COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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|---|---|---|
| GENERAL ADJUSTMENT OF ELECTRIC | ) | |
| RATES OF EAST KENTUCKY POWER | ) | CASE NO. |
| COOPERATIVE, INC. | ) | 2010-000167 |

**DIRECT TESTIMONY**

**AND EXHIBITS**

**OF**

**STEPHEN J. BARON**

ON BEHALF OF

GALLATIN STEEL COMPANY

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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| GENERAL ADJUSTMENT OF ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC. | ) ) ) | CASE NO. 2010-000167 |

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# DIRECT TESTIMONY OF STEPHEN J. BARON

## I. QUALIFICATIONS AND SUMMARY

**Q. Please state your name and business address.**

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

**Q. What is your occupation and by who are you employed?**

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

**Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.**

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

**Q. Please state your educational background and experience.**

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida.

I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court.

A complete copy of my resume and my testimony appearances is contained in Baron Exhibit__(SJB-1).

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of Gallatin Steel Company ("Gallatin"), a Large Special Contract customer of East Kentucky Power Cooperative, Inc. ("EKPC" or the "Company") and the Owen Electric Cooperative.

**Q. What is the purpose of your testimony?**

A. I am responding to EKPC's rate filing on a variety of cost of service and rate design issues. EKPC elected not to file a class cost of service study in this case. In lieu of a cost of service analysis, EKPC is proposing a uniform percentage increase to each rate class. I have prepared a class cost of service study that uses, for the most part, the methodology sponsored by EKPC witness Steven Seelye in EKPC's 2008 general rate case, Case No. 2008-00409. As I will discuss, based on the results of the Gallatin cost of service analysis, the Large Special Contract class ("LSC") should receive a lower than average increase in this case.

The second issue that I address concerns EKPC's 10-minute interruptible demand credit applicable to Gallatin Steel. EKPC is not proposing to change this credit (or the 90-minute notice interruptible credit) in this case. I am proposing an increase in the 10-minute interruptible credit to recognize the full avoided capacity cost associated with a combustion turbine generating unit. Specifically, the EKPC 10-minute interruptible credit should be adjusted to include an avoided planning reserve margin of 12%. While some adjustment for reserves would be appropriate for the 90-minute interruptible credit also, Gallatin is not proposing any increase in EKPC's current 90-minute interruptible rate.

**Q. Would you please summarize your testimony?**

A. Yes. I recommend and conclude the following:

- **The Commission should adopt the Gallatin class cost of service study to apportion the requested revenue increase in this case. This study, which reflects for the most part a class cost of service methodology supported by EKPC in its 2008 rate case, shows that the Large Special Contract class should receive a lower than average rate increase in this case. At the EKPC requested 5.27% overall revenue increase, the Large Special Contract class should receive a 4.4% increase, not including the effect of Gallatin's proposed increase in the 10-minute interruptible credit.**

- **EKPC's proposed Large Special Contract 10-minute interruptible rate credit of $5.60 per kW should be adjusted to reflect avoided capacity reserves associated with interruptible load. This adjustment increases the interruptible credit to $6.22 per kW.**

- **In addition, EKPC's general Interruptible Service rate (tariff Section D) should be revised to remove the current 20 mW customer load cap. In light of EKPC's expected future load growth and need for peak capacity, there is no basis for this limitation.**

## II. CLASS COST OF SERVICE ISSUES AND THE APPROPRIATE LARGE SPECIAL CONTRACT REVENUE INCREASE

<u>Cost of Service</u>

**Q. Did EKPC file a class cost of service study in this case in support of its recommended rate class increases?**

A. No. Company witness Isaac Scott addresses EKPC's proposed apportionment of the overall revenue increase in this case and recommends a uniform (pro-rata) percentage increase to each rate class. Mr. Scott explains that he did not present or rely on a class cost of service study because EKPC is in the process of conducting a rate design study that was not available at the time of the EKPC rate filing.

**Q. Do you believe that it is appropriate to consider cost of service to support the apportionment of the approved EKPC revenue increase to rate classes in this case?**

A. Yes. In its 2008 rate case, EKPC prepared and filed a full class cost of service study using a traditional 6 coincident peak allocation methodology to assign fixed production costs to rate classes and a 12 coincident peak methodology to assign transmission costs. As I discussed in my testimony in Case No. 2008-00409, EKPC's cost of service methodology in that case was generally appropriate and a proper basis to guide the apportionment of the increase to rate classes.

**Q. You indicated that EKPC's prior methodology was "generally appropriate" to use in a class cost of service study. Did you make any adjustments to the EKPC study in the 2008 case?**

A. Yes. While accepting the production and transmission allocation methodology, I did recommend a more refined approach to allocate fuel and purchased energy expenses to rate classes. Specifically, I adjusted the EKPC study (which was prepared and supported by EKPC witness Steven Seelye) to reflect a monthly allocation of fuel and purchased energy expenses. This adjustment provided a more precise assignment of cost responsibility that recognized seasonal variations in fuel and purchased energy expenses.

**Q. Have you prepared a test year class cost of service study following EKPC's 2008 methodology?**

A. Yes. Through discovery, I have obtained the necessary information to develop a full class cost of service study that allocates the 2011 test year revenue requirements to each of EKPC's rate classes, including the Large Special Contract class. This study, which is presented in Baron Exhibit__(SJB-2), utilizes the functionalized cost of service data presented by EKPC witness Dennis Eicher as the starting point. I then utilized EKPC's 2008 class cost of service methodology, with some adjustments that I will discuss subsequently, to allocate EKPC's 2011 test year costs to each rate class. Finally, as I will discuss later in my testimony, I present a recommended apportionment of the revenue increase to the Large Special Contract class and all other EKPC rate classes.

Q. **Would you provide a brief overview of the general methodology you used in your cost of service study?**

A. Yes. I generally relied on the methodology used by EKPC in its prior rate case in 2008. As described by its witness in that case, Steven Seelye, the EKPC cost of service study utilized a 6 coincident peak allocation for production demand costs and 12 CP for transmission costs.

Following EKPC's 2008 cost of service methodology, I developed a class cost of service study by first functionalizing all of EKPC's future test year plant and expenses, classifying these costs as either demand-related, energy-related or customer-related and then allocated the functionalized/classified costs to customer classes using the same allocation methodology recommended by Mr. Seelye on behalf of EKPC; though as in the 2008 rate case I did make several adjustments that I will discuss subsequently.

**Q. EKPC witness Dennis Eicher developed functionalized test year costs in this case. Did you rely on his results to develop the functional cost of service inputs into your analysis?**

A. Yes. For the most part, Mr. Eicher's cost functionalization followed the methodology used by Mr. Seelye in EKPC's 2008 rate case. However, in cases where there were methodological differences, I applied EKPC's 2008 (Mr. Seelye's) functional cost methodology to the EKPC 2011 test year data to develop the Gallatin class cost of service study that I am presenting in this case.

**Q. Did you follow Mr. Seelye's methodology for cost classification and allocation?**

A. Yes. Each of the functionalized costs are classified as either demand, energy or customer following the 2008 EKPC method. I relied on the same allocation factors, updated to the 2011 EKPC test year, to allocate costs to rate classes. EKPC provided the data to develop these updated allocation factors in response to discovery in this case.

**Q. You indicated that you made some adjustments to the basic EKPC cost of service methodology. Would you explain each of these adjustments?**

A. Yes. The first adjustment that I made is to provide a more detailed allocation of purchased power and fuel expense, recognizing seasonal and time of day cost differences in the allocation process. In EKPC's originally filed 2008 study, Mr. Seelye allocated all fuel and purchased power costs on the basis of rate schedule energy. Though this is a reasonable approach, a more detailed allocation can be made and is justified in cases where there are material differences in these energy costs by season and time-of-day.

On an aggregate basis, fuel and purchased power expenses and revenues are removed from the cost of service study in the analysis. The adjustment that I made thus reflects only the differences, on a class by class basis, between allocated cost using a detailed monthly energy allocation and an annual energy allocation. On a total EKPC basis, these differences sum to zero; however for each rate class the difference is either positive or negative. These adjustments are shown on pages 16 to 17 of Exhibit__(SJB-2).

The first of these allocations concerns EKPC's test year fuel expenses. In my revised analysis, these expenses are disaggregated monthly and allocated based on monthly energy use to rate classes.

The second allocation concerns EKPC's test year purchased power expenses. The Company has determined that 67% of these test year expenses are incurred during the on-peak period and 33% in the off-peak period. I have separately allocated the on and off-peak amounts using rate class kWh energy usage during the same on and off-peak periods.

I also adjusted EKPC's projected test year level of Gallatin revenues (Large Special Contract class) by revising the on-peak/off-peak mix of mWh energy usage to reflect recent Gallatin consumption patterns. While I continue to use EKPC's projected test year overall level of mWh sales to Gallatin, I revised the projected test year revenues of Gallatin from \$48.534 million to \$48.698 million by increasing the percentage of on-peak usage from 24.84% to 29.4%. This revised on-peak percentage is equivalent to Gallatin's load characteristics for the 12 months ended June 2010, which is a more reasonable projection of Gallatin's future on-peak usage percentage.

**Q. Did you make any additional modifications to the basic EKPC cost of service methodology that was presented by Mr. Seelye on behalf of EKPC in the 2008 rate case?**

A. Yes. I modified the treatment of interruptible load in the cost of service study. EKPC recognized interruptible load in its 2008 cost of service study by crediting interruptible revenue credits to the Large Special Contract class and simultaneously allocating the cost of these credits to all rate classes, including the LSC class. That is reasonable and I have done the same here.[1]

The specific adjustment that I made in my cost of service analysis that I present in Exhibit__(SJB-2) recognizes the value of fuel savings produced when Gallatin Steel, the Large Special Contract Customer, is interrupted. Pursuant to Gallatin's contract with EKPC, 120,000 kW of Gallatin's load can be interrupted on 10-minute notice, with an additional 25,000 kW of Gallatin load subject to 90-minute interruption. Per the agreement, this load (145,000 kW) can be interrupted up to 360 hours annually. During each such interruption, Gallatin reduces its load by the specified contract amounts, thus reducing the need for higher cost generation and purchased power resources for the entire EKPC system. This in turn, reduces the average EKPC fuel expense. Absent an interruption, EKPC would be required to either generate or purchase energy to serve this 145,000 kW of load at incremental cost during the hours of interruption.

**Q. Is this "fuel saving" value included in the interruptible credit provided to Gallatin in exchange for its non-firm, interruptible service?**

[1] In the base year in this case, EKPC shows a small amount of interruptible load for other rate classes. In the projected test year, EKPC only shows Gallatin interruptible load, which was also the case in the 2008 rate case projected test year.

A. No. As I will discuss in the next section of my testimony (regarding a proper 10-minute interruptible credit based on avoided capacity cost), Gallatin receives interruptible credits based on the reliability (capacity) value of its interruptible load only. No recognition is given in the existing interruptible credit to reflect the "fuel savings" value produced by interruptions. While I am not recommending a change in the Large Special Contract interruptible credit to reflect this "fuel savings" value, it should be recognized in the class cost of service study, in the same manner as the reliability value is recognized.

**Q. Did you make a similar adjustment to reflect fuel savings associated with interruptible load that occurs in other EKPC rate schedules?**

A. Such an adjustment would be appropriate; however, EKPC is not projecting any interruptible load beyond the Gallatin load in the future test year.

**Q. Would you provide an illustration of how Gallatin interruptions provide fuel savings benefits ("value") to the EKPC firm customers?**

A. Yes. Table 1 below provides an illustration of how interruptions of Gallatin load provide fuel savings benefits to all of EKPC's other customers.

**Table 1**
**Illustration of Interruptible Load Fuel Savings**
**(impact during 1 hour)**

| | | No Interruptible Load | | With Interruptible Load* | |
|---|---|---|---|---|---|
| Resource | $/mWh | mWh | Cost | mWh | Cost |
| Coal | 22 | 1000 | 22000 | 1000 | 22000 |
| Gas | 45 | 600 | 27000 | 600 | 27000 |
| Purchase | 55 | 300 | 16500 | 200 | 11000 |
| Total | | 1900 | 65500 | 1800 | 60000 |
| Average Fuel Rate | | | $ 34.47 | | $ 33.33 |

* Assumes 100 mW of interruptible load is interrupted

In this illustration of the fuel savings impact of interruptible load during 1 hour, it is assumed that there is 100 mW of interruptible load. In the first scenario, it is assumed that the 100 mW of Special Contract load is firm and is included in the 1900 mW during the hour of total system load. Based on a mix of coal, gas and purchases, the average fuel cost that would be charged to all EKPC customers is $34.47 per mWh. In the second scenario, it is assumed that the 100 mW of Special Contract load is interruptible and is interrupted during the hour. In this case, the system uses only 200 mW during the hour of $55/mWh purchases, thus saving $5,500. The resulting average fuel rate that is paid by firm EKPC customers is now only $33.33/mWh, resulting in fuel savings to these firm customers as a result of interrupting the Special Contract load.

**Q. Does it make any difference in the fuel savings benefits if Gallatin is buying through an economic interruption?**

A. No. Pursuant to the approved Gallatin contract and the tariff, Gallatin can elect to buy-through an economic interruption by paying the full incremental costs associated with obtaining replacement power. The revenues paid by Gallatin during such a buy-through event fully offset the cost of the buy-through and thus other EKPC customers are indifferent from an economic and rate perspective. In other words, the buy-through, which is an independent transaction between Gallatin and EKPC has no effect on the rates of other customers.

More significantly, whether or not Gallatin elects to buy-through an economic interruption, EKPC's firm customers still receive the fuel savings benefit made possible by the interruption. Consider the case in which Gallatin chooses not to buy-through the interruption. In this case Gallatin reduces its load by 145,000 kW in each hour during the interruption, resulting in lower average EKPC fuel and purchased energy costs – the "fuel savings" that I discussed above. Now consider the case in which Gallatin elects to buy-through the interruption. The other EKPC customers still receive the same fuel savings benefit from the interrupted Gallatin load; Gallatin simply pays the incremental cost of obtaining replacement power in a separate financial transaction. Gallatin Steel has bought-through interruptions as recently as 2008 for 19.6 cents/kWh. This is a cost which other ratepayers therefore avoided. My cost of service study simply factors in this system benefit.

**Q. Would you please describe the specific adjustment that you made in the class cost of service study to reflect the interruptible "fuel savings" associated with Gallatin interruptible load?**

A. Yes. The first step in the analysis was to develop the fuel savings provided by interrupting 1 kW of load for 360 hours per year, the contract limit on annual hours of interruption. This represents the fuel savings benefit of Gallatin interruptible load. To calculate the fuel savings, I used EKPC's mWh energy weighted average test year purchased energy expense, reduced by the $6.50/mWh call option, as the basis for avoided energy cost associated with interruption hours. EKPC's response to Gallatin's first set of data requests, Request No. 7, provides this information. I have attached this response as Baron Exhibit__(SJB-3). This avoided energy rate per mWh, which I calculated to be $67.96/mWh, is then multiplied by Gallatin's 145 mW of interruptible load and "360," the number of hours of annual interruption permitted by Gallatin's interruptible rate. This "fuel savings" amount, which I computed to be $3.547 million for the 2011 test year is credited to the Large Special

Contract class and allocated to all rate classes, including the LSC class, on the basis of energy.[2]

**Q. What are the results of the Gallatin adjusted class cost of service study?**

A. Baron Exhibit__(SJB-2) presents the Gallatin class cost of service study. Table 2 below summarizes the rates of return at present EKPC rates, using EKPC's test year costs presented by EKPC witness Eicher in his Exhibit DRE-2 (as modified functionally to reflect the EKPC 2008 method) and the allocation methodology that I discussed above. Also shown are the relative rate of return index values, which measure the rate of return of each rate class on a relative basis to the system average rate of return (if the "Index" equals 1.0, then the rate class is at the system average rate of return) and the dollar subsidies paid and received by each rate class. The dollar subsidy, if a positive value, represents the excess amount paid by a rate class above the cost of actually providing electric service to the class. If the subsidy value is negative, it means that a rate class is receiving subsidized electric service, with the subsidy representing the difference between the cost to provide electric service to the customers in that class and the rates paid by these customers for power.

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[2] This is the same methodology used to reflect the reliability value of interruptible load used in the 2008 EKPC cost of service study.

| Table 2<br>Results of Test Year COSS<br>Present Rates | | | |
|---|---|---|---|
| | Rate of Return | Relative ROR | Dollar Subsidy |
| Rate E | 3.83% | 0.975 | (2,512,766) |
| Rate B | 4.33% | 1.102 | 551,492 |
| Rate C | 4.12% | 1.048 | 85,903 |
| Rate G | 2.32% | 0.591 | (830,180) |
| Large Special Contract | 4.36% | 1.110 | 753,638 |
| Spc Cont Pumping Stations | 8.27% | 2.104 | 288,663 |
| Steam Service | 14.98% | 3.813 | 1,663,249 |
| Total | 3.93% | 1.000 | (0) |

As can be seen from Table 2, the rate of return for the Large Special Contract class exceeds the system average rate of return at present rates (4.36% versus a an average rate of return of 3.93%). More significantly, the Large Special Contract class is paying $753,638 in subsidies to EKPC's other customers; effectively, Gallatin Steel is currently overpaying for its power from EKPC by $753,638.

<u>**Apportionment of the Overall Revenue Increase to Rate Classes**</u>

**Q. Have you developed an analysis of class cost of service at EKPC's requested class rate increases in this case?**

A. Yes. EKPC is requesting a TIER of 1.50 in this case. Following the methodology of EKPC witness Eicher, I have converted this TIER requirement into an equivalent rate of return on investment, which can then be used to compute class revenue requirements at proposed rates. Table 3 below summarizes the class rates of return, relative rates of return and dollar subsidies based on EKPC's proposed rate increases in this case. As can be seen, the dollar subsidies that will be paid by Gallatin have actually increased to $980,258 under EKPC's proposals in this case.

**Table 3**
**Results of Test Year COSS**
**EKPC Proposed Rates**

| | Rate of Return | Relative ROR | Dollar Subsidy |
|---|---|---|---|
| Rate E | 5.42% | 0.970 | (4,218,107) |
| Rate B | 6.49% | 1.162 | 1,247,236 |
| Rate C | 6.30% | 1.128 | 324,828 |
| Rate G | 4.27% | 0.765 | (678,919) |
| Large Special Contract | 6.15% | 1.100 | 980,258 |
| Spc Cont Pumping Stations | 8.27% | 1.480 | 178,336 |
| Steam Service | 19.98% | 3.577 | 2,166,368 |
| Total | 5.59% | 1.000 | (0) |

**Q. Based on the results of your cost of service analysis, what is your recommendation to apportion the approved revenue increase in this case to rate classes?**

A. I am recommending that the Large Special Contract class receive an increase based on full cost of service, with a full elimination of subsidies. Table 4 below presents the proposed increases that I am recommending.

**Table 4**
**Gallatin Proposed Rate Increases**

| | Present Revenues | Proposed Increase | Percent Increase |
|---|---|---|---|
| Rate E | 771,730,098 | 41,382,761 | 5.36% |
| Rate B | 56,378,640 | 3,042,756 | 5.40% |
| Rate C | 18,785,745 | 1,014,546 | 5.40% |
| Rate G | 19,002,098 | 1,027,832 | 5.41% |
| Large Special Contract | 48,697,556 | 2,141,359 | 4.40% |
| Spc Cont Pumping Stations | 9,009,512 | - | 0.00% |
| Steam Service | 14,076,304 | 768,193 | 5.46% |
| Total | 937,679,954 | 49,377,447 | 5.27% |

Based on EKPC's requested $49.4 million increase in this case, this would produce a $2.14 million LSC increase. The remaining $47.24 million increase to all other rate classes should be assigned on a pro-rata basis in the manner proposed by EKPC witness Scott. The increases shown in Table 4 assume that EKPC receives its full requested revenue increase of $49.377 million.

**Q. Why is it appropriate to distinguish between the Large Special Contract rate class and all other EKPC rate classes, as you have proposed?**

A. Gallatin Steel, EKPC's Large Special Contract customer, takes service from EKPC (via Owen Electric Cooperative) pursuant to a specific contract that distinguishes this customer from all other EKPC customers. The current Gallatin contract has been temporarily extended until November 2010 and requires, among other things, for Gallatin to specifically pay for load following and regulation service, which can be as high as $300,000 per month. I have been informed by Gallatin Counsel that the new Gallatin contract will likely contain additional charges for regulation service, as well as load following and that the amounts charged to Gallatin for the "services" can be as high as $5.1 million per year. No other customer on EKPC is required to pay similar charges. These charges are in addition to all of the tariff based charges that Gallatin pays for electric service on the EKPC system.

Q. **What is the implication of these "extra-tariff" provisions that are applicable only to Gallatin?**

A. In my opinion, it means that Gallatin is effectively being treated as a standalone customer, paying both cost of service based rates (or, as I have previously discussed, excess-cost of service based rates), plus other charges (load following, regulation service) that are imposed due to its unique characteristics. The benefits and burdens associated with service to Gallatin are therefore unique on the EKPC system. It would be unjust and unreasonable to require Gallatin to pay up to $5.1 million per year in special load following and regulation charges in recognition of its unique costs that EKPC has determined Gallatin to be responsible for, and at the same time require Gallatin to pay subsidies (payments above cost of service) for its tariff service. This would amount to a "heads I win; tales you lose" arrangement. It would be unjust and unreasonable to impose a strict cost responsibility standard for some costs (load following and regulation) and not other costs (all other base rate cost of service items). This includes, as I discussed previously, full recognition of the value provided by Gallatin in the form of interruptible load to EKPC – both the reliability value for which Gallatin receives an interruptible rate credit for its interruptible load and a "fuel savings" component which is not reflected in Gallatin's interruptible credit. Due to Gallatin's unique "standalone" customer characteristics, the Large Special Contract rate should not include extra charges associated with subsidy payments to other EKPC customers.

**Q. Would you summarize your recommendation to apportion the Commission approved EKPC overall revenue increase to rate classes?**

A. Yes. Gallatin should receive an increase such that it pays cost of service rates, with no excess charges for subsidies to other rate classes. For all other EKPC rate classes, I recommend that the remaining revenue increase (after the Gallatin Large

Special Contract increase is accounted for) be applied on a uniform percentage basis as proposed by EKPC in this case.

Although I am not offering a legal opinion, I believe that this recommendation is fully consistent with the distribution cooperative flow through statute, KRS 278.455. The proportional flow through process does not apply to "special contracts under which the rates are subject to change or adjustment only as stipulated in the contract." The Gallatin Steel contract is exactly this type of special contract. I will address the cost allocation issue in greater detail in the Owen Electric rate case. Case No. 2010-00179.

**Q. In the likely event that the Commission does not authorize EKPC to receive its full requested revenue increase in this case, do you have a recommendation to scale-back the proposed increases shown in Table 4?**

A. Yes. I recommend that the dollar increases shown in Table 4 for the Large Special Contract class and all other EKPC rate classes be reduced by a uniform percentage basis to match the approved increase. For example, if the Commission approved an overall increase of $35 million (instead of the EKPC requested increase of $49.4 million), the results shown in Table 4 should be adjusted as shown in my Table 5 below.

**Table 5**
**Gallatin Proposed Class Rate Increases**
**at $35 Million Overall Increase**

| | Gallatin Proposed Increases at Full Rate Request | Scaled-back Increases @ $35 Million |
|---|---|---|
| Rate E | 41,382,761 | 29,333,162 |
| Rate B | 3,042,756 | 2,156,783 |
| Rate C | 1,014,546 | 719,136 |
| Rate G | 1,027,832 | 728,553 |
| Large Special Contract | 2,141,359 | 1,517,850 |
| Spc Cont Pumping Stations | - | - |
| Steam Service | 768,193 | 544,515 |
| Total | 49,377,447 | 35,000,000 |

## III. INTERRUPTIBLE RATE ISSUES

**Q. Before discussing specific issues associated with EKPC's Large Special Contract interruptible rates, would you briefly discuss the purpose and benefits of interruptible load on the EKPC system?**

A. Yes. EKPC's Large Special Contract customer is Gallatin Steel. Gallatin takes both firm service and interruptible service with both 10-minute and 90-minute interruptible provisions. These provisions require Gallatin to interrupt a portion of its load within either 10-minutes or 90-minutes of notification by EKPC to do so. EKPC request up to 360 annual hours of interruptions by Gallatin for any reason, up to the specified kW contract demand levels (120,000 kW of 10-minute interruptible load, 25,000 kW of 90-minute interruptible load). While Gallatin receives an interruptible credit based on the "reliability" value of avoided capacity costs which it provides to EKPC and its firm customers, it does not receive any credit associated with the fuel savings benefits provided to other EKPC customers (I addressed the cost of service implication of this later issue earlier in my testimony).

**Q. What are the reliability benefits provided to EKPC and its firm customers by Gallatin's ability to interrupt 120,000 kW of load at 10-minute notice and an additional 25,000 kW of load at 90-minute notice?**

A. Gallatin's interruptible load provides an alternative to additional generating unit resources that EKPC would require if the Gallatin load was firm. EKPC is required, based on its obligation to serve, to obtain generation resources to meet it firm loads, including a 12% reserve margin (which I will discuss subsequently). All else being equal, EKPC would require an additional 162,400 kW (Gallatin interruptible load of 145,000 kW plus 12% reserves) of peaking capacity if the Gallatin load was firm, instead of interruptible. The cost of this additional capacity would be borne by all of EKPC's customers. Because Gallatin has agreed to non-firm interruptible service for 145,000 kW of its total load of 160,000 kW, it receives an interruptible credit set at the cost of capacity that EKPC would otherwise incur if the Gallatin load were firm ("avoided capacity cost").

**Q. Is EKPC's winter peak expected to continue growing over the next 10 years, imposing additional requirements for generating resources to meet the needs of its customers?**

A. Yes. Based on the load forecast presented in EKPC's 2009 Integrated Resource Plan, winter peak load will grow by 650 mW over the next 10 years.[3] EKPC projects that it will require an additional 1,500 mW of resources by 2023 to meet loads, including 350 mW of peaking capacity.[4] Absent the Gallatin interruptible

[3] See EKPC 2009 IRP, page 5-14.

[4] *Id.*, at page 5-16.

load, this requirement would increase substantially. It should also be noted that Gallatin's load is not projected to grow and none of this new planned capacity has been caused by Gallatin.

**Q. Is interruptible load beneficial to the EKPC system in other ways?**

A. Yes. In addition to the reliability benefits in the form of avoided peaking capacity, and the fuel savings provided during hours of interruption, the ability of Gallatin Steel to obtain interruptible service provides a tangible economic benefit to all of EKPC's other customers (and the State of Kentucky) because it contributes to Gallatin's ability to operate in an economically viable manner. This, in turn, creates and preserves jobs, both directly through employment with Gallatin and indirectly through multipliers applied to Gallatin wages and regional purchases of goods and services by Gallatin. Professor Coomes discusses these factors in his testimony.

**Q. Have you reviewed the Company's proposal to maintain the Large Special Contract interruptible credits at current levels in this case?**

A. Yes. As discussed by EKPC witness Isaac Scott at page 3 of his testimony, EKPC is not proposing to revise the current Large Special Contract interruptible credits of \$5.60 per kW of 10-minute interruptible demand and \$4.20 per kW of 90-minute interruptible demand. Mr. Scott presents an analysis of the avoided cost of a simple cycle combustion turbine (Scott Exhibit 1) and concludes that the current credits are appropriate.

**Q. Do you agree with Mr. Scott's Large Special Contract interruptible rate avoided cost analysis?**

A. Not completely. While his analysis generally appears to be reasonable, he did not include any factor to reflect the avoidance of "capacity reserves" in the calculation of avoided capacity cost. EKPC's 2009 Integrate Resource Plan ("IRP") reports that EKPC utilizes a 12% reserve margin for generating capacity planning purposes.[5] This means that EKPC must obtain 1.12 mW of generation capacity for each 1 mW of load. Since 1 mW of interruptible load, if it were "firm," would require 1.12 mW of capacity at a 12% reserve margin, there should be an adjustment in the avoided capacity calculation to reflect these reserves. Mr. Scott's analysis that he presented in his Exhibit 1 did not reflect any "value" associated with this additional reliability benefit, based on the avoided cost of peaking capacity.

**Q. Have you revised Mr. Scott's avoided capacity cost analysis to reflect a 12% reserve margin?**

A. Yes. Table 6 below summarizes my analysis. It is identical to the analysis presented by Mr. Scott in his Exhibit 1 except for the adjustment to reflect the fact

[5] See 8.(5)(d) at page 8-60 of EKPC's 2009 IRP.

avoiding 1 mW of firm load results in 1.12 mW of combustion turbine capacity avoided.

**Table 6**
**Development of Interruptible Credit**

| | Avoided Capacity Cost | |
|---|---|---|
| | **As Filed** | **Adjusted for Reserves** |
| CT Cost | $ 550 | $ 550 |
| Cost of Capital | 7.52% | 7.52% |
| Depreciation | 2.50% | 2.50% |
| Average Term of Financing | 30 | 30 |
| Annual Capacity Cost | $46.66 | $46.66 |
| Fixed O&M Expense | 6.25 | 6.25 |
| Depreciation | 13.75 | 13.75 |
| Annual Cost | $66.66 | $66.66 |
| Reserve Margin | 0% | 12% |
| Total Annual Cost | $66.66 | $74.66 |
| Monthly Cost | $5.55 | $6.22 |

As can be seen from the analysis in Table 6, the avoided capacity cost using a proper analysis, which reflects reserves, produces an interruptible credit of $6.22 per kW. I recommend that the LSC 10-minute interruptible credit be increased to this $6.22

per kW rate from the current \$5.60 per kW rate. I am not recommending any change in the 90-minute interruptible credit at this time.

**Q. Are there any additional issues that you would like to address regarding EKPC interruptible rates?**

A. Yes. EKPC currently has a generally available Interruptible Service rate (Section D of its tariff) that contains a limitation on the size of an ultimate member cooperative customer set a 20 mW. In response to Gallatin Set 1, Request No. 19, EKPC stated that the limitation on customer size was approved by the Commission effective March 14, 1995. EKPC further stated that "The 20 MW limit has been sufficient to date and there has not been an expressed need from Member Cooperatives or retail customers to revise the limit." EKPC's response is attached as Baron Exhibit__(SJB-4).

**Q. Has EKPC provided a reasonable justification for its limitation, which is now 15 years old?**

A. No. As I discussed earlier in my testimony, EKPC is projecting an additional 1,500 of peak demand on its system over the next 12 years and the need for 350 mW of additional peaking capacity. Based on this future growth, the interruptible customer size limitation should be lifted. EKPC has not provided any justification for such a limitation. To the extent that large customers can take a portion of their service under EKPC's interruptible provisions, this would reduce the need for future peaking capacity additions. As such, I recommend that the 20 mW limitation be removed from the Interruptible Service rate.

**Q. Does that complete your testimony?**

A. Yes.

AFFIDAVIT

STATE OF GEORGIA )

COUNTY OF FULTON )

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this 2 day of September, 2010.

Jessica K. I

Notary Public

JESSICA K. INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31ST, 2011
CHEROKEE COUNTY, GA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

| | | |
|---|---|---|
| GENERAL ADJUSTMENT OF ELECTRIC | ) | |
| RATES OF EAST KENTUCKY POWER | ) | CASE NO. |
| COOPERATIVE, INC. | ) | 2010-000167 |

EXHIBITS

OF

STEPHEN J. BARON

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF:**

| | | |
|---|---|---|
| **GENERAL ADJUSTMENT OF ELECTRIC** | ) | |
| **RATES OF EAST KENTUCKY POWER** | ) | **CASE NO.** |
| **COOPERATIVE, INC.** | ) | **2010-000167** |

**EXHIBIT ___(SJB-1)**

**OF**

**STEPHEN J. BARON**

**Professional Qualifications**

**Of**

**Stephen J. Baron**

Mr. Baron graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, he received a Master of Arts Degree in Economics, also from the University of Florida. His areas of specialization were econometrics, statistics, and public utility economics. His thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which he received a grant from the Public Utility Research Center of the University of Florida. In addition, he has advanced study and coursework in time series analysis and dynamic model building.

Mr. Baron has more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, he joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. His responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, he joined the Utility Rate Consulting Division of Ebasco Services, Inc.

as an Associate Consultant. In the seven years he worked for Ebasco, he received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. His responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

He joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity he was responsible for the operation and management of the Atlanta office. His duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, he specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, he joined the consulting firm of Kennedy and Associates as a Vice President and Principal. Mr. Baron became President of the firm in January 1991.

During the course of his career, he has provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

He has presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." His article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, he completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

Mr. Baron has presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 4/81 | 203(B) | KY | Louisville Gas & Electric Co. | Louisville Gas & Electric Co. | Cost-of-service. |
| 4/81 | ER-81-42 | MO | Kansas City Power & Light Co. | Kansas City Power & Light Co. | Forecasting. |
| 6/81 | U-1933 | AZ | Arizona Corporation Commission | Tucson Electric Co. | Forecasting planning. |
| 2/84 | 8924 | KY | Airco Carbide | Louisville Gas & Electric Co. | Revenue requirements, cost-of-service, forecasting, weather normalization. |
| 3/84 | 84-038-U | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Excess capacity, cost-of-service, rate design. |
| 5/84 | 830470-EI | FL | Florida Industrial Power Users' Group | Florida Power Corp. | Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility. |
| 10/84 | 84-199-U | AR | Arkansas Electric Energy Consumers | Arkansas Power and Light Co. | Cost allocation and rate design. |
| 11/84 | R-842651 | PA | Lehigh Valley Power Committee | Pennsylvania Power & Light Co. | Interruptible rates, excess capacity, and phase-in. |
| 1/85 | 85-65 | ME | Airco Industrial Gases | Central Maine Power Co. | Interruptible rate design. |
| 2/85 | I-840381 | PA | Philadelphia Area Industrial Energy Users' Group | Philadelphia Electric Co. | Load and energy forecast. |
| 3/85 | 9243 | KY | Alcan Aluminum Corp., et al. | Louisville Gas & Electric Co. | Economics of completing fossil generating unit. |
| 3/85 | 3498-U | GA | Attorney General | Georgia Power Co. | Load and energy forecasting, generation planning economics. |
| 3/85 | R-842632 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 5/85 | 84-249 | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Cost-of-service, rate design return multipliers. |
| 5/85 | | City of Santa Clara | Chamber of Commerce | Santa Clara Municipal | Cost-of-service, rate design. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 6/85 | 84-768-E-42T | WV | West Virginia Industrial Intervenors | Monongahela Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 6/85 | E-7 Sub 391 | NC | Carolina Industrials (CIGFUR III) | Duke Power Co. | Cost-of-service, rate design, interruptible rate design. |
| 7/85 | 29046 | NY | Industrial Energy Users Association | Orange and Rockland Utilities | Cost-of-service, rate design. |
| 10/85 | 85-043-U | AR | Arkansas Gas Consumers | Arkla, Inc. | Regulatory policy, gas cost-of-service, rate design. |
| 10/85 | 85-63 | ME | Airco Industrial Gases | Central Maine Power Co. | Feasibility of interruptible rates, avoided cost. |
| 2/85 | ER-8507698 | NJ | Air Products and Chemicals | Jersey Central Power & Light Co. | Rate design. |
| 3/85 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Optimal reserve, prudence, off-system sales guarantee plan. |
| 2/86 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Optimal reserve margins, prudence, off-system sales guarantee plan. |
| 3/86 | 85-299U | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Cost-of-service, rate design, revenue distribution. |
| 3/86 | 85-726-EL-AIR | OH | Industrial Electric Consumers Group | Ohio Power Co. | Cost-of-service, rate design, interruptible rates. |
| 5/86 | 86-081-E-GI | WV | West Virginia Energy Users Group | Monongahela Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 8/86 | E-7 Sub 408 | NC | Carolina Industrial Energy Consumers | Duke Power Co. | Cost-of-service, rate design, interruptible rates. |
| 10/86 | U-17378 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Excess capacity, economic analysis of purchased power. |
| 12/86 | 38063 | IN | Industrial Energy Consumers | Indiana & Michigan Power Co. | Interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 3/87 | EL-86-53-001 EL-86-57-001 | Federal Energy Regulatory Commission (FERC) | Louisiana Public Service Commission Staff | Gulf States Utilities, Southern Co. | Cost/benefit analysis of unit power sales contract. |
| 4/87 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Load forecasting and imprudence damages, River Bend Nuclear unit. |
| 5/87 | 87-023-E-C | WV | Airco Industrial Gases | Monongahela Power Co. | Interruptible rates. |
| 5/87 | 87-072-E-G1 | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims. |
| 5/87 | 86-524-E-SC | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Economic dispatching of pumped storage hydro unit. |
| 5/87 | 9781 | KY | Kentucky Industrial Energy Consumers | Louisville Gas & Electric Co. | Analysis of impact of 1986 Tax Reform Act. |
| 6/87 | 3673-U | GA | Georgia Public Service Commission | Georgia Power Co. | Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning. |
| 6/87 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Phase-in plan for River Bend Nuclear unit. |
| 7/87 | 85-10-22 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Methodology for refunding rate moderation fund. |
| 8/87 | 3673-U | GA | Georgia Public Service Commission | Georgia Power Co. | Test year sales and revenue forecast. |
| 9/87 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Excess capacity, reliability of generating system. |
| 10/87 | R-870651 | PA | Duquesne Industrial Intervenors | Duquesne Light Co. | Interruptible rate, cost-of-service, revenue allocation, rate design. |
| 10/87 | I-860025 | PA | Pennsylvania Industrial Intervenors | | Proposed rules for cogeneration, avoided cost, rate recovery. |
| 10/87 | E-015/ | MN | Taconite | Minnesota Power | Excess capacity, power and |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | GR-87-223 | | Intervenors | & Light Co. | cost-of-service, rate design. |
| 10/87 | 8702-EI | FL | Occidental Chemical Corp. | Florida Power Corp. | Revenue forecasting, weather normalization. |
| 12/87 | 87-07-01 | CT | Connecticut Industrial Energy Consumers | Connecticut Light Power Co. | Excess capacity, nuclear plant phase-in. |
| 3/88 | 10064 | KY | Kentucky Industrial Energy Consumers | Louisville Gas & Electric Co. | Revenue forecast, weather normalization rate treatment of cancelled plant. |
| 3/88 | 87-183-TF | AR | Arkansas Electric Consumers | Arkansas Power & Light Co. | Standby/backup electric rates. |
| 5/88 | 870171C001 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Cogeneration deferral mechanism, modification of energy cost recovery (ECR). |
| 6/88 | 870172C005 | PA | GPU Industrial Intervenors | Pennsylvania Electric Co. | Cogeneration deferral mechanism, modification of energy cost recovery (ECR). |
| 7/88 | 88-171-EL-AIR 88-170-EL-AIR Interim Rate Case | OH | Industrial Energy Consumers | Cleveland Electric/ Toledo Edison | Financial analysis/need for interim rate relief. |
| 7/88 | Appeal of PSC | 19th Judicial Docket U-17282 | Louisiana Public Service Commission Circuit Court of Louisiana | Gulf States Utilities | Load forecasting, imprudence damages. |
| 11/88 | R-880989 | PA | United States Steel | Carnegie Gas | Gas cost-of-service, rate design. |
| 11/88 | 88-171-EL-AIR 88-170-EL-AIR | OH | Industrial Energy Consumers | Cleveland Electric/ Toledo Edison. General Rate Case. | Weather normalization of peak loads, excess capacity, regulatory policy. |
| 3/89 | 870216/283 284/286 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Calculated avoided capacity, recovery of capacity payments. |
| 8/89 | 8555 | TX | Occidental Chemical Corp. | Houston Lighting & Power Co. | Cost-of-service, rate design. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 8/89 | 3840-U | GA | Georgia Public Service Commission | Georgia Power Co. | Revenue forecasting, weather normalization. |
| 9/89 | 2087 | NM | Attorney General of New Mexico | Public Service Co. of New Mexico | Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting. |
| 10/89 | 2262 | NM | New Mexico Industrial Energy Consumers | Public Service Co. of New Mexico | Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost. |
| 11/89 | 38728 | IN | Industrial Consumers for Fair Utility Rates | Indiana Michigan Power Co. | Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates. |
| 1/90 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Jurisdictional cost allocation, O&M expense analysis. |
| 5/90 | 890366 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Non-utility generator cost recovery. |
| 6/90 | R-901609 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Allocation of QF demand charges in the fuel cost, cost-of-service, rate design. |
| 9/90 | 8278 | MD | Maryland Industrial Group | Baltimore Gas & Electric Co. | Cost-of-service, rate design, revenue allocation. |
| 12/90 | U-9346 Rebuttal | MI | Association of Businesses Advocating Tariff Equity | Consumers Power Co. | Demand-side management, environmental externalities. |
| 12/90 | U-17282 Phase IV | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Revenue requirements, jurisdictional allocation. |
| 12/90 | 90-205 | ME | Airco Industrial Gases | Central Maine Power Co. | Investigation into interruptible service and rates. |
| 1/91 | 90-12-03 Interim | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Interim rate relief, financial analysis, class revenue allocation. |
| 5/91 | 90-12-03 Phase II | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Revenue requirements, cost-of-service, rate design, demand-side management. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 8/91 | E-7, SUB SUB 487 | NC | North Carolina Industrial Energy Consumers | Duke Power Co. | Revenue requirements, cost allocation, rate design, demand-side management. |
| 8/91 | 8341 Phase I | MD | Westvaco Corp. | Potomac Edison Co. | Cost allocation, rate design, 1990 Clean Air Act Amendments. |
| 8/91 | 91-372 EL-UNC | OH | Armco Steel Co., L.P. | Cincinnati Gas & Electric Co. | Economic analysis of cogeneration, avoid cost rate. |
| 9/91 | P-910511 P-910512 | PA | Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group | West Penn Power Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 9/91 | 91-231 -E-NC | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 10/91 | 8341 - Phase II | MD | Westvaco Corp. | Potomac Edison Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 10/91 Note: No testimony was prefiled on this. | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Results of comprehensive management audit. |
| 11/91 | U-17949 Subdocket A | LA | Louisiana Public Service Commission Staff | South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co. | Analysis of South Central Bell's restructuring and |
| 12/91 | 91-410- EL-AIR | OH | Armco Steel Co., Air Products & Chemicals, Inc. | Cincinnati Gas & Electric Co. | Rate design, interruptible rates. |
| 12/91 | P-880286 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Evaluation of appropriate avoided capacity costs - QF projects. |
| 1/92 | C-913424 | PA | Duquesne Interruptible Complainants | Duquesne Light Co. | Industrial interruptible rate. |
| 6/92 | 92-02-19 | CT | Connecticut Industrial Energy Consumers | Yankee Gas Co. | Rate design. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 8/92 | 2437 | NM | New Mexico Industrial Intervenors | Public Service Co. of New Mexico | Cost-of-service. |
| 8/92 | R-00922314 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Cost-of-service, rate design, energy cost rate. |
| 9/92 | 39314 | ID | Industrial Consumers for Fair Utility Rates | Indiana Michigan Power Co. | Cost-of-service, rate design, energy cost rate, rate treatment. |
| 10/92 | M-00920312 C-007 | PA | The GPU Industrial Intervenors | Pennsylvania Electric Co. | Cost-of-service, rate design, energy cost rate, rate treatment. |
| 12/92 | U-17949 | LA | Louisiana Public Service Commission Staff | South Central Bell Co. | Management audit. |
| 12/92 | R-00922378 | PA | Armco Advanced Materials Co. The WPP Industrial Intervenors | West Penn Power Co. | Cost-of-service, rate design, energy cost rate, $SO_2$ allowance rate treatment. |
| 1/93 | 8487 | MD | The Maryland Industrial Group | Baltimore Gas & Electric Co. | Electric cost-of-service and rate design, gas rate design (flexible rates). |
| 2/93 | E002/GR-92-1185 | MN | North Star Steel Co. Praxair, Inc. | Northern States Power Co. | Interruptible rates. |
| 4/93 | EC92 21000 ER92-806-000 (Rebuttal) | Federal Energy Regulatory Commission | Louisiana Public Service Commission Staff | Gulf States Utilities/Entergy agreement. | Merger of GSU into Entergy System; impact on system |
| 7/93 | 93-0114-E-C | WV | Airco Gases | Monongahela Power Co. | Interruptible rates. |
| 8/93 | 930759-EG | FL | Florida Industrial Power Users' Group | Generic - Electric Utilities | Cost recovery and allocation of DSM costs. |
| 9/93 | M-009 30406 | PA | Lehigh Valley Power Committee | Pennsylvania Power & Light Co. | Ratemaking treatment of off-system sales revenues. |
| 11/93 | 346 | KY | Kentucky Industrial Utility Customers | Generic - Gas Utilities | Allocation of gas pipeline transition costs - FERC Order 636. |
| 12/93 | U-17735 | LA | Louisiana Public Service Commission Staff | Cajun Electric Power Cooperative | Nuclear plant prudence, forecasting, excess capacity. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 4/94 | E-015/ GR-94-001 | MN | Large Power Intervenors | Minnesota Power Co. | Cost allocation, rate design, rate phase-in plan. |
| 5/94 | U-20178 | LA | Louisiana Public Service Commission | Louisiana Power & Light Co. | Analysis of least cost integrated resource plan and demand-side management program. |
| 7/94 | R-00942986 | PA | Armco, Inc.; West Penn Power Industrial Intervenors | West Penn Power Co. | Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense. |
| 7/94 | 94-0035-E-42T | WV | West Virginia Energy Users Group | Monongahela Power Co. | Cost-of-service, allocation of rate increase, and rate design. |
| 8/94 | EC94 13-000 | Federal Energy Regulatory Commission | Louisiana Public Service Commission | Gulf States Utilities/Entergy | Analysis of extended reserve shutdown units and violation of system agreement by Entergy. |
| 9/94 | R-00943 081 R-00943 081C0001 | PA | Lehigh Valley Power Committee | Pennsylvania Public Utility Commission | Analysis of interruptible rate terms and conditions, availability. |
| 9/94 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Evaluation of appropriate avoided cost rate. |
| 9/94 | U-19904 | LA | Louisiana Public Service Commission | Gulf States Utilities | Revenue requirements. |
| 10/94 | 5258-U | GA | Georgia Public Service Commission | Southern Bell Telephone & Telegraph Co. | Proposals to address competition in telecommunication markets. |
| 11/94 | EC94-7-000 ER94-898-000 | FERC | Louisiana Public Service Commission | El Paso Electric and Central and Southwest | Merger economics, transmission equalization hold harmless proposals. |
| 2/95 | 941-430EG | CO | CF&I Steel, L.P. | Public Service Company of Colorado | Interruptible rates, cost-of-service. |
| 4/95 | R-00943271 | PA | PP&L Industrial Customer Alliance | Pennsylvania Power & Light Co. | Cost-of-service, allocation of rate increase, rate design, interruptible rates. |
| 6/95 | C-00913424 C-00946104 | PA | Duquesne Interruptible Complainants | Duquesne Light Co. | Interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 8/95 | ER95-112 -000 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. | Open Access Transmission Tariffs - Wholesale. |
| 10/95 | U-21485 | LA | Louisiana Public Service Commission | Gulf States Utilities Company | Nuclear decommissioning, revenue requirements, capital structure. |
| 10/95 | ER95-1042 -000 | FERC | Louisiana Public Service Commission | System Energy Resources, Inc. | Nuclear decommissioning, revenue requirements. |
| 10/95 | U-21485 | LA | Louisiana Public Service Commission | Gulf States Utilities Co. | Nuclear decommissioning and cost of debt capital, capital structure. |
| 11/95 | I-940032 | PA | Industrial Energy Consumers of Pennsylvania | State-wide - all utilities | Retail competition issues. |
| 7/96 | U-21496 | LA | Louisiana Public Service Commission | Central Louisiana Electric Co. | Revenue requirement analysis. |
| 7/96 | 8725 | MD | Maryland Industrial Group | Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co. | Ratemaking issues associated with a Merger. |
| 8/96 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Revenue requirements. |
| 9/96 | U-22092 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Decommissioning, weather normalization, capital structure. |
| 2/97 | R-973877 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Co. | Competitive restructuring policy issues, stranded cost, transition charges. |
| 6/97 | Civil Action No. 94-11474 | US Bank-ruptcy Court Middle District of Louisiana | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Confirmation of reorganization plan; analysis of rate paths produced by competing plans. |
| 6/97 | R-973953 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 6/97 | 8738 | MD | Maryland Industrial Group | Generic | Retail competition issues |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 7/97 | R-973954 | PA | PP&L Industrial Customer Alliance | Pennsylvania Power & Light Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 10/97 | 97-204 | KY | Alcan Aluminum Corp. Southwire Co. | Big River Electric Corp. | Analysis of cost of service issues - Big Rivers Restructuring Plan |
| 10/97 | R-974008 | PA | Metropolitan Edison Industrial Users | Metropolitan Edison Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 10/97 | R-974009 | PA | Pennsylvania Electric Industrial Customer | Pennsylvania Electric Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 11/97 | U-22491 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Decommissioning, weather normalization, capital structure. |
| 11/97 | P-971265 | PA | Philadelphia Area Industrial Energy Users Group | Enron Energy Services Power, Inc./ PECO Energy | Analysis of Retail Restructuring Proposal. |
| 12/97 | R-973981 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 12/97 | R-974104 | PA | Duquesne Industrial Intervenors | Duquesne Light Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 3/98 (Allocated Stranded Cost Issues) | U-22092 | LA | Louisiana Public Service Commission | Gulf States Utilities Co. | Retail competition, stranded cost quantification. |
| 3/98 | U-22092 | | Louisiana Public Service Commission | Gulf States Utilities, Inc. | Stranded cost quantification, restructuring issues. |
| 9/98 | U-17735 | | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Revenue requirements analysis, weather normalization. |
| 12/98 | 8794 | MD | Maryland Industrial Group and Millennium Inorganic Chemicals Inc. | Baltimore Gas and Electric Co. | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 12/98 | U-23358 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, weather normalization, Entergy System Agreement. |
| 5/99 (Cross- Answering Testimony) | EC-98-40-000 | FERC | Louisiana Public Service Commission | American Electric Power Co. & Central South West Corp. | Merger issues related to market power mitigation proposals. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 5/99 (Response Testimony) | 98-426 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. | Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services. |
| 6/99 | 98-0452 | WV | West Virginia Energy Users Group | Appalachian Power, Monongahela Power, & Potomac Edison Companies | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 7/99 | 99-03-35 | CT | Connecticut Industrial \Energy Consumers | United Illuminating Company | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 7/99 | Adversary Proceeding No. 98-1065 | U.S. Bankruptcy Court | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Motion to dissolve preliminary injunction. |
| 7/99 | 99-03-06 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 10/99 | U-24182 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, weather normalization, Entergy System Agreement. |
| 12/99 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Ananlysi of Proposed Contract Rates, Market Rates. |
| 03/00 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Evaluation of Cooperative Power Contract Elections |
| 03/00 | 99-1658-EL-ETP | OH | AK Steel Corporation | Cincinnati Gas & Electric Co. | Electric utility restructuring, stranded cost recovery, rate Unbundling. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 08/00 | 98-0452 E-GI | WVA | West Virginia Energy Users Group | Appalachian Power Co. American Electric Co. | Electric utility restructuring rate unbundling. |
| 08/00 | 00-1050 E-T 00-1051-E-T | WVA | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Electric utility restructuring rate unbundling. |
| 10/00 | SOAH 473-00-1020 PUC 2234 | TX | The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities | TXU, Inc. | Electric utility restructuring rate unbundling. |
| 12/00 | U-24993 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, revenue requirements. |
| 12/00 | EL00-66-000 & ER00-2854 EL95-33-002 | LA | Louisiana Public Service Commission | Entergy Services Inc. | Inter-Company System Agreement: Modifications for retail competition, interruptible load. |
| 04/01 | U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Jurisdictional Business Separation - Texas Restructuring Plan |
| 10/01 | 14000-U | GA | Georgia Public Service Commission Adversary Staff | Georgia Power Co. | Test year revenue forecast. |
| 11/01 | U-25687 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning requirements transmission revenues. |
| 11/01 | U-25965 | LA | Louisiana Public Service Commission | Generic . | Independent Transmission Company ("Transco"). RTO rate design. |
| 03/02 | 001148-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design, resource planning and demand side management. |
| 06/02 | U-25965 | LA | Louisiana Public Service Commission | Entergy Gulf States Entergy Louisiana | RTO Issues |
| 07/02 | U-21453 | LA | Louisiana Public Service Commission | SWEPCO, AEP | Jurisdictional Business Sep. - Texas Restructuring Plan. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 08/02 | U-25888 | LA | Louisiana Public Service Commission | Entergy Louisiana, Inc. Entergy Gulf States, Inc. | Modifications to the Inter-Company System Agreement, Production Cost Equalization. |
| 08/02 | EL01-88-000 | FERC | Louisiana Public Service Commission | Entergy Services Inc. and the Entergy Operating Companies | Modifications to the Inter-Company System Agreement, Production Cost Equalization. |
| 11/02 | 02S-315EG | CO | CF&I Steel & Climax Molybdenum Co. | Public Service Co. of Colorado | Fuel Adjustment Clause |
| 01/03 | U-17735 | LA | Louisiana Public Service Commission | Louisiana Coops | Contract Issues |
| 02/03 | 02S-594E | CO | Cripple Creek and Victor Gold Mining Co. | Aquila, Inc. | Revenue requirements, purchased power. |
| 04/03 | U-26527 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Weather normalization, power purchase expenses, System Agreement expenses. |
| 11/03 | ER03-753-000 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Proposed modifications to System Agreement Tariff MSS-4. |
| 11/03 | ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002 | FERC | Louisiana Public Service Commission | Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc. | Evaluation of Wholesale Purchased Power Contracts. |
| 12/03 | U-27136 | LA | Louisiana Public Service Commission | Entergy Louisiana, Inc. | Evaluation of Wholesale Purchased Power Contracts. |
| 01/04 | E-01345-03-0437 | AZ | Kroger Company | Arizona Public Service Co. | Revenue allocation rate design. |
| 02/04 | 00032071 | PA | Duquesne Industrial Intervenors | Duquesne Light Company | Provider of last resort issues. |
| 03/04 | 03A-436E | CO | CF&I Steel, LP and Climax Molybedenum | Public Service Company of Colorado | Purchased Power Adjustment Clause. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 04/04 | 2003-00433<br>2003-00434 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co.<br>Kentucky Utilities Co. | Cost of Service Rate Design |
| 0-6/04 | 03S-539E | CO | Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co. | Aquila, Inc. | Cost of Service, Rate Design<br>Interruptible Rates |
| 06/04 | R-00049255 | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues and transmission service charge. |
| 10/04 | 04S-164E | CO | CF&I Steel Company, Climax Mines | Public Service Company of Colorado | Cost of service, rate design, Interruptible Rates. |
| 03/05 | Case No. 2004-00426<br>Case No. 2004-00421 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Utilities<br>Louisville Gas & Electric Co. | Environmental cost recovery. |
| 06/05 | 050045-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design |
| 07/05 | U-28155 | LA | Louisiana Public Service Commission Staff | Entergy Louisiana, Inc.<br>Entergy Gulf States, Inc. | Independent Coordinator of Transmission – Cost/Benefit |
| 09/05 | Case Nos.<br>05-0402-E-CN<br>05-0750-E-PC | WVA | West Virginia Energy Users Group | Mon Power Co.<br>Potomac Edison Co. | Environmental cost recovery, Securitization, Financing Order |
| 01/06 | 2005-00341 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Power Company | Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism |
| 03/06 | U-22092 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. | Separation of EGSI into Texas and Louisiana Companies. |
| 04/06 | U-25116 | LA | Louisiana Public Service Commission Staff | Entergy Louisiana, Inc. | Transmission Prudence Investigation |
| 06/06 | R-00061346<br>C0001-0005 | PA | Duquesne Industrial Intervenors & IECPA | Duquesne Light Co. | Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues |
| 06/06 | R-00061366<br>R-00061367<br>P-00062213<br>P-00062214 | | Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance | Metropolitan Edison Co.<br>Pennsylvania Electric Co. | Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues |
| 07/06 | U-22092<br>Sub-J | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. | Separation of EGSI into Texas and Louisiana Companies. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 07/06 | Case No. 2006-00130 Case No. 2006-00129 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Utilities Louisville Gas & Electric Co. | Environmental cost recovery. |
| 08/06 | Case No. PUE-2006-00065 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment |
| 09/06 | E-01345A-05-0816 | AZ | Kroger Company | Arizona Public Service Co. | Revenue alllocation, cost of service, rate design. |
| 11/06 | Doc. No. 97-01-15RE02 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power United Illuminating | Rate unbundling issues. |
| 01/07 | Case No. 06-0960-E-42T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Retail Cost of Service Revenue apportionment |
| 03/07 | U-29764 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. Entergy Louisiana, LLC | Implementation of FERC Decision Jurisdictional & Rate Class Allocation |
| 05/07 | Case No. 07-63-EL-UNC | OH | Ohio Energy Group | Ohio Power, Columbus Southern Power | Environmental Surcharge Rate Design |
| 05/07 | R-00049255 Remand | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues and transmission service charge. |
| 06/07 | R-00072155 | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues. |
| 07/07 | Doc. No. 07F-037E | CO | Gateway Canyons LLC | Grand Valley Power Coop. | Distribution Line Cost Allocation |
| 09/07 | Doc. No. 05-UR-103 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Electric Power Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 11/07 | ER07-682-000 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues. |
| 1/08 | Doc. No. 20000-277-ER-07 | WY | Cimarex Energy Company | Rocky Mountain Power (PacifiCorp) | Vintage Pricing, Marginal Cost Pricing Projected Test Year |
| 1/08 | Case No. 07-551 | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules |
| 2/08 | ER07-956 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |
| 2/08 | Doc No. P-00072342 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Default Service Plan issues. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 3/08 | Doc No. E-01933A-05-0650 | AZ | Kroger Company | Tucson Electric Power Co. | Cost of Service, Rate Design |
| 05/08 | 08-0278 E-GI | WV | West Virginia Energy Users Group | Appalachian Power Co. American Electric Power Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 6/08 | Case No. 08-124-EL-ATA | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Recovery of Deferred Fuel Cost |
| 7/08 | Docket No. 07-035-93 | UT | Kroger Company | Rocky Mountain Power Co. | Cost of Service, Rate Design |
| 08/08 | Doc. No. 6680-UR-116 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Power and Light Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 09/08 | Doc. No. 6690-UR-119 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Public Service Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 09/08 | Case No. 08-936-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Competitive Solicitation |
| 09/08 | Case No. 08-935-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Rate Plan |
| 09/08 | Case No. 08-917-EL-SSO 08-918-EL-SSO | OH | Ohio Energy Group | Ohio Power Company Columbus Southern Power Co. | Provider of Last Resort Rate Plan |
| 10/08 | 2008-00251 2008-00252 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. Kentucky Utilities Co. | Cost of Service, Rate Design |
| 11/08 | 08-1511 E-GI | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 11/08 | M-2008-2036188, M-2008-2036197 | PA | Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance | Metropolitan Edison Co. Pennsylvania Electric Co. | Transmission Service Charge |
| 01/09 | ER08-1056 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |
| 01/09 | E-01345A-08-0172 | AZ | Kroger Company | Arizona Public Service Co. | Cost of Service, Rate Design |
| 02/09 | 2008-00409 | KY | Kentucky Industrial Utility Customers, Inc. | East Kentucky Power Cooperative, Inc. | Cost of Service, Rate Design |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 5/09 | PUE-2009 -00018 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Transmission Cost Recovery Rider |
| 5/09 | 09-0177- E-GI | WV | West Virginia Energy Users Group | Appalachian Power Company | Expanded Net Energy Cost "ENEC" Analysis |
| 6/09 | PUE-2009 -00016 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Fuel Cost Recovery Rider |
| 6/09 | PUE-2009 -00038 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Company | Fuel Cost Recovery Rider |
| 7/09 | 080677-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design |
| 8/09 | U-20925 (RRF 2004) | LA | Louisiana Public Service Commission Staff | Entergy Louisiana LLC | Interruptible Rate Refund Settlement |
| 9/09 | 09AL-299E | CO | CF&I Steel Company Climax Molybdenum | Public Service Company of Colorado | Energy Cost Rate issues |
| 9/09 | Doc. No. 05-UR-104 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Electric Power Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 9/09 | Doc. No. 6680-UR-117 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Power and Light Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 10/09 | Docket No. 09-035-23 | UT | Kroger Company | Rocky Mountain Power Co. | Cost of Service, Allocation of Rev Increase |
| 10/09 | 09AL-299E | CO | CF&I Steel Company Climax Molybdenum | Public Service Company of Colorado | Cost of Service, Rate Design |
| 11/09 | PUE-2009 -00019 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Cost of Service, Rate Design |
| 11/09 | 09-1485 E-P | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 12/09 | Case No. 09-906-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Rate Plan |
| 12/09 | ER09-1224 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |
| 12/09 | Case No. PUE-2009-00030 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Allocation of Rev Increase, Rate Design |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of August 2010**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 2/10 | Docket No. 09-035-23 | UT | Kroger Company | Rocky Mountain Power Co. | Rate Design |
| 3/10 | Case No. 09-1352-E-42T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Retail Cost of Service Revenue apportionment |
| 3/10 | E015/ GR-09-1151 | MN | Large Power Intervenors | Minnesota Power Co. | Cost of Service, rate design |
| 4/10 | EL09-61 | FERC | Louisiana Public Service Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | System Agreement Issues Related to off-system sales |
| 4/10 | 2009-00459 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Power Company | Cost of service, rate design, transmission expenses. |
| 4/10 | 2009-00548 2009-00549 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. Kentucky Utilities Co. | Cost of Service, Rate Design |
| 7/10 | R-2010-2161575 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Company | Cost of Service, Rate Design |

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF:**

| | | |
|---|---|---|
| **GENERAL ADJUSTMENT OF ELECTRIC** | ) | |
| **RATES OF EAST KENTUCKY POWER** | ) | **CASE NO.** |
| **COOPERATIVE, INC.** | ) | **2010-000167** |

**EXHIBIT ___(SJB-2)**

**OF**

**STEPHEN J. BARON**

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

**12 Months Ended**
**December 31, 2011**

| Description | Ref | Name | Allocation Vector | Total System | Rate E | Rate B | Rate C |
|---|---|---|---|---|---|---|---|
| **Plant in Service** | | | | | | | |
| **Power Production Plant** | | | | | | | |
| Production Demand | TPIS | PLPDMD | 6CP | $ 2,668,494,777 | $ 2,286,502,704 | $ 128,920,196 | $ 42,576,022 |
| Production Energy | TPIS | PLPENG | PENG | $ 1,637 | $ 1,181 | $ 99 | $ 33 |
| Production - Steam Direct | TPIS | PLPSTM | STMD | $ 17,789,089 | $ - | $ - | $ - |
| Total Power Production Plant | | PLPT | | $ 2,686,285,503 | $ 2,286,503,886 | $ 128,920,295 | $ 42,576,056 |
| **Transmission Plant** | TPIS | PLTRN | 12CP | $ 478,022,950 | $ 397,513,309 | $ 24,622,275 | $ 8,153,286 |
| **Distribution Substation** | TPIS | PLDST | SUBA | $ 177,535,433 | $ 175,739,683 | $ - | $ - |
| **Distribution Meters** | TPIS | PLDMC | Cust05 | $ 4,863,364 | $ 4,847,785 | $ - | $ - |
| Total | | PLT | | $ 3,346,707,251 | $ 2,864,604,662 | $ 153,542,569 | $ 50,729,342 |
| **Net Utility Plant** | | | | | | | |
| **Power Production Plant** | | | | | | | |
| Production Demand | NTPLANT | NTPDMD | 6CP | $ 2,343,355,947 | $ 2,007,907,138 | $ 113,212,104 | $ 37,388,409 |
| Production Energy | NTPLANT | NTPENG | PENG | $ 1,637 | $ 1,181 | $ 99 | $ 33 |
| Production - Steam Direct | NTPLANT | NTPSTM | STMD | $ 14,405,737 | $ - | $ - | $ - |
| Total Power Production Plant | | NTPT | | $ 2,357,763,321 | $ 2,007,908,319 | $ 113,212,203 | $ 37,388,443 |
| **Transmission Plant** | NTPLANT | NTTRN | 12CP | $ 364,951,525 | $ 303,485,614 | $ 18,798,128 | $ 6,224,710 |
| **Distribution Substation** | NTPLANT | NTDST | SUBA | $ 129,320,466 | $ 128,012,405 | $ - | $ - |
| **Distribution Meters** | NTPLANT | NTDMC | Cust05 | $ 3,206,982 | $ 3,196,709 | $ - | $ - |
| Total | | NTPLT | | $ 2,855,242,294 | $ 2,442,603,046 | $ 132,010,331 | $ 43,613,153 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | $ 47,003,929 | $ 163,491,926 | $ - | $ - |
| Production Energy | TPIS | PLPENG | PENG | $ 35 | $ 105 | $ 155 | $ 28 |
| Production - Steam Direct | TPIS | PLPSTM | STMD | $ - | $ - | $ - | $ 17,789,089 |
| Total Power Production Plant | | PLPT | | $ 47,003,963 | $ 163,492,031 | $ 155 | $ 17,789,117 |
| **Transmission Plant** | TPIS | PLTRN | 12CP | $ 8,965,367 | $ 31,183,884 | $ 7,584,830 | $ - |
| **Distribution Substation** | TPIS | PLDST | SUBA | $ 1,795,750 | $ - | $ - | $ - |
| **Distribution Meters** | TPIS | PLDMC | Cust05 | $ 15,579 | $ - | $ - | $ - |
| Total | | PLT | | $ 57,780,660 | $ 194,675,915 | $ 7,584,985 | $ 17,789,117 |
| **Net Utility Plant** | | | | | | | |
| **Power Production Plant** | | | | | | | |
| Production Demand | NTPLANT | NTPDMD | 6CP | $ 41,276,804 | $ 143,571,492 | $ - | $ - |
| Production Energy | NTPLANT | NTPENG | PENG | $ 35 | $ 105 | $ 155 | $ 28 |
| Production - Steam Direct | NTPLANT | NTPSTM | STMD | $ - | $ - | $ - | $ 14,405,737 |
| Total Power Production Plant | | NTPT | | $ 41,276,839 | $ 143,571,597 | $ 155 | $ 14,405,765 |
| **Transmission Plant** | NTPLANT | NTTRN | 12CP | $ 6,844,701 | $ 23,807,656 | $ 5,790,716 | $ - |
| **Distribution Substation** | NTPLANT | NTDST | SUBA | $ 1,308,062 | $ - | $ - | $ - |
| **Distribution Meters** | NTPLANT | NTDMC | Cust05 | $ 10,273 | $ - | $ - | $ - |
| Total | | NTPLT | | $ 49,439,875 | $ 167,379,253 | $ 5,790,872 | $ 14,405,765 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | $ 2,435,346,878 | $ 2,086,729,669 | $ 117,656,365 | $ 38,856,131 |
| Production Energy | RB | RBPENG | PENG | $ 5,810,059 | $ 4,192,617 | $ 351,108 | $ 118,498 |
| Production - Steam Direct | RB | RBPSTM | STMD | $ 14,947,573 | $ - | $ - | $ - |
| Total Power Production Plant | | RBPT | | $ 2,456,104,509 | $ 2,090,922,286 | $ 118,007,473 | $ 38,974,629 |
| **Transmission Plant** | RB | RBTRN | 12CP | $ 384,802,948 | $ 319,993,617 | $ 19,820,647 | $ 6,563,301 |
| **Distribution Substation** | RB | RBDST | SUBA | $ 135,096,997 | $ 133,730,506 | $ - | $ - |
| **Distribution Meters** | RB | RBDMC | Cust05 | $ 3,409,156 | $ 3,398,235 | $ - | $ - |
| Total | | RBPLT | | $ 2,979,413,610 | $ 2,548,044,644 | $ 137,828,120 | $ 45,537,930 |

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

12 Months Ended
December 31, 2011

| 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 | $ | 42,897,169 | $ | 149,207,544 | $ | - | $ | - |
| Production Energy | RB | RBPENG | PENG | $ | 123,015 | $ | 372,694 | $ | 551,369 | $ | 100,758 |
| Production - Steam Direct | RB | RBPSTM | STMD | $ | - | $ | - | $ | - | $ | 14,947,573 |
| Total Power Production Plant | | RBPT | | $ | 43,020,184 | $ | 149,580,238 | $ | 551,369 | $ | 15,048,330 |
| **Transmission Plant** | RB | RBTRN | 12CP | $ | 7,217,016 | $ | 25,102,666 | $ | 6,105,700 | $ | - |
| **Distribution Substation** | RB | RBDST | SUBA | $ | 1,366,490 | $ | - | $ | - | $ | - |
| **Distribution Meters** | RB | RBDMC | Cust05 | $ | 10,921 | $ | - | $ | - | $ | - |
| Total | | RBPLT | | $ | 51,614,612 | $ | 174,682,903 | $ | 6,657,070 | $ | 15,048,330 |

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

12 Months Ended
December 31, 2011

| 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 | $ 92,062,756 | $ 78,884,075 | $ 4,447,732 | $ 1,468,868 |
| Production Energy | TOM | OMPENG | PENG | $ 75,713,464 | $ 54,635,859 | $ 4,575,444 | $ 1,544,201 |
| Production - Steam Direct | TOM | OMPSTM | STMD | $ 42,467 | $ - | $ - | $ - |
| Total Power Production Plant | | OMPT | | $ 167,818,687 | $ 133,519,934 | $ 9,023,175 | $ 3,013,069 |
| **Transmission Plant** | TOM | OMTRN | 12CP | $ 43,472,163 | $ 36,150,489 | $ 2,239,189 | $ 741,473 |
| **Distribution Substation** | TOM | OMDST | SUBA | $ 3,375,813 | $ 3,341,667 | $ - | $ - |
| **Distribution Meters** | TOM | OMDMC | Cust05 | $ 443,938 | $ 442,516 | $ - | $ - |
| Total | | OMPLT | | $ 215,110,601 | $ 173,454,605 | $ 11,262,364 | $ 3,754,542 |
| **Labor Expenses** | | | | | | | |
| **Power Production Plant** | | | | | | | |
| Production Demand | TLB | LBPDMD | 6CP | $ 26,637,449 | $ 22,824,328 | $ 1,286,907 | $ 425,002 |
| Production Energy | TLB | LBPENG | PENG | $ 16,914,749 | $ 12,205,911 | $ 1,022,176 | $ 344,982 |
| Production - Steam Direct | TLB | LBPSTM | STMD | $ 5,996 | $ - | $ - | $ - |
| Total Power Production Plant | | LBPT | | $ 43,558,194 | $ 35,030,239 | $ 2,309,083 | $ 769,984 |
| **Transmission Plant** | TLB | LBTRN | 12CP | $ 7,445,197 | $ 6,191,261 | $ 383,491 | $ 126,987 |
| **Distribution Substation** | TLB | LBDST | SUBA | $ 996,305 | $ 986,228 | $ - | $ - |
| **Distribution Meters** | TLB | LBDMC | Cust05 | $ 76,031 | $ 75,787 | $ - | $ - |
| Total | | LBPLT | | $ 52,075,727 | $ 42,283,515 | $ 2,692,575 | $ 896,972 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | $ 1,621,630 | $ 5,640,452 | $ - | $ - |
| Production Energy | TOM | OMPENG | PENG | $ 1,603,061 | $ 4,856,740 | $ 7,185,140 | $ 1,313,018 |
| Production - Steam Direct | TOM | OMPSTM | STMD | $ - | $ - | $ - | $ 42,467 |
| Total Power Production Plant | | OMPT | | $ 3,224,691 | $ 10,497,193 | $ 7,185,140 | $ 1,355,485 |
| **Transmission Plant** | TOM | OMTRN | 12CP | $ 815,325 | $ 2,835,912 | $ 689,776 | $ - |
| **Distribution Substation** | TOM | OMDST | SUBA | $ 34,146 | $ - | $ - | $ - |
| **Distribution Meters** | TOM | OMDMC | Cust05 | $ 1,422 | $ - | $ - | $ - |
| Total | | OMPLT | | $ 4,075,584 | $ 13,333,104 | $ 7,874,916 | $ 1,355,485 |
| **Labor Expenses** | | | | | | | |
| **Power Production Plant** | | | | | | | |
| Production Demand | TLB | LBPDMD | 6CP | $ 469,203 | $ 1,632,009 | $ - | $ - |
| Production Energy | TLB | LBPENG | PENG | $ 358,132 | $ 1,085,019 | $ 1,605,195 | $ 293,335 |
| Production - Steam Direct | TLB | LBPSTM | STMD | $ - | $ - | $ - | $ 5,996 |
| Total Power Production Plant | | LBPT | | $ 827,334 | $ 2,717,028 | $ 1,605,195 | $ 299,331 |
| **Transmission Plant** | TLB | LBTRN | 12CP | $ 139,635 | $ 485,688 | $ 118,134 | $ - |
| **Distribution Substation** | TLB | LBDST | SUBA | $ 10,078 | $ - | $ - | $ - |
| **Distribution Meters** | TLB | LBDMC | Cust05 | $ 244 | $ - | $ - | $ - |
| Total | | LBPLT | | $ 977,291 | $ 3,202,716 | $ 1,723,328 | $ 299,331 |

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

12 Months Ended
December 31, 2011

| Description | Ref | Name | Allocation Vector | Total System | Rate E | Rate B | Rate C |
|---|---|---|---|---|---|---|---|
| Depreciation Expenses | | | | | | | |
| **Power Production Plant** | | | | | | | |
| Production Demand | TDEPR | DPPDMD | 6CP | $ 46,797,943 | $ 40,098,869 | $ 2,260,900 | $ 746,664 |
| Production Energy | TDEPR | DPPENG | PENG | $ - | $ - | $ - | $ - |
| Production - Steam Direct | TDEPR | DPPSTM | STMD | $ 312,226 | $ - | $ - | $ - |
| Total Power Production Plant | | DPPT | | $ 47,110,169 | $ 40,098,869 | $ 2,260,900 | $ 746,664 |
| **Transmission Plant** | TDEPR | DPTRN | 12CP | $ 7,127,756 | $ 5,927,285 | $ 367,140 | $ 121,573 |
| **Distribution Substation** | TDEPR | DPDST | SUBA | $ 6,313,051 | $ 6,249,195 | $ - | $ - |
| **Distribution Meters** | TDEPR | DPDMC | Cust05 | $ 72,794 | $ 72,561 | $ - | $ - |
| Total | | DPPLT | | $ 60,623,770 | $ 52,347,909 | $ 2,628,041 | $ 868,237 |
| Property and Other Taxes | | | | | | | |
| **Power Production Plant** | | | | | | | |
| Production Demand | PTAX | PRPDMD | 6CP | $ 649 | $ 556 | $ 31 | $ 10 |
| Production Energy | PTAX | PRPENG | PENG | $ 0 | $ 0 | $ 0 | $ 0 |
| Production - Steam Direct | PTAX | PRPSTM | STMD | $ 4 | $ - | $ - | $ - |
| Total Power Production Plant | | PRPT | | $ 653 | $ 556 | $ 31 | $ 10 |
| **Transmission Plant** | PTAX | PRTRN | 12CP | $ 107 | $ 89 | $ 6 | $ 2 |
| **Distribution Substation** | PTAX | PRDST | SUBA | $ 39 | $ 38 | $ - | $ - |
| **Distribution Meters** | PTAX | PRDMC | Cust05 | $ 1 | $ 1 | $ - | $ - |
| Total | | PRPLT | | $ 800 | $ 685 | $ 37 | $ 12 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | $ 824,318 | $ 2,867,192 | $ - | $ - |
| Production Energy | TDEPR | DPPENG | PENG | $ - | $ - | $ - | $ - |
| Production - Steam Direct | TDEPR | DPPSTM | STMD | $ - | $ - | $ - | $ 312,226 |
| Total Power Production Plant | | DPPT | | $ 824,318 | $ 2,867,192 | $ - | $ 312,226 |
| **Transmission Plant** | TDEPR | DPTRN | 12CP | $ 133,682 | $ 464,980 | $ 113,097 | $ - |
| **Distribution Substation** | TDEPR | DPDST | SUBA | $ 63,856 | $ - | $ - | $ - |
| **Distribution Meters** | TDEPR | DPDMC | Cust05 | $ 233 | $ - | $ - | $ - |
| Total | | DPPLT | | $ 1,022,088 | $ 3,332,172 | $ 113,097 | $ 312,226 |
| **Property and Other Taxes** | | | | | | | |
| **Power Production Plant** | | | | | | | |
| Production Demand | PTAX | PRPDMD | 6CP | $ 11 | $ 40 | $ - | $ - |
| Production Energy | PTAX | PRPENG | PENG | $ 0 | $ 0 | $ 0 | $ 0 |
| Production - Steam Direct | PTAX | PRPSTM | STMD | $ - | $ - | $ - | $ 4 |
| Total Power Production Plant | | PRPT | | $ 11 | $ 40 | $ 0 | $ 4 |
| **Transmission Plant** | PTAX | PRTRN | 12CP | $ 2 | $ 7 | $ 2 | $ - |
| **Distribution Substation** | PTAX | PRDST | SUBA | $ 0 | $ - | $ - | $ - |
| **Distribution Meters** | PTAX | PRDMC | Cust05 | $ 0 | $ - | $ - | $ - |
| Total | | PRPLT | | $ 14 | $ 47 | $ 2 | $ 4 |

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

**12 Months Ended**
**December 31, 2011**

| Description | Ref | Name | Allocation Vector | | Total System | | Rate E | | Rate B | | Rate C |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Interest Expenses** | | | | | | | | | | | |
| **Power Production Plant** | | | | | | | | | | | |
| Production Demand | INTLTD | INPDMD | 6CP | $ | 91,205,137 | $ | 78,149,223 | $ | 4,406,298 | $ | 1,455,184 |
| Production Energy | INTLTD | INPENG | PENG | $ | 48 | $ | 35 | $ | 3 | $ | 1 |
| Production - Steam Direct | INTLTD | INPSTM | STMD | $ | 572,043 | $ | - | $ | - | $ | - |
| Total Power Production Plant | | INPT | | $ | 91,777,229 | $ | 78,149,258 | $ | 4,406,301 | $ | 1,455,185 |
| **Transmission Plant** | INTLTD | INTRN | 12CP | $ | 15,031,692 | $ | 12,500,022 | $ | 774,261 | $ | 256,385 |
| **Distribution Substation** | INTLTD | INDST | SUBA | $ | 5,418,038 | $ | 5,363,235 | $ | - | $ | - |
| **Distribution Meters** | INTLTD | INDMC | Cust05 | $ | 152,967 | $ | 152,477 | $ | - | $ | - |
| Total | | INPLT | | $ | 112,379,925 | $ | 96,164,991 | $ | 5,180,562 | $ | 1,711,570 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | $ | 1,606,524 | $ 5,587,908 | $ - | $ - |
| Production Energy | INTLTD | INPENG | PENG | $ | 1 | $ 3 | $ 5 | $ 1 |
| Production - Steam Direct | INTLTD | INPSTM | STMD | $ | - | $ - | $ - | $ 572,043 |
| Total Power Production Plant | | INPT | | $ | 1,606,525 | $ 5,587,911 | $ 5 | $ 572,044 |
| **Transmission Plant** | INTLTD | INTRN | 12CP | $ | 281,921 | $ 980,594 | $ 238,509 | $ - |
| **Distribution Substation** | INTLTD | INDST | SUBA | $ | 54,803 | $ - | $ - | $ - |
| **Distribution Meters** | INTLTD | INDMC | Cust05 | $ | 490 | $ - | $ - | $ - |
| Total | | INPLT | | $ | 1,943,738 | $ 6,568,505 | $ 238,514 | $ 572,044 |

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

12 Months Ended
December 31, 2011

| 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 | $ 937,679,954 | $ 771,730,098 | $ 56,378,640 | $ 18,785,745 |
| Off System Sales Revenue | | | Energy | $ 4,077,873 | $ 3,208,401 | $ 268,685 | $ 90,681 |
| Wheeling Revenue | | LSDPR | RBTRN | $ 2,538,793 | $ 2,111,204 | $ 130,770 | $ 43,302 |
| Other Operating Revenue | | OTHREV | RBPLT | $ 2,207,169 | $ 1,887,608 | $ 102,104 | $ 33,735 |
| Total Operating Revenues | | TOR | | $ 946,503,789 | $ 778,937,312 | $ 56,880,199 | $ 18,953,463 |
| | | | | $ 8,823,835 | | | |
| **Operating Expenses** | | | | $ 12,278,338 | | | |
| Operation and Maintenance Expenses | | | | $ 215,110,601 | $ 173,454,605 | $ 11,262,364 | $ 3,754,542 |
| Depreciation and Amortization Expenses | | | | 60,623,770 | 52,347,909 | 2,628,041 | 868,237 |
| Property and Other Taxes | | | NPT | 800 | 685 | 37 | 12 |
| Total Operating Expenses | | TOE | | $ 275,735,171 | $ 225,803,199 | $ 13,890,441 | $ 4,622,792 |
| Utility Operating Margin | | | | $ 670,768,618 | $ 553,134,112 | $ 42,989,758 | $ 14,330,671 |
| **Non-Operating Items** | | | | | | | |
| Interest Income | | | RBPLT | $ 3,360,147 | $ 2,873,654 | $ 155,441 | $ 51,357 |
| Other Non-Operating Income | | | RBPLT | $ (67,400) | $ (57,642) | $ (3,118) | $ (1,030) |
| Other Credits | | | RBPLT | $ 161,756 | $ 138,336 | $ 7,483 | $ 2,472 |
| Interest on Long Term Debt | | | | $ (112,379,925) | $ (96,164,991) | $ (5,180,562) | $ (1,711,570) |
| Other Interest Expense | | | RBPLT | $ - | $ - | $ - | $ - |
| Other Deductions | | | RBPLT | $ - | $ - | $ - | $ - |
| Total Non-Operating Items | | | | $ (108,925,422) | $ (93,210,642) | $ (5,020,756) | $ (1,658,771) |
| Net Utility Operating Margin | | TOM | | $ 561,843,196 | $ 459,923,470 | $ 37,969,001 | $ 12,671,901 |
| Net Cost Rate Base | | | | $ 2,979,413,610 | $ 2,548,044,644 | $ 137,828,120 | $ 45,537,930 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | $ 19,002,098 | $ 48,697,556 | $ 9,009,512 | $ 14,076,304 |
| Off System Sales Revenue | | | Energy | $ 94,137 | $ 285,204 | $ 53,660 | $ 77,105 |
| Wheeling Revenue | | LSDPR | RBTRN | $ 47,615 | $ 165,618 | $ 40,283 | $ - |
| Other Operating Revenue | | OTHREV | RBPLT | $ 38,236 | $ 129,406 | $ 4,932 | $ 11,148 |
| Total Operating Revenues | | TOR | | $ 19,182,087 | $ 49,277,785 | $ 9,108,387 | $ 14,164,557 |
| **Operating Expenses** | | | | | | | |
| Operation and Maintenance Expenses | | | | $ 4,075,584 | $ 13,333,104 | $ 7,874,916 | $ 1,355,485 |
| Depreciation and Amortization Expenses | | | | 1,022,088 | 3,332,172 | 113,097 | 312,226 |
| Property and Other Taxes | | | NPT | 14 | 47 | 2 | 4 |
| Total Operating Expenses | | TOE | | $ 5,097,686 | $ 16,665,323 | $ 7,988,015 | $ 1,667,715 |
| Utility Operating Margin | | | | $ 14,084,401 | $ 32,612,462 | $ 1,120,372 | $ 12,496,841 |
| **Non-Operating Items** | | | | | | | |
| Interest Income | | | RBPLT | $ 58,210 | $ 197,005 | $ 7,508 | $ 16,971 |
| Other Non-Operating Income | | | RBPLT | $ (1,168) | $ (3,952) | $ (151) | $ (340) |
| Other Credits | | | RBPLT | $ 2,802 | $ 9,484 | $ 361 | $ 817 |
| Interest on Long Term Debt | | | | $ (1,943,738) | $ (6,568,505) | $ (238,514) | $ (572,044) |
| Other Interest Expense | | | RBPLT | $ - | $ - | $ - | $ - |
| Other Deductions | | | RBPLT | $ - | $ - | $ - | $ - |
| Total Non-Operating Items | | | | $ (1,883,893) | $ (6,365,968) | $ (230,795) | $ (554,596) |
| Net Utility Operating Margin | | TOM | | $ 12,200,508 | $ 26,246,494 | $ 889,577 | $ 11,942,245 |
| Net Cost Rate Base | | | | $ 51,614,612 | $ 174,682,903 | $ 6,657,070 | $ 15,048,330 |

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

12 Months Ended
December 31, 2011

| Description | Ref | Name | Allocation Vector | Total System | Rate E | Rate B | Rate C |
|---|---|---|---|---|---|---|---|
| **Cost of Service Summary -- Pro-Forma** | | | | | | | |
| **Operating Revenues** | | | | | | | |
| Total Operating Revenue | | | | $ 946,503,789 | $ 778,937,312 | $ 56,880,199 | $ 18,953,463 |
| Pro-Forma Adjustments: | | | | | | | |
| To Remove Base Fuel Revenue | | | BSFL | $ 499,738,400 | $ 398,428,491 | $ 33,366,130 | $ 11,260,990 |
| To Remove FAC Revenue | | | FACA | (41,688,649) | (38,965,806) | (3,263,166) | (1,101,311) |
| To Remove Environmental Surcharge Revenue | | ESR | | 102,349,021 | 84,579,700 | 6,178,959 | 2,058,871 |
| To Adjust Off-System Sales Environmental Sur. Rev. | | | RBPLT | 491,972 | 420,743 | 22,759 | 7,519 |
| Total Pro-Forma Operating Revenue | | | | $ 385,613,045 | $ 334,474,184 | $ 20,575,517 | $ 6,727,393 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | | | | $ 19,182,087 | $ 49,277,785 | $ 9,108,387 | $ 14,164,557 |
| Pro-Forma Adjustments: | | | | | | | |
| To Remove Base Fuel Revenue | | | BSFL | $ 11,690,221 | $ 35,417,468 | $ - | $ 9,575,100 |
| To Remove FAC Revenue | | | FACA | (1,143,289) | (3,463,784) | 7,185,140 | (936,433) |
| To Remove Environmental Surcharge Revenue | | ESR | | 2,082,583 | 5,337,131 | 569,049 | 1,542,728 |
| To Adjust Off-System Sales Environmental Sur. Rev. | | | RBPLT | 8,523 | 28,844 | 1,099 | 2,485 |
| Total Pro-Forma Operating Revenue | | | | $ 6,544,050 | $ 11,958,126 | $ 1,353,098 | $ 3,980,677 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | | | | $ 215,110,601 | $ 173,454,605 | $ 11,262,364 | $ 3,754,542 |
| Depreciation and Amortization Expenses | | | | 60,623,770 | 52,347,909 | 2,628,041 | 868,237 |
| Property and Other Taxes | | | NPT | 800 | 685 | 37 | 12 |
| Adjustments to Operating Expenses: | | | | | | | |
| To Remove Fuel Expense Recoverable Through FAC | | | FACAL | $ (7,185,140) | $ - | $ - | $ - |
| To Reflect Avoided Costs of Interruptible Service | | | | $ (9,324,000) | | | |
| Reallocation of Avoided Cost Savings | | | 6CP | $ 9,324,000 | $ 7,989,280 | $ 450,461 | $ 148,765 |
| To Reflect Avoided Fuel Costs of Interruption | | | | $ (3,547,314) | | | |
| Reallocation of Avoided Fuel Cost | | | PENGA | $ 3,547,314 | $ 2,828,182 | $ 236,844 | $ 79,934 |
| Reallocate Purchased Power - Remove on PENG | | | PPPENG | $ (42,997,833) | $ (28,552,533) | $ (2,391,113) | $ (806,995) |
| Reallocate Purchased Power - Allocate On-Peak/Off-Peak | | | PPTOU | $ 42,997,833 | $ 29,029,232 | $ 2,337,736 | $ 782,835 |
| Reallocate Fuel Expense - Remove on PENGA | | | PENGA | $ (445,953,276) | $ (355,547,004) | $ (29,775,049) | $ (10,049,008) |
| Reallocate Fuel Expense - Allocate on Monthly Energy | | | PENG_MON | $ 445,953,276 | $ 355,322,335 | $ 29,859,352 | $ 10,073,954 |
| Total Expense Adjustments | | | | (7,185,140) | 11,069,492 | 718,231 | 229,485 |
| Total Operating Expenses | | TOE | | $ 268,550,031 | $ 236,872,691 | $ 14,608,673 | $ 4,852,276 |
| Utility Operating Margins -- Pro-Forma | | | | $ 117,063,014 | $ 97,601,493 | $ 5,966,844 | $ 1,875,117 |
| **Non-Operating Items** | | | | | | | |
| Sum of Non-Operating Items | | | | $ (108,925,422) | $ (93,210,642) | $ (5,020,756) | $ (1,658,771) |
| Adjustment To Remove Interest Exp. Recoverable Through ESR | | | 6CP | $ - | $ - | $ - | $ - |
| Total Non-Operating Items | | | | $ (108,925,422) | $ (93,210,642) | $ (5,020,756) | $ (1,658,771) |
| Net Utility Operating Margin | | | | $ 8,137,592 | $ 4,390,851 | $ 946,088 | $ 216,346 |
| **Net Cost Rate Base** | | | | $ 2,979,413,610 | $ 2,548,044,644 | $ 137,828,120 | $ 45,537,930 |
| **Return on Rate Base -- Utility Operating Margin Divided by Rate Base** | | | | 3.93% | 3.83% | 4.33% | 4.12% |
| **Dollar Subsidy** | | | | $ (0) | $ (2,512,766) | $ 551,492 | $ 85,903 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | | | | $ 4,075,584 | $ 13,333,104 | $ 7,874,916 | $ 1,355,485 |
| Depreciation and Amortization Expenses | | | | 1,022,088 | 3,332,172 | 113,097 | 312,226 |
| Property and Other Taxes | | | NPT | 14 | 47 | 2 | 4 |
| Adjustments to Operating Expenses: | | | | | | | |
| To Remove Fuel Expense Recoverable Through FAC | | | FACAL | $ - | $ - | $ (7,185,140) | $ - |
| To Reflect Avoided Costs of Interruptible Service | | | | | $ (9,324,000) | | |
| Reallocation of Avoided Cost Savings | | | 6CP | $ 164,237 | $ 571,258 | $ - | $ - |
| To Reflect Avoided Fuel Costs of Interruption | | | | | $ (3,547,314) | | |
| Reallocation of Avoided Fuel Cost | | | PENGA | $ 82,981 | $ 251,405 | $ - | $ 67,967 |
| Reallocate Purchased Power - Remove on PENG | | | PPPENG | $ (837,755) | $ (2,538,118) | $ (7,185,140) | $ (686,179) |
| Reallocate Purchased Power - Allocate On-Peak/Off-Peak | | | PPTOU | $ 816,424 | $ 2,179,566 | $ 7,185,140 | $ 666,901 |
| Reallocate Fuel Expense - Remove on PENGA | | | PENGA | $ (10,432,042) | $ (31,605,608) | $ - | $ (8,544,565) |
| Reallocate Fuel Expense - Allocate on Monthly Energy | | | PENG_MON | $ 10,454,729 | $ 31,688,575 | $ - | $ 8,554,330 |
| Total Expense Adjustments | | | | 248,574 | (12,324,235) | (7,185,140) | 58,454 |
| Total Operating Expenses | | TOE | | $ 5,346,260 | $ 4,341,088 | $ 802,875 | $ 1,726,169 |
| Utility Operating Margins -- Pro-Forma | | | | $ 1,197,790 | $ 7,617,038 | $ 550,224 | $ 2,254,508 |
| **Non-Operating Items** | | | | | | | |
| Sum of Non-Operating Items | | | | $ (1,883,893) | $ (6,365,968) | $ (230,795) | $ (554,596) |
| Adjustment To Remove Interest Exp. Recoverable Through ESR | | | 6CP | $ - | $ - | $ - | $ - |
| Total Non-Operating Items | | | | $ (1,883,893) | $ (6,365,968) | $ (230,795) | $ (554,596) |
| Net Utility Operating Margin | | | | $ (686,103) | $ 1,251,070 | $ 319,428 | $ 1,699,911 |
| **Net Cost Rate Base** | | | | $ 51,614,612 | $ 174,682,903 | $ 6,657,070 | $ 15,048,330 |
| **Return on Rate Base -- Utility Operating Margin Divided by Rate Base** | | | | **2.32%** | **4.36%** | **8.27%** | **14.98%** |
| **Dollar Subsidy** | | | | $ (830,180) | $ 753,638 | $ 288,663 | $ 1,663,249 |

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

**12 Months Ended**
**December 31, 2011**

| Description | Ref | Name | Allocation Vector | Total System | Rate E | Rate B | Rate C |
|---|---|---|---|---|---|---|---|
| **Cost of Service Summary -- Pro-Forma (EKPC Proposed Increase)** | | | | | | | |
| **Operating Revenues** | | | | | | | |
| Total Operating Revenue | | | | $ 385,613,045 | $ 334,474,184 | $ 20,575,517 | $ 6,727,393 |
| Pro-Forma Adjustments:<br>To Reflect Proposed Increase | | | | $ 49,377,447 | $ 40,523,082 | $ 2,979,952 | $ 993,619 |
| Total Pro-Forma Operating Revenue | | | | $ 434,990,492 | $ 374,997,266 | $ 23,555,469 | $ 7,721,012 |
| **Operating Expenses** | | | | | | | |
| Total Operating Expenses | | | | $ 268,550,031 | $ 236,872,691 | $ 14,608,673 | $ 4,852,276 |
| **Utility Operating Margins -- Pro-Formed for Phase I Increase** | | | | $ 166,440,461 | $ 138,124,575 | $ 8,946,796 | $ 2,868,736 |
| **Net Cost Rate Base** | | | | $ 2,979,413,610 | $ 2,548,044,644 | $ 137,828,120 | $ 45,537,930 |
| **Rate of Return** | | | | 5.59% | 5.42% | 6.49% | 6.30% |
| **Dollar Subsidy** | | | | $ (0) | $ (4,218,107) | $ 1,247,236 | $ 324,828 |

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

**12 Months Ended**
**December 31, 2011**

| Description | Ref | Name | Allocation Vector | Rate G | Large Special Contract | Special Contract Pumping Stations | Steam Service |
|---|---|---|---|---|---|---|---|
| **Cost of Service Summary -- Pro-Forma (EKPC Proposed Increase)** | | | | | | | |
| **Operating Revenues** | | | | | | | |
| Total Operating Revenue | | | | $ 6,544,050 | $ 11,958,126 | $ 1,353,098 | $ 3,980,677 |
| Pro-Forma Adjustments: To Reflect Proposed Increase | | | | $ 1,006,664 | $ 3,121,617 | $ - | $ 752,513 |
| Total Pro-Forma Operating Revenue | | | | $ 7,550,714 | $ 15,079,743 | $ 1,353,098 | $ 4,733,190 |
| **Operating Expenses** | | | | | | | |
| Total Operating Expenses | | | | $ 5,346,260 | $ 4,341,088 | $ 802,875 | $ 1,726,169 |
| **Utility Operating Margins -- Pro-Formed for Phase I Increase** | | | | $ 2,204,454 | $ 10,738,655 | $ 550,224 | $ 3,007,021 |
| **Net Cost Rate Base** | | | | $ 51,614,612 | $ 174,682,903 | $ 6,657,070 | $ 15,048,330 |
| **Rate of Return** | | | | 4.27% | 6.15% | 8.27% | 19.98% |
| **Dollar Subsidy** | | | | $ (678,919) | $ 980,258 | $ 178,336 | $ 2,166,368 |

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

**12 Months Ended**
**December 31, 2011**

| 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 | 0.786783 | 0.065889 | 0.022237 |
| **Customer Allocation Factors** | | | | | | | |
| Rev | | R01 | | 937,679,951 | 771,730,096 | 56,378,640 | 18,785,745 |
| Energy | | Energy | | 13,854,274,000 | 10,900,307,000 | 912,839,000 | 308,081,000 |
| FAC Revenue Allocator | | FACA | | (41,688,649) $ | (38,965,806) $ | (3,263,166) $ | (1,101,311) |
| Base Fuel Revenue Allocator | | BSFL | | 13,671,969,000 | 10,900,307,000 | 912,839,000 | 308,081,000 |
| Fuel Expense Applicable to FAC Allocator | | FACEX | | 458,049,751 | 359,462,685 | 30,102,964 | 10,159,679 |
| **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 | | 15,669,000 | 13,426,000 | 757,000 | 250,000 |
| | | | | | 0.8569 | 0.0483 | 0.0160 |
| Production 12 CP Demands | | 12CP | | 29,432,000 | 24,475,000 | 1,516,000 | 502,000 |
| | | | | | 0.8316 | 0.0515 | 0.0171 |

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

12 Months Ended
December 31, 2011

| 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 | 0.023085 | 0.069939 | 0.013159 | 0.018908 |
| **Customer Allocation Factors** | | | | | | | |
| Rev | | R01 | | 19,002,098 | 48,697,556 | 9,009,512 | 14,076,304 |
| Energy | | Energy | | 319,824,000 | 968,960,000 | 182,305,000 | 261,958,000 |
| FAC Revenue Allocator | | FACA | | $ (1,143,289) | $ (3,463,784) | $ 7,185,140 | $ (936,433) |
| Base Fuel Revenue Allocator | | BSFL | | 319,824,000 | 968,960,000 | - | 261,958,000 |
| Fuel Expense Applicable to FAC Allocator | | FACEX | | 10,546,932 | 31,953,684 | 7,185,140 | 8,638,667 |
| **Customer Allocators** | | | | | | | |
| Customers (Metering Points) | | Cust05 | | 12 | - | - | - |
| **Demand Allocators** | | | | | | | |
| Steam - Direct Assignment | | STMD | | - | - | - | 1 |
| Substation Allocator | | SUBA | | 876,646 | - | - | - |
| Production 6 CP Demands | | 6CP | | 276,000 | 960,000 | - | - |
| | | | | 0.0176 | 0.0613 | - | - |
| Production 12 CP Demands | | 12CP | | 552,000 | 1,920,000 | 467,000 | - |
| | | | | 0.0188 | 0.0652 | 0.0159 | - |

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

**12 Months Ended**
**December 31, 2011**

| Description | Ref | Name | Allocation Vector | Total System | Rate E | Rate B | Rate C |
|---|---|---|---|---|---|---|---|
| ***Production Energy Allocation*** | | | | - | | | |
| Production Energy Residual Allocator | | PENGA | | 13,671,969,000 | 10,900,307,000 | 912,839,000 | 308,081,000 |
| Production Energy Costs | | | | $ 75,713,464 | | | |
| Member Specific Assignment | | | | $ 7,185,140 | - | - | - |
| Production Energy Residual | | | PENGA | $ 68,528,324 | $ 54,635,859 | $ 4,575,444 | $ 1,544,201 |
| Production Energy Total | | PENGT | | $ 75,713,464 | $ 54,635,859 | $ 4,575,444 | $ 1,544,201 |
| Production Energy Total Allocator | | PENG | PENGT | 1.000000 | 0.72161 | 0.06043 | 0.02040 |
| | | | | | | | |
| On-Peak kWh | | PENG_ON | | 6,681,883 | 5,578,150 | 418,041 | 137,854 |
| Off-Peak kWh | | PENG_OFF | | 6,990,086 | 5,322,157 | 494,798 | 170,227 |
| Purchased Power Expense | | | | 42,997,833 | | | |
| Member Specific Assignment | | | | (7,185,140) | | | |
| PP Expense Residual | | | PENGA | 35,812,693 | $ 28,552,533 | $ 2,391,113 | $ 806,995 |
| PP Expense Total | | PPPENG | | 42,997,833 | 28,552,533 | 2,391,113 | 806,995 |
| | | | | | | | |
| PP Expense Residual - On-Peak (67%) | | | PENG_ON | 23,994,504 | $ 20,031,023 | $ 1,501,178 | $ 495,031 |
| PP Expense Residual - Off-Peak (33%) | | | PENG_OFF | 11,818,189 | $ 8,998,208 | $ 836,558 | $ 287,804 |
| PP Expense Total | | PPTOU | | 42,997,833 | 29,029,232 | 2,337,736 | 782,835 |
| | | | | | | | |
| | | | | | - | 1.00000 | 2.00000 |
| Monthly Energy - Jan | | PENG_JAN | | 1,389,909,000 | 1,158,733,000 | 74,936,000 | 25,690,000 |
| Monthly Energy - Feb | | PENG_FEB | | 1,188,423,000 | 971,461,000 | 71,021,000 | 24,848,000 |
| Monthly Energy - Mar | | PENG_MAR | | 1,158,760,000 | 921,128,000 | 75,164,000 | 26,134,000 |
| Monthly Energy - Apr | | PENG_APR | | 967,471,000 | 741,519,000 | 71,819,000 | 26,282,000 |
| Monthly Energy - May | | PENG_MAY | | 980,346,000 | 742,755,000 | 75,443,000 | 25,697,000 |
| Monthly Energy - Jun | | PENG_JUN | | 1,080,926,000 | 847,576,000 | 77,600,000 | 25,570,000 |
| Monthly Energy - Jul | | PENG_JUL | | 1,203,908,000 | 977,006,000 | 79,033,000 | 26,730,000 |
| Monthly Energy - Aug | | PENG_AUG | | 1,199,912,000 | 959,469,000 | 82,941,000 | 25,734,000 |
| Monthly Energy - Sep | | PENG_SEP | | 1,035,898,000 | 799,402,000 | 79,233,000 | 25,349,000 |
| Monthly Energy - Oct | | PENG_OCT | | 988,726,000 | 758,650,000 | 78,471,000 | 25,094,000 |
| Monthly Energy - Nov | | PENG_NOV | | 1,116,700,000 | 886,531,000 | 74,270,000 | 25,990,000 |
| Monthly Energy - Dec | | PENG_DEC | | 1,360,990,000 | 1,136,077,000 | 72,908,000 | 24,963,000 |
| Monthly Fuel Exp Jan | | | PENG_JAN | 43,676,080 | 36,411,675 | 2,354,766 | 807,275 |
| Monthly Fuel Exp Feb | | | PENG_FEB | 36,843,359 | 30,117,127 | 2,201,785 | 770,335 |
| Monthly Fuel Exp Mar | | | PENG_MAR | 39,004,590 | 31,005,748 | 2,530,067 | 879,687 |
| Monthly Fuel Exp Apr | | | PENG_APR | 32,471,704 | 24,887,966 | 2,410,496 | 882,116 |
| Monthly Fuel Exp May | | | PENG_MAY | 31,779,715 | 24,077,767 | 2,445,623 | 833,015 |
| Monthly Fuel Exp Jun | | | PENG_JUN | 35,263,730 | 27,651,006 | 2,531,594 | 834,186 |
| Monthly Fuel Exp Jul | | | PENG_JUL | 40,266,864 | 32,677,719 | 2,643,401 | 894,033 |
| Monthly Fuel Exp Aug | | | PENG_AUG | 40,513,875 | 32,395,548 | 2,800,423 | 868,884 |
| Monthly Fuel Exp Sep | | | PENG_SEP | 32,902,155 | 25,390,578 | 2,516,596 | 805,134 |
| Monthly Fuel Exp Oct | | | PENG_OCT | 34,187,042 | 26,231,736 | 2,713,281 | 867,672 |
| Monthly Fuel Exp Nov | | | PENG_NOV | 36,861,486 | 29,263,768 | 2,451,601 | 857,912 |
| Monthly Fuel Exp Dec | | | PENG_DEC | 42,182,676 | 35,211,697 | 2,259,719 | 773,706 |
| Total Fuel Expense - Monthly Allocation | | PENG_MON | | 445,953,276 | 355,322,335 | 29,859,352 | 10,073,954 |

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

12 Months Ended
December 31, 2011

| Description | Ref | Name | Allocation Vector | Rate G | Large Special Contract | Special Contract Pumping Stations | Steam Service |
|---|---|---|---|---|---|---|---|
| **Production Energy Allocation** | | | | | | | |
| Production Energy Residual Allocator | | PENGA | | 319,824,000 | 968,960,000 | - | 261,958,000 |
| Production Energy Costs | | | | | | | |
| Member Specific Assignment | | | | $ - | - | $ 7,185,140 | - |
| Production Energy Residual | | | PENGA | $ 1,603,061 | $ 4,856,740 | $ - | $ 1,313,018 |
| Production Energy Total | | PENGT | | $ 1,603,061 | $ 4,856,740 | $ 7,185,140 | $ 1,313,018 |
| Production Energy Total Allocator | | PENG | PENGT | 0.02117 | 0.06415 | 0.09490 | 0.01734 |
| | | | | | | | |
| On-Peak kWh | | PENG_ON | | 145,082 | 284,874 | - | 117,881 |
| Off-Peak kWh | | PENG_OFF | | 174,742 | 684,086 | - | 144,077 |
| Purchased Power Expense | | | | | | | |
| Member Specific Assignment | | | | | | (7,185,140) | |
| PP Expense Residual | | | PENGA | $ 837,755 | $ 2,538,118 | $ - | $ 686,179 |
| PP Expense Total | | PPPENG | | 837,755 | 2,538,118 | 7,185,140 | 686,179 |
| | | | | | | | |
| PP Expense Residual - On-Peak (67%) | | | PENG_ON | $ 520,986 | $ 1,022,977 | $ - | $ 423,309 |
| PP Expense Residual - Off-Peak (33%) | | | PENG_OFF | $ 295,438 | $ 1,156,589 | $ - | $ 243,591 |
| PP Expense Total | | PPTOU | | 816,424 | 2,179,566 | 7,185,140 | 666,901 |
| | | | | | | | |
| | | | | 3.00000 | 4.00000 | | 6.00000 |
| Monthly Energy - Jan | | PENG_JAN | | 27,357,000 | 78,593,000 | - | 24,600,000 |
| Monthly Energy - Feb | | PENG_FEB | | 25,945,000 | 72,746,000 | - | 22,402,000 |
| Monthly Energy - Mar | | PENG_MAR | | 27,118,000 | 86,330,000 | - | 22,886,000 |
| Monthly Energy - Apr | | PENG_APR | | 25,780,000 | 80,599,000 | - | 21,472,000 |
| Monthly Energy - May | | PENG_MAY | | 26,477,000 | 88,090,000 | - | 21,884,000 |
| Monthly Energy - Jun | | PENG_JUN | | 25,916,000 | 84,282,000 | - | 19,982,000 |
| Monthly Energy - Jul | | PENG_JUL | | 25,695,000 | 75,552,000 | - | 19,892,000 |
| Monthly Energy - Aug | | PENG_AUG | | 27,351,000 | 84,244,000 | - | 20,173,000 |
| Monthly Energy - Sep | | PENG_SEP | | 27,293,000 | 84,751,000 | - | 19,870,000 |
| Monthly Energy - Oct | | PENG_OCT | | 28,247,000 | 75,601,000 | - | 22,663,000 |
| Monthly Energy - Nov | | PENG_NOV | | 25,171,000 | 83,191,000 | - | 21,547,000 |
| Monthly Energy - Dec | | PENG_DEC | | 27,474,000 | 74,981,000 | - | 24,587,000 |
| Monthly Fuel Exp Jan | | | PENG_JAN | 859,658 | 2,469,683 | - | 773,023 |
| Monthly Fuel Exp Feb | | | PENG_FEB | 804,344 | 2,255,263 | - | 694,504 |
| Monthly Fuel Exp Mar | | | PENG_MAR | 912,809 | 2,905,922 | - | 770,357 |
| Monthly Fuel Exp Apr | | | PENG_APR | 865,267 | 2,705,184 | - | 720,675 |
| Monthly Fuel Exp May | | | PENG_MAY | 858,301 | 2,855,599 | - | 709,410 |
| Monthly Fuel Exp Jun | | | PENG_JUN | 845,474 | 2,749,585 | - | 651,885 |
| Monthly Fuel Exp Jul | | | PENG_JUL | 859,415 | 2,526,972 | - | 665,324 |
| Monthly Fuel Exp Aug | | | PENG_AUG | 923,480 | 2,844,418 | - | 681,122 |
| Monthly Fuel Exp Sep | | | PENG_SEP | 866,879 | 2,691,858 | - | 631,110 |
| Monthly Fuel Exp Oct | | | PENG_OCT | 976,693 | 2,614,045 | - | 783,615 |
| Monthly Fuel Exp Nov | | | PENG_NOV | 830,877 | 2,746,077 | - | 711,251 |
| Monthly Fuel Exp Dec | | | PENG_DEC | 851,532 | 2,323,969 | - | 762,052 |
| Total Fuel Expense - Monthly Allocation | | PENG_MON | | 10,454,729 | 31,688,575 | - | 8,554,330 |

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

**12 Months Ended**
**December 31, 2011**

| Description | Ref | Name | Allocation Vector | Total System | Rate E | Rate B | Rate C |
|---|---|---|---|---|---|---|---|
| Monthly Purch Pwr Exp - Jan | | | PENG_JAN | 8,286,853 | 6,908,546 | 446,780 | 153,168 |
| Monthly Purch Pwr Exp - Feb | | | PENG_FEB | 7,366,059 | 6,021,290 | 440,201 | 154,012 |
| Monthly Purch Pwr Exp - Mar | | | PENG_MAR | - | - | - | - |
| Monthly Purch Pwr Exp - Apr | | | PENG_APR | - | - | - | - |
| Monthly Purch Pwr Exp - May | | | PENG_MAY | - | - | - | - |
| Monthly Purch Pwr Exp - Jun | | | PENG_JUN | - | - | - | - |
| Monthly Purch Pwr Exp - Jul | | | PENG_JUL | - | - | - | - |
| Monthly Purch Pwr Exp - Aug | | | PENG_AUG | - | - | - | - |
| Monthly Purch Pwr Exp - Sep | | | PENG_SEP | - | - | - | - |
| Monthly Purch Pwr Exp - Oct | | | PENG_OCT | - | - | - | - |
| Monthly Purch Pwr Exp - Nov | | | PENG_NOV | - | - | - | - |
| Monthly Purch Pwr Exp - Dec | | | PENG_DEC | 8,286,853 | 6,917,393 | 443,925 | 151,996 |
| | | PPMON | | 23,939,765 | 19,847,229 | 1,330,906 | 459,176 |
| FAC Expense Residual Allocator | | FACALL | | 450,864,611 | 359,462,685 | 30,102,964 | 10,159,679 |
| FAC Expense Cost | | | | $ (7,185,140) | | | |
| Member Specific Assignment | | | | $ (7,185,140) | - | - | - |
| FAC Expense Residual | | | FACALL | $ - | $ - | $ - | $ - |
| FAC Expense Total | | FACT | | $ (7,185,140) | $ - | $ - | $ - |
| FAC Expense Allocator | | FACAL | FACT | 1.000000 | - | - | - |

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

**12 Months Ended**
**December 31, 2011**

| Description | Ref | Name | Allocation Vector | Rate G | Large Special Contract | Special Contract Pumping Stations | Steam Service |
|---|---|---|---|---|---|---|---|
| Monthly Purch Pwr Exp - Jan | | | PENG_JAN | 163,107 | 468,584 | - | 146,669 |
| Monthly Purch Pwr Exp - Feb | | | PENG_FEB | 160,812 | 450,893 | - | 138,852 |
| Monthly Purch Pwr Exp - Mar | | | PENG_MAR | - | - | - | - |
| Monthly Purch Pwr Exp - Apr | | | PENG_APR | - | - | - | - |
| Monthly Purch Pwr Exp - May | | | PENG_MAY | - | - | - | - |
| Monthly Purch Pwr Exp - Jun | | | PENG_JUN | - | - | - | - |
| Monthly Purch Pwr Exp - Jul | | | PENG_JUL | - | - | - | - |
| Monthly Purch Pwr Exp - Aug | | | PENG_AUG | - | - | - | - |
| Monthly Purch Pwr Exp - Sep | | | PENG_SEP | - | - | - | - |
| Monthly Purch Pwr Exp - Oct | | | PENG_OCT | - | - | - | - |
| Monthly Purch Pwr Exp - Nov | | | PENG_NOV | - | - | - | - |
| Monthly Purch Pwr Exp - Dec | | | PENG_DEC | 167,285 | 456,547 | - | 149,706 |
| | | PPMON | | 491,203 | 1,376,024 | - | 435,227 |
| FAC Expense Residual Allocator | | FACALL | | 10,546,932 | 31,953,684 | - | 8,638,667 |
| FAC Expense Cost | | | | | | | |
| Member Specific Assignment | | | | $ - | - | (7,185,140) | - |
| FAC Expense Residual | | | FACALL | $ - | $ - | $ - | $ - |
| FAC Expense Total | | FACT | | $ - | $ - | $ (7,185,140) | $ - |
| FAC Expense Allocator | | FACAL | FACT | - | - | 1.00000 | - |

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

| | | |
|---|---|---|
| GENERAL ADJUSTMENT OF ELECTRIC | ) | |
| RATES OF EAST KENTUCKY POWER | ) | CASE NO. |
| COOPERATIVE, INC. | ) | 2010-000167 |

EXHIBIT ___(SJB-3)

OF

STEPHEN J. BARON

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC CASE NO. 2010-00167**
**FIRST DATA REQUEST RESPONSE**

**GALLATIN'S FIRST DATA REQUEST DATED 07/08/10**
**REQUEST 7**
**RESPONSIBLE PERSON:** **John R. Twitchell**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 7.** If not provided in response to the previous question, please provide all workpapers supporting the development of the test year level of Purchased Power expense, including any production cost analyses showing the days, times, and cost of projected power purchases. Specifically identify any purchased power capacity costs and the mW level of each such purchase included in test year purchased power expenses.

**Request 7.** Provided on page 2 of this response is a chart of monthly expected purchase power amounts and expense. The "Purch Winter Pking" is by far the largest purchase power component. This is a winter season peaking purchase utilized to serve peak load during EKPC's winter peak load season. The cost for this purchase includes a $6.50/MWh premium to represent a heat rate Call Option type product, for 200 MW each month.