
To Remove Fuel Expense Recoverable Through FAC			FACAL	$	(403,441,802)	$	(305,889,756)	$	(29,443,211)	$	(11,582,906)
To Remove Purchased Power Expense Recoverable Through FAC			FACEX		(51,684,614)	$	(39,310,488)	$	(3,783,804)	$	(1,488,542)
To Remove O&M Expenses Recoverable Through Env. Surcharge			6CP		(31,800,030)	$	(26,918,393)	$	(1,630,614)	$	(737,109)
To Remove Emissions Allowance Expense Recoverable Through ESR			Energy		(6,615,208)	$	(5,070,838)	$	(488,090)	$	(192,014)
To Remove Property Tax & Insurance Recoverable Through ESR			6CP		(2,098,198)	$	(1,776,103)	$	(107,590)	$	(48,635)
To Remove Depreciation Expense Recoverable Through ESR			6CP		(19,564,992)	$	(16,561,561)	$	(1,003,236)	$	(453,507)
To Remove Promotional Advertising Expense			LBPLT		(658,906)	$	(539,136)	$	(38,227)	$	(16,372)
To Remove Certain Director's Expenses			LBPLT		(93,300)	$	(76,341)	$	(5,413)	$	(2,318)
To Remove Donations			LBPLT		(95,485)	$	(78,129)	$	(5,540)	$	(2,373)
To Remove Affiliate Expenses			LBPLT		(28,712)	$	(23,493)	$	(1,666)	$	(713)
To Remove Lobbying Expenses			LBPLT		(85,422)	$	(69,895)	$	(4,956)	$	(2,123)
To Remove Touchstone Energy Dues			LBPLT		(414,000)	$	(338,747)	$	(24,018)	$	(10,287)
To Remove Other Misc. Expenses			LBPLT		(155,940)	$	(127,595)	$	(9,047)	$	(3,875)
To Normalize Rate Case Expenses			RBPLT		100,000	$	84,440	$	4,833	$	2,183
To Amortize 2004 Forced Outage Balance			Energy		3,419,058	$	2,820,853	$	252,268	$	99,242
To Normalize Generation Overhaul Expenses			OMPDMD	$	2,300,000	$	1,946,926	$	117,937	$	53,313
To Reflect Avoided Costs of Interruptible Service				$	(8,824,500)						
Reallocation of Avoided Cost Savings			6CP	$	8,824,500	$	7,469,847	$	452,495	$	204,548
Total Expense Adjustments					(510,917,551)		(384,658,408)		(35,717,877)		(14,181,487)
Total Operating Expenses		TOE		$	249,436,754	$	212,613,102	$	15,172,175	$	6,467,953
Utility Operating Margins -- Pro-Forma				$	71,322,718	$	60,849,446	$	2,747,279	$	1,145,163
Non-Operating Items											
Sum of Non-Operating Items				$	(133,958,315)	$	(113,090,339)	$	(6,479,642)	$	(2,928,379)
Adjustment To Remove Interest Exp. Recoverable Through ESR			6CP	$	37,031,989	$	31,347,191	$	1,898,894	$	858,383
Total Non-Operating Items				$	(96,926,326)	$	(81,743,147)	$	(4,580,748)	$	(2,069,996)
Net Utility Operating Margin				$	(25,603,608)	$	(20,893,701)	$	(1,833,469)	$	(924,833)
Net Cost Rate Base				$	2,248,915,815	$	1,898,979,388	$	108,691,268	$	49,095,168
Return on Rate Base -- Utility Operating Margin Divided by Rate Base					3.17%		3.20%		2.53%		2.33%

EAST KENTUC. WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 16,881,864	$ 47,769,636	$ 10,082,399	$ 10,550,582
Depreciation and Amortization Expenses				1,249,908	4,262,544	143,184	603,117
Property and Other Taxes			NPT	14	46	2	6
Adjustments to Operating Expenses:							
To Remove Fuel Expense Recoverable Through FAC			FACAL	$ (10,570,357)	$ (28,702,269)	$ (9,538,606)	$ (7,714,696)
To Remove Purchased Power Expense Recoverable Through FAC			FACEX	$ (1,358,417)	$ (3,688,584)	$ (1,063,348)	$ (991,431)
To Remove O&M Expenses Recoverable Through Env. Surcharge			6CP	$ (554,729)	$ (1,959,186)	$ -	$ -
To Remove Emissions Allowance Expense Recoverable Through ESR			Energy	$ (175,228)	$ (475,807)	$ (85,341)	$ (127,889)
To Remove Property Tax & Insurance Recoverable Through ESR			6CP	$ (36,602)	$ (129,269)	$ -	$ -
To Remove Depreciation Expense Recoverable Through ESR			6CP	$ (341,297)	$ (1,205,390)	$ -	$ -
To Remove Promotional Advertising Expense			LBPLT	$ (13,399)	$ (42,399)	$ (5,245)	$ (4,128)
To Remove Certain Director's Expenses			LBPLT	$ (1,897)	$ (6,004)	$ (743)	$ (585)
To Remove Donations			LBPLT	$ (1,942)	$ (6,144)	$ (760)	$ (598)
To Remove Affiliate Expenses			LBPLT	$ (584)	$ (1,848)	$ (229)	$ (180)
To Remove Lobbying Expenses			LBPLT	$ (1,737)	$ (5,497)	$ (680)	$ (535)
To Remove Touchstone Energy Dues			LBPLT	$ (8,419)	$ (26,640)	$ (3,296)	$ (2,594)
To Remove Other Misc. Expenses			LBPLT	$ (3,171)	$ (10,034)	$ (1,241)	$ (977)
To Normalize Rate Case Expenses			RBPLT	$ 1,705	$ 5,797	$ 279	$ 763
To Amortize 2004 Forced Outage Balance			Energy	$ 90,586	$ 245,920	$ 44,108	$ 86,099
To Normalize Generation Overhaul Expenses			OMPDMD	$ 40,122	$ 141,702	$ -	$ -
To Reflect Avoided Costs of Interruptible Service					$ (8,824,500)		
Reallocation of Avoided Cost Savings			6CP	$ 153,937	$ 543,673	$ -	$ -
Total Expense Adjustments				(12,781,449)	(44,146,479)	(10,655,102)	(8,776,750)
Total Operating Expenses		TOE		$ 5,350,337	$ 7,885,748	$ (429,516)	$ 2,376,955
Utility Operating Margins -- Pro-Forma				$ 191,714	$ 3,725,327	$ 1,850,540	$ 813,249
Non-Operating Items							
Sum of Non-Operating Items				$ (2,283,622)	$ (7,777,659)	$ (375,301)	$ (1,023,373)
Adjustment To Remove Interest Exp. Recoverable Through ESR			6CP	$ 645,997	$ 2,281,524	$ -	$ -
Total Non-Operating Items				$ (1,637,625)	$ (5,496,135)	$ (375,301)	$ (1,023,373)
Net Utility Operating Margin				$ (1,445,911)	$ (1,770,808)	$ 1,475,240	$ (210,124)
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				0.50%	2.86%	29.52%	4.74%

EAST KENTUC.   ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Pro-Forma (Proposed Phase I Increase)							
Operating Revenues							
Total Operating Revenue				$ 320,759,472	$ 273,462,548	$ 17,919,454	$ 7,613,117
Pro-Forma Adjustments: To Reflect Proposed Increase				$ 67,858,922	$ 55,330,720	$ 4,457,951	$ 1,811,240
Total Pro-Forma Operating Revenue				$ 388,618,394	$ 328,793,268	$ 22,377,405	$ 9,424,357
Operating Expenses							
Total Operating Expenses				$ 249,436,754	$ 212,613,102	$ 15,172,175	$ 6,467,953
Utility Operating Margins -- Pro-Formed for Phase I Increase				$ 139,181,640	$ 116,180,166	$ 7,205,230	$ 2,956,403
Net Cost Rate Base				$ 2,248,915,815	$ 1,898,979,388	$ 108,691,268	$ 49,095,166
Rate of Return				6.19%	6.12%	6.63%	6.02%
Cost of Service Summary -- Pro-Forma (Proposed Phase II Increase)							
Operating Revenues							
Total Operating Revenue				$ 320,759,472	$ 273,462,548	$ 17,919,454	$ 7,613,117
Pro-Forma Adjustments: To Reflect Proposed Increase				$ 67,699,051	$ 55,345,926	$ 4,635,408	$ 2,168,710
Total Pro-Forma Operating Revenue				$ 388,458,523	$ 328,808,474	$ 22,554,862	$ 9,781,827
Operating Expenses							
Total Operating Expenses				$ 249,436,754	$ 212,613,102	$ 15,172,175	$ 6,467,953
Utility Operating Margins -- Pro-Formed for Phase II Increase				$ 139,021,769	$ 116,195,372	$ 7,382,687	$ 3,313,873
Net Cost Rate Base				$ 2,248,915,815	$ 1,898,979,388	$ 108,691,268	$ 49,095,166
Rate of Return				6.18%	6.12%	6.79%	6.75%

EAST KENTUC JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Pro-Forma (Proposed Phase I Increase)							
Operating Revenues							
Total Operating Revenue				$ 5,542,051	$ 11,611,075	$ 1,421,024	$ 3,190,204
Pro-Forma Adjustments: To Reflect Proposed Increase				$ 1,506,943	$ 3,736,682	$ -	$ 1,015,386
Total Pro-Forma Operating Revenue				$ 7,048,994	$ 15,347,757	$ 1,421,024	$ 4,205,590
Operating Expenses							
Total Operating Expenses				$ 5,350,337	$ 7,885,748	$ (429,516)	$ 2,376,955
Utility Operating Margins -- Pro-Formed for Phase I Increase				$ 1,698,657	$ 7,462,009	$ 1,850,540	$ 1,828,635
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306
Rate of Return				4.43%	5.72%	29.52%	10.66%
Cost of Service Summary -- Pro-Forma (Proposed Phase II Increase)							
Operating Revenues							
Total Operating Revenue				$ 5,542,051	$ 11,611,075	$ 1,421,024	$ 3,190,204
Pro-Forma Adjustments: To Reflect Proposed Increase				$ 1,858,583	$ 3,017,371	$ -	$ 673,053
Total Pro-Forma Operating Revenue				$ 7,400,634	$ 14,628,446	$ 1,421,024	$ 3,863,257
Operating Expenses							
Total Operating Expenses				$ 5,350,337	$ 7,885,748	$ (429,516)	$ 2,376,955
Utility Operating Margins -- Pro-Formed for Phase II Increase				$ 2,050,297	$ 6,742,698	$ 1,850,540	$ 1,486,302
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306
Rate of Return				5.35%	5.17%	29.52%	8.66%

EAST KENTUC. JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System		Rate E		Rate B		Rate C
Allocation Factors										
Energy Allocation Factors										
Energy Usage by Class		E01	Energy	1.000000		0.766543		0.073783		0.029026
Customer Allocation Factors										
Rev		R01		873,498,603		698,429,400		57,697,996		23,333,746
Energy		Energy		13,468,652,000		10,324,295,000		993,758,000		390,942,617
FAC Revenue Allocator		FACA		109,031,560	$	77,306,791	$	7,441,113	$	2,927,320
Base Fuel Revenue Allocator		BSFL		13,294,897,000		10,324,295,000		993,758,000		390,942,617
Fuel Expense Applicable to FAC Allocator		FACEX		459,411,613		349,421,098		33,633,291		13,231,276
										407,101,213
Customer Allocators										
Customers (Metering Points)		Cust05		3,746		3,734		-		-
Demand Allocators										
Steam - Direct Assignment		STMD		1		-		-		-
Substation Allocator		SUBA		86,668,910		85,792,264		-		-
Production 6 CP Demands		6CP		15,582,000		13,190,000		799,000		361,183
						0.8465		0.0513		0.0232
Production 12 CP Demands		12CP		29,085,000		23,824,000		1,606,000		725,081
						0.8191		0.0552		0.0249

EAST KENTUC\ JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	0.026489	0.071926	0.012901	0.019333
Customer Allocation Factors							
Rev		R01		19,703,308	49,563,171	11,330,994	13,439,988
Energy		Energy		356,767,383	968,750,000	173,755,000	260,384,000
FAC Revenue Allocator		FACA		$ 2,671,421	$ 7,253,856	$ 9,481,342	$ 1,949,717
Base Fuel Revenue Allocator		BSFL		356,767,383	968,750,000	-	260,384,000
Fuel Expense Applicable to FAC Allocator		FACEX		12,074,631	32,786,905	9,451,834	8,812,579
				371,513,435	1,008,790,761	18,933,176	-
Customer Allocators							
Customers (Metering Points)		Cust05		12	-	-	-
Demand Allocators							
Steam - Direct Assignment		STMD		-	-	-	1
Substation Allocator		SUBA		876,646	-	-	-
Production 6 CP Demands		6CP		271,817	960,000	-	-
				0.0174	0.0616	-	-
Production 12 CP Demands		12CP		542,919	1,920,000	467,000	-
				0.0187	0.0660	0.0161	-

EAST KENTUC. JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Production Energy Allocation				-			
Production Energy Residual Allocator		PENGA		13,294,897,000	10,324,295,000	993,758,000	390,942,617
Production Energy Costs				$ 546,404,107			
Member Specific Assignment				$ 9,481,342	-	-	-
Production Energy Residual			PENGA	$ 536,922,765	$ 416,953,137	$ 40,133,541	$ 15,788,463
Production Energy Total		PENGT		$ 546,404,107	$ 416,953,137	$ 40,133,541	$ 15,788,463
Production Energy Total Allocator		PENG	PENGT	1.000000	0.76309	0.07345	0.02890
FAC Expense Residual Allocator		FACALL		449,959,779	349,421,098	33,633,291	13,231,276
FAC Expense Cost				$ (403,441,802)			
Member Specific Assignment				$ (9,538,606)	-	-	-
FAC Expense Residual			FACALL	$ (393,903,196)	$ (305,889,756)	$ (29,443,211)	$ (11,582,906)
FAC Expense Total		FACT		$ (403,441,802)	$ (305,889,756)	$ (29,443,211)	$ (11,582,906)
FAC Expense Allocator		FACAL	FACT	1.000000	0.75820	0.07298	0.02871

EAST KENTUC. OWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Production Energy Allocation							
Production Energy Residual Allocator		PENGA		356,767,383	968,750,000	-	260,384,000
Production Energy Costs							
Member Specific Assignment				$ -	- $	9,481,342	-
Production Energy Residual			PENGA	$ 14,408,275 $	39,123,577 $	- $	10,515,771
Production Energy Total		PENGT		$ 14,408,275 $	39,123,577 $	9,481,342 $	10,515,771
Production Energy Total Allocator		PENG	PENGT	0.02637	0.07160	0.01735	0.01925
FAC Expense Residual Allocator		FACALL		12,074,631	32,786,905	-	8,812,579
FAC Expense Cost							
Member Specific Assignment				$ -	-	(9,538,606)	-
FAC Expense Residual			FACALL	$ (10,570,357) $	(28,702,269) $	- $	(7,714,696)
FAC Expense Total		FACT		$ (10,570,357) $	(28,702,269) $	(9,538,606) $	(7,714,696)
FAC Expense Allocator		FACAL	FACT	0.02620	0.07114	0.02364	0.01912

Seelye Exhibit 8

East Kentucky Power Cooperative, Inc.
Avoided Cost Estimate of Interruptible Power

Estimated Installed Cost of a CT	$ 550 per kW
Estimated Cost of Capital	7.00%
Depreciation	4.00%
ASL for CT	25 Years
Annual Capacity Cost	$47.20 per kW
Annual Fixed O&M Expenses	16.5 per kW
Total Annual Cost	$63.70 per kW
Monthly Cost	$5.30 per kW

Seelye Exhibit 9

Forecasted Period Phase 1
Summary
Rate Impact Test Year Ended May 31, 2010

	Current	Proposed	$ Incr	% Incr
Rate E	698,429,400	753,760,120	55,330,720	7.92%
Rate B	57,697,996	62,155,947	4,457,951	7.73%
Rate C	23,333,746	25,144,986	1,811,240	7.76%
Rate G	19,703,308	21,210,250	1,506,943	7.65%
Large Special Contract	49,563,171	53,299,853	3,736,682	7.54%
Steam Service	13,439,988	14,455,374	1,015,386	7.55%
Pumping Stations	11,330,994	11,330,994	-	0.00%
Total	873,498,604	941,357,525	67,858,922	7.77%

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $	Proposed Billing Units	Proposed Rate	Proposed $
RATE E - 16 Customers							
Metering Point Charge							
All Customers	3,734	$	125.00	466,750	3,734	138.00	515,292
Substation charges							
Substation 1,000 - 2,999 kVa	36	$	944	33,984	36	1,041.00	37,476
Substation 3,000 - 7,499 kVa	504		2,373	1,195,992	504	2,617.00	1,318,968
Substation 7,500 - 14,999 kVa	2,544		2,855	7,263,120	2,544	3,149.00	8,011,056
Substation > 15,000 kVa	578		4,605	2,661,690	578	5,079.00	2,935,662
	3,662			11,154,786			12,303,162
Demand Charge							
Option 1 (Owen)	2,343,000	$	6.92	16,213,560	2,343,000	7.63	17,877,090
Option 2	21,481,000	$	5.22	112,130,820	21,481,000	5.76	123,730,560
	23,824,000			128,344,380			141,607,650
Energy Charge	kWh						
On-Peak (Option 1)	564,787,000	$	0.035406	19,996,849	564,787,000	0.039053	22,056,627
Off-Peak (Option 1)	526,652,000	$	0.034904	18,382,261	526,652,000	0.038499	20,275,575
On-Peak (Option 2)	4,782,184,968	$	0.042470	203,099,396	4,782,184,968	0.046844	224,016,673
Off-Peak (Option 2)	4,450,671,032	$	0.034904	155,346,222	4,450,671,032	0.038499	171,346,384
	10,324,295,000			396,824,727			437,695,259
Sub-Total -- Base Rates				536,790,643			592,121,363
FAC	10,324,295,000		0.00749	77,306,791			77,306,791
Environmental Surcharge	$ 614,097,434		13.73%	84,331,966			84,331,966
Total Billings				698,429,400			753,760,120

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current			Current	Proposed		Proposed
	Billing Units		Rate	Current $	Billing Units	Rate	Proposed $
RATE B - 9 Customers							
Demand Charge							
Minimum Demand	1,583,516	$	6.22	9,849,470	1,583,516	6.86	10,862,920
Excess Demand	22,484	$	8.65	194,487	22,484	9.54	214,497
	1,606,000						
Energy Charge	kWh						
All kWh	993,758,000	$	0.033455	33,246,174	993,758,000	0.036901	36,670,664
Sub-Total -- Base Rates				43,290,130			47,748,081
FAC	993,758,000		0.00749	7,441,113			7,441,113
Environmental Surcharge	$ 50,731,243		13.73%	6,966,754			6,966,754
Total Billings				$ 57,697,996			$ 62,155,947
RATE C - 6 Customers							
Demand Charge							
All Kw	725,081	$	6.22	4,510,004	725,081	6.86	4,974,056
Energy Charge	kWh						
All kWh	390,942,617	$	0.033455	13,078,985	390,942,617	0.036901	14,426,174
Sub-Total -- Base Rates				17,588,989			19,400,229
FAC	390,942,617		0.00749	2,927,320			2,927,320
Environmental Surcharge	$ 20,516,309		13.73%	2,817,437			2,817,437
Total Billings				$ 23,333,746			$ 25,144,986

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $	Proposed Billing Units	Proposed Rate	Proposed $
RATE G - 2 Customers						
Meter Pt Charge	12	125	1,500	12	138.00	1,656
Substation charges						
Substation 1,000 - 2,999 kVa	-	$ 944				
Substation 3,000 - 7,499 kVa	-	2,373				
Substation 7,500 - 14,999 kVa	-	2,855				
Substation > 15,000 kVa	12	4,605	55,260	12	5,079.00	60,948
Demand Charge						
All Kw	542,919	$ 6.06	3,290,089	542,919	6.68	3,626,699
Energy Charge	kWh					
All kWh	356,767,383	$ 0.031690	11,305,958	356,767,383	0.034954	12,470,447
Sub-Total -- Base Rates			14,652,808			16,159,750
FAC	356,767,383	0.00749	2,671,421			2,671,421
Environmental Surcharge	$ 17,324,229	13.73%	2,379,079			2,379,079
Total Billings			19,703,308			21,210,250

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

	Current			Proposed		
Description	Billing Units	Rate	Current $	Billing Units	Rate	Proposed $
Large Special Contract						
Demand Charge						
Firm Demand	180,000	$ 6.06	1,090,800	180,000	6.68	1,202,400
10-Min Inturruptible Demand	1,440,000	$ 2.46	3,542,400	1,440,000	2.71	3,902,400
90-Min Inturruptible Demand	300,000	$ 3.36	1,008,000	300,000	3.71	1,113,000
	1,920,000					
Energy Charge	kWh					
On-Peak	288,492,371	$ 0.033780	9,745,272	288,492,371	0.037259	10,748,937
Off-Peak	680,257,629	$ 0.030780	20,938,330	680,257,629	0.033950	23,094,747
	968,750,000					
Sub-Total -- Base Rates			36,324,802			40,061,484
FAC	968,750,000	0.00749	7,253,856			7,253,856
Environmental Surcharge	$ 43,578,659	13.73%	5,984,513			5,984,513
Total Billings			49,563,171			53,299,853
						3,736,682

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $	Proposed Billing Units	Proposed Rate	Proposed $
Special Contract - Pumping Stations - 2 Customers						
Demand Charge						
All Kw	467,000	$ 1.75	817,250	467,000	$ 1.75	817,250
Energy Charge	kWh					
Off-Pk Jun-Dec	46,363,340	$ 0.004440	205,853	46,363,340	$ 0.004440	205,853
Off-Peak Jan-May	45,726,810	$ 0.004460	203,942	45,726,810	$ 0.004460	203,942
	92,090,150		409,795			409,795
Monthly Revenue						
Off Peak Fuel/Purchased Power Cost Recovery			3,306,725			3,306,725
Sub-Total -- Base Rates			4,533,770			4,533,770
Environmental Surcharge	4,533,770	13.73%	622,608			622,608
On Peak Fuel/Purchased Power Cost Recovery			6,174,617			6,174,617
Total Billings			11,330,994			11,330,994

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $	Proposed Billing Units	Proposed Rate	Proposed $
Steam Service						
Demand Charge						
Per MMBTU	3,790	$ 500.49	1,897,068	3,790	552.040	2,092,464
Energy Charge	MMBTU					
Per MMBTU	2,228,233	$ 3.577	7,970,390	2,228,233	3.945	8,790,380
Sub-Total -- Base Rates			9,867,458			10,882,844
FAC	260,384,000	0.00749	1,949,717			1,949,717
Environmental Surcharge	$ 11,817,175	13.73%	1,622,813			1,622,813
Total Billings			13,439,988			14,455,374
Total Base Rate Revenue EKPC Members			669,223,217			737,082,138
Total FAC			99,550,218			99,550,218
Total ES			104,725,170			104,725,170
Total EKPC Member Revenue			873,498,604			941,357,525

Seelye Exhibit 10

Forecasted Period Phase II
Summary
Rate Impact Test Year Ended May 31, 2010

	Current	Proposed	$ Incr	% Incr
Rate E	698,429,400	753,775,327	55,345,926	7.92%
Rate B	57,697,996	62,333,404	4,635,408	8.03%
Rate C	23,333,746	25,502,456	2,168,710	9.29%
Rate G	19,703,308	21,561,891	1,858,583	9.43%
Large Special Contract	49,563,171	52,580,542	3,017,371	6.09%
Steam Service	13,439,988	14,113,041	673,053	5.01%
Pumping Stations	11,330,994	11,330,994	-	0.00%
Total	873,498,604	941,197,656	67,699,051	7.75%

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current				Proposed		
	Billing Units	Rate	Current $		Billing Units	Rate	Proposed $
RATE E							
Metering Point Charge				Metering Point Charge			
All Customers	3,734	$ 125.00	466,750	All Customers	3,734	230.00	858,820
Substation charges				Substation charges			
				Substation 1,000-4,999 kVa	48	1,168.00	56,064
				Substation 5,000-9,999 kVa	396	3,087.00	1,222,452
Substation 1,000 - 2,999 kVa	36	$ 944	33,984	Substation 10,000-14,999 kVa	2,513	4,265.00	10,717,945
Substation 3,000 - 7,499 kVa	504	2,373	1,195,992	Substation 15,000-29,999 kVa	645	9,220.00	5,946,900
Substation 7,500 - 14,999 kVa	2,544	2,855	7,263,120	Substation 30,000-50,999 kVa	48	14,488.00	695,424
Substation > 15,000 kVa	578	4,605	2,661,690	Substation > 51,000 kVa	12	16,155.00	193,860
	3,662		11,154,786		3,662		18,832,645
Demand Charge				Demand Charge Rate E			
Option 1 (Owen)	2,343,000	$ 6.92	16,213,560	All kW	23,824,000	10.10	240,622,400
Option 2	21,481,000	$ 5.22	112,130,820				-
	23,824,000		128,344,380				240,622,400
Energy Charge	kWh			Energy Charge			
On-Peak (Option 1)	564,787,000	$ 0.035406	19,996,849	On-Peak kWh	5,346,971,968	0.032382	173,145,646
Off-Peak (Option 1)	526,652,000	$ 0.034904	18,382,261	Off-Peak kWh	4,977,323,032	0.031880	158,677,058
On-Peak (Option 2)	4,782,184,968	$ 0.042470	203,099,396				-
Off-Peak (Option 2)	4,450,671,032	$ 0.034904	155,346,222				-
	10,324,295,000		396,824,727				331,822,705
Sub-Total -- Base Rates			536,790,643	Sub-Total -- Base Rates			592,136,570
FAC	10,324,295,000	0.00749	77,306,791	FAC			77,306,791
Environmental Surcharge	$ 614,097,434	13.73%	84,331,966	Environmental Surcharge			84,331,966
Total Billings			698,429,400	Total Billings			753,775,327

Annual Increase Rate E

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current				Description	Proposed		
	Billing Units	Rate		Current $		Billing Units	Rate	Proposed $
RATE B								
Demand Charge					Demand Charge			
Minimum Demand	1,583,516	$	6.22	9,849,470	Minimum Demand	1,583,516	9.92	15,708,479
Excess Demand	22,484	$	8.65	194,487	Excess Demand	22,484	12.35	277,677
	1,606,000							
Energy Charge	kWh				Energy Charge			
All kWh	993,758,000	$	0.033455	33,246,174	All kWh	993,758,000	0.032140	31,939,382
Sub-Total -- Base Rates				43,290,130	Sub-Total -- Base Rates			47,925,538
FAC	993,758,000		0.00749	7,441,113	FAC			7,441,113
Environmental Surcharge	$ 50,731,243		13.73%	6,966,754	Environmental Surcharge			6,966,754
Total Billings				$ 57,697,996	Total Billings			$ 62,333,404
RATE C	Billing Units	Rate		Existing $		Billing Units	Rate	Proposed $
Demand Charge					Demand Charge			
All kW	725,081	$	6.22	4,510,004	All kW	725,081	9.92	7,192,804
Energy Charge	kWh				Energy Charge			
All kWh	390,942,617	$	0.033455	13,078,985	All kWh	390,942,617	0.032140	12,564,896
Sub-Total -- Base Rates				17,588,989	Sub-Total -- Base Rates			19,757,699
FAC	390,942,617		0.00749	2,927,320	FAC			2,927,320
Environmental Surcharge	$ 20,516,309		13.73%	2,817,437	Environmental Surcharge			2,817,437
Total Billings				$ 23,333,746	Total Billings			$ 25,502,456

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description		Current Billing Units		Current Rate	Current $	Description	Proposed Billing Units	Proposed Rate	Proposed $
RATE G									
Meter Pt Charge		12		125	1,500	Meter Pt Charge	12	230.00	2,760
Substation Charges						Substation Charges			
Substation 1,000 - 2,999 kVa		-	$	944					
Substation 3,000 - 7,499 kVa		-		2,373					
Substation 7,500 - 14,999 kVa		-		2,855					
Substation > 15,000 kVa		12		4,605	55,260	Substation > 51,000 kVa	12	16,155.00	193,860
Demand Charge						Demand Charge			
All Kw		542,919	$	6.06	3,290,089	All Kw	542,919	8.93	4,848,267
Energy Charge	kWh					Energy Charge			
All kWh		356,767,383	$	0.031690	11,305,958	All kWh	356,767,383	0.032140	11,466,504
Sub-Total -- Base Rates					14,652,808	Sub-Total -- Base Rates			16,511,390
FAC		356,767,383		0.00749	2,671,421	FAC			2,671,421
Environmental Surcharge	$	17,324,229		13.73%	2,379,079	Environmental Surcharge			2,379,079
Total Billings					19,703,308	Total Billings			21,561,891

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $	Description	Proposed Billing Units	Proposed Rate	Proposed $
Large Special Contract							
Demand Charge				Demand Charge			
Firm Demand	180,000	$ 6.06	1,090,800	Firm Demand	180,000	8.93	1,607,400
10-Min Inturruptible Demand	1,440,000	$ 2.46	3,542,400	10-Min Inturruptible Demand	1,440,000	3.63	5,227,200
90-Min Inturruptible Demand	300,000	$ 3.36	1,008,000	90-Min Inturruptible Demand	300,000	4.93	1,479,000
	1,920,000						
Energy Charge	kWh			Energy Charge			
On-Peak	288,492,371	$ 0.033780	9,745,272	On-Peak	288,492,371	0.032382	9,341,960
Off-Peak	680,257,629	$ 0.030780	20,938,330	Off-Peak	680,257,629	0.031880	21,686,613
	968,750,000						
Sub-Total -- Base Rates			36,324,802	Sub-Total -- Base Rates			39,342,173
FAC	968,750,000	0.00749	7,253,856	FAC			7,253,856
Environmental Surcharge	$ 43,578,659	13.73%	5,984,513	Environmental Surcharge			5,984,513
Total Billings			49,563,171	Total Billings			52,580,542

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $	Description	Proposed Billing Units	Proposed Rate	Proposed $
Special Contract - Pumping Stations							
Demand Charge				**Demand Charge**			
All Kw	467,000	$ 1.75	817,250	All Kw	467,000	$ 1.75	817,250
Energy Charge	kWh			**Energy Charge**			
Off-Pk Jun-Dec	46,363,340	$ 0.004440	205,853	Off-Pk Jun-Dec	46,363,340	$ 0.004440	205,853
Off-Peak Jan-May	45,726,810	$ 0.004460	203,942	Off-Peak Jan-May	45,726,810	$ 0.004460	203,942
			409,795				409,795
Monthly Revenue							
Off Peak Fuel/Purchased Power Cost Recovery			3,306,725	Off Peak Fuel/Purchased Power Cost Recovery			3,306,725
Sub-Total -- Base Rates			4,533,770	Sub-Total -- Base Rates			4,533,770
Environmental Surcharge	4,533,770	13.73%	622,608	Environmental Surcharge			622,608
On Peak Fuel/Purchased Power Cost Recovery			6,174,617	On Peak Fuel/Purchased Power Cost Recovery			6,174,617
Total Billings			11,330,994	**Total Billings**			11,330,994

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $		Proposed Billing Units	Proposed Rate	Proposed $
Steam Service							
Demand Charge Per MMBTU	3,790	$ 500.49	1,897,068	Demand Charge Per MMBTU	3,790	572.830	2,171,267
Energy Charge Per MMBTU	2,228,233	$ 3.577	7,970,390	Energy Charge Per MMBTU	2,228,233	3.756	8,369,244
Sub-Total -- Base Rates			9,867,458	Sub-Total -- Base Rates			10,540,511
FAC	260,384,000	0.00749	1,949,717	FAC			1,949,717
Environmental Surcharge	$ 11,817,175	13.73%	1,622,813	Environmental Surcharge			1,622,813
Total Billings			13,439,988	Total Billings			14,113,041
Total Base Rate Revenue EKPC Members			669,223,217				736,922,268
Total FAC			99,550,218				99,550,218
Total ES			104,725,170				104,725,170
Total Member Revenue			873,498,604				941,197,656