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MAY 24 2011
PUBLIC SERVICE
COMMISSION

Via Hand Delivery

May 24, 2011

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2011-00036

Dear Mr. Derouen:

Please find enclosed the original and twelve (12) copies of the PUBLIC REDACTED VERSION OF THE DIRECT TESTIMONY AND EXHIBITS of the following KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. witnesses to be filed in the above-referenced docket.

Henry W. Fayne
Stephane Leblanc
Paul A. Coomes
Gene Strong
Dr. Mathew J. Morey
Charles W. King
Lane Kollen
Stephen J. Baron

By copy of this letter, all parties listed on the Certificate of Service have been served. I also enclose a copy of the CONFIDENTIAL pages to be filed under seal.

Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service
David C. Brown, Esq.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by electronic mail (when available) or by mailing a true and correct copy by regular ordinary U.S. mail, unless other noted, this 24th day of May, 2011 to the following

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COMMONWEALTH OF KENTUCKY

RECEIVED

MAY 24 2011

PUBLIC SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

REDACTED

DIRECT TESTIMONY AND EXHIBITS

OF

HENRY W. FAYNE

ON BEHALF OF THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

MAY 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	**CASE NO. 2011-00036**

DIRECT TESTIMONY OF HENRY W. FAYNE

Q: Please state your name and business address.

A: My name is Henry W. Fayne. My business address is 1980 Hillside Drive, Columbus, Ohio 43221.

Q: Please briefly describe your business and educational background.

A: I have been a consultant in the electric energy sector since the beginning of 2005, following my retirement from American Electric Power (AEP). I was employed by AEP in various positions for thirty years from 1974 through 2004, including as Executive Vice President and Chief Financial Officer from 1998 until 2001, and as Executive Vice President Energy Delivery from 2001 until I retired in 2004. I have a bachelors degree in economics from Columbia College and an MBA in finance from Columbia Graduate School of Business.

Q: Have you testified previously?

A: Yes. During my tenure at AEP, I testified before the regulatory commissions in the states of Indiana, Kentucky, Michigan, Ohio, Oklahoma, Texas, Virginia and West Virginia on behalf of various operating companies of AEP. I have also testified before the Federal Energy Regulatory Commission. Since I retired from AEP, I have testified before regulatory commissions in the states of Missouri, Ohio and West Virginia. I have also testified before this Commission in Case No. 2007-00455.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to explain why the rate treatment proposed by KIUC is a critical and reasonable step in finding a solution to support the long term viability of the Hawesville and Sebree smelters. Specifically, my testimony is intended to provide the following:

a. To summarize the KIUC rate proposal,
b. To explain why the proposed rate treatment is necessary and in the long term best interest of the smelters, Big Rivers, its members and the State of Kentucky, and
c. To explain why the proposed rate treatment is consistent with
    i. The Existing smelter Retail and Wholesale Agreements
    ii. Historical PSC orders and agreements between the smelters and Big Rivers
    iii. Rate treatment in other states

Q: Please identify the witnesses who will testify for KIUC and the areas which their testimony will address.

A: In addition to my testimony, KIUC presents the testimony of seven witnesses:

1. **Stephane Leblanc:** Mr. Leblanc, General Manager of the Sebree smelter, provides an explanation of the operation of the Sebree smelter and issues facing aluminum smelters operating in the U.S.
2. **Stephen J. Baron**. Mr. Baron, President and a Principal of Kennedy and Associates, provides testimony on a variety of cost of service, revenue allocation and rate design issues.
3. **Lane Kollen**. Mr. Kollen, a Principal of Kennedy and Associates, provides testimony regarding a variety of revenue requirement adjustments and presents a recommendation regarding the use of patronage capital.
4. **Charles King.** Mr. King, President Emeritus of Snavely King Majoros & O'Connor, provides testimony critiquing the Big Rivers' depreciation study.
5. **Dr. Mathew J. Morey**. Dr. Morey, a Senior Consultant with Christensen Associates Energy Consulting, LLC., provides testimony regarding the impact on Big Rivers' financial margins if the smelters were to curtail operations and the smelter load was sold into the wholesale power market.

6. **Paul Coomes, Ph.D.** Dr. Coomes, professor at the University of Louisville, provides testimony and a report describing the economic and fiscal impacts if the two aluminum smelters were to shut down.
7. **Gene Strong.** Mr. Strong, formerly Secretary of the Kentucky Economic Development Cabinet, provides testimony regarding the issues associated with economic development in western Kentucky and the difficulty in replacing the smelter jobs if they were lost.

Q: Before you begin discussing the KIUC proposal, please describe the operations of the Hawesville and Sebree smelters.

A: Rio Tinto Alcan's Sebree Smelter has been in operation since 1972; it is their only U.S. aluminum smelter. It produces about 196,000 metric tons of primary aluminum from its 3 potlines, with about 495 employees. Its peak electrical demand is currently approximately 355 MW, with an annual energy consumption of approximately 3.1 billion kilowatthours.

Century's Hawesville Smelter has been in operation since 1970. It produces about 244,000 metric tons of primary aluminum from its 5 potlines, with about 775 employees. More than half of the aluminum is delivered in molten form to Southwire Rod and Cable Mill adjacent to the Hawesville Smelter. Hawesville's peak electrical demand is approximately 482 MW, with an annual energy consumption of approximately 4.2 billion kilowatthours.

Together, the two Smelters consume about 7.3 billion kilowatthours of electricity and account for about 70% of the Big Rivers system energy requirement and 56% of Big Rivers system peak demand. As described in detail in the testimony of Dr. Paul Coomes, with about 1300 employees, the two Smelters support over 4700 jobs in the region and are critical to the economic health of Western Kentucky.

Q: Please summarize the rate treatment proposed by the KIUC in this proceeding.

A: As explained in more detail in the testimony of KIUC witnesses Baron and Kollen, we are proposing (a) several revenue requirement adjustments that would reduce the revenue deficiency from $39.95 million proposed by Big Rivers to $18.68 million and (b) a cost of service that recognizes the significant subsidies that the smelters are currently paying, including the fact that the smelters are actually paying and are projected to continue to pay the full $1.95/MWh TIER Adjustment Charge. On that basis, as shown on Baron Exhibit SJB-6, after reflecting cost-of-service adjustments, the rate increase would be $18.7 million for the Rurals, $0.03 million for the Large Industrials, and $0.2 million for the smelters. However, to limit the increase to the Rurals to the $14.17 million level proposed by Big Rivers, we are recommending that the Commission authorize an annual amortization of $4.26 million from the Rural Reserve.

Finally, to further benefit all customers and, importantly, to maximize the smelters' ability to weather a downturn in aluminum pricing and to optimize the opportunity for the development of a mechanism to ensure the long term operation of the smelters, we are proposing that the Commission make the distribution of patronage capital to the full extent available a fundamental component of its rate order in this proceeding. For example, if Big Rivers is able to distribute 25% of its earnings as patronage capital, as shown on Baron Exhibit__(SJB-6), the effective rate changes would be an increase of $13.55 million for the Rurals, and a decrease of $0.20 million for the Large Industrials and $1.62 million for the smelters.

Q: Why is it appropriate to establish rates on the assumption that the smelters will continue to be at the top of the TIER.

A: First, the smelters are currently paying $1.95/MWh, which is the top of the bandwidth and are expected to continue to pay at that level through the end of 2011 at which time the top of the bandwidth moves up to $2.95/MWh. But more importantly, the Big Rivers' forecast projects that, even if the full rate request is approved, the smelters will be charged [redacted] in 2012 and beyond.

Q: Does the KIUC proposal place a disproportionate burden on Big Rivers' other customers?

A: No, it does not. Like Big Rivers, we are proposing that the Rural Reserve be used to limit the impact on the rural customers. Moreover, if Big Rivers agrees to and is able to distribute the patronage capital as proposed, the increase to rural customers would be less than the amount requested by Big Rivers.

The KIUC proposal presents a unique solution. As explained in more detail below, it reduces the risk of a smelter curtailment and the consequent catastrophic impact such an event would have on Big Rivers' other retail customers and the economy in general. And it accomplishes that outcome without imposing a burden on the rural customers because the Commission created the Rural Reserve.

Q: Please explain why the proposed rate outcome for the smelters is necessary.

A: Aluminum is a global commodity, much like copper, nickel, zinc and oil. It is sold at a price that is based on global supply and demand and established by trading activity on the London Metal Exchange, or LME. An individual smelter is, in effect, a price taker and cannot set the selling price of the base product; therefore, the success or viability of a specific smelting operation is determined primarily by its cost of production.

The cost of production will vary among smelters based on the cost of raw materials and services as well as the configuration of the plant. However, in general, the cost of alumina, labor and electricity accounts for 75%-80% of the cost, with alumina and electricity each comprising about one-third of the cost of production. The cost of alumina tends to be tied to the LME price. As a result, it is the cost of electricity that most significantly determines the ongoing success or viability of an aluminum smelter. Because of transportation costs, the location of a smelter can make some contribution to the viability of any specific smelter; but the differences in the cost of transportation are not sufficient to offset electricity prices that are materially higher than those paid by other aluminum smelters.

That outcome is most dramatically shown by the shifts in production. In the U.S. in 1978, there were 34 smelters, producing more than 4 million metric tons, accounting for about 31% of the world supply. Today, there are only 10 smelters operating in the U.S., producing about 1.9 million metric tons, which accounts for only 4.2% of the world supply. In every instance, the smelters shut down primarily because of high power costs. HWF Exhibit 1 shows the U.S. smelters currently in operation and their cost of electricity.

Q: What is the current cost of electricity incurred by the Hawesville and Sebree smelters?

A: For the year 2010, the cost of electricity charged by Big Rivers (via Kenergy) was $45.22/MWh for the Hawesville smelter and $43.45 for the Sebree smelter. The average cost for each of the smelters differs because of the different level of operations at each of the facilities.

Q: How does the cost of $43/MWh - $45/MWh compare to the cost of electricity at other smelters both in the U.S. and abroad?

A: As shown on HWF Exhibit 1, even with current rates, the cost of electricity for Sebree and Hawesville is among the highest cost for U.S. smelters and significantly higher than the average world price excluding China of $27/MWh. If the rate increase proposed by Big Rivers is approved by the Commission, the cost of electricity to the smelters is projected to increase to [redacted] in September 2011, making the cost of electricity to the Kentucky smelters among the highest in the U.S., and therefore, the most vulnerable to closure. More importantly, as discussed in more detail below, the cost of electricity to the smelters is projected to increase even more beginning in 2012, just four months after the new rates in this proceeding become effective.

Q: You explained that the price of aluminum varies based on global supply and demand. What is the current price on the LME?

A: The current LME price is about $2500 per metric ton.

Q: Isn't it true that the current price of aluminum is significantly higher than in July 2009 when the contract was signed?

A: Yes. In July 2009, the LME price of aluminum was approximately $1650 /tonne. But as shown on HWF Exhibit 2, LME prices have been extremely volatile; it has ranged between $1330/tonne and $3071/tonne in the last five years. As I mentioned earlier, the critical factor is to have a cost of electricity that will allow the smelters to weather a downturn. The current cost of electricity is already among the highest in the world and Big Rivers' proposal aggravates the risk of closure. And as I've already noted, the cost of electricity is expected to increase dramatically.

Q: What is the long term outlook for aluminum prices?

A: As I explained above, the price of aluminum is based on global supply and demand. Like many other commodities, the price can vary widely and is difficult to predict. The near term forward curve projects LME price in the range of $2700-$2800 per metric ton. But recent history shows that even near term forward curves are far from certain. For example, in July 2008, current prices were $3070/tonne, the 3-month forward curve was $3121/tonne and the 15-month forward curve was $3230/tonne; nonetheless, actual prices plummeted to

$1400//tonne by January 2009 (just 6 months later) and fell even further in February 2009.

Q: How does the KIUC proposal benefit the smelters?

A: The KIUC proposal benefits the smelters because it essentially eliminates an increase in rates, thereby avoiding aggravating the risk of closure when the LME inevitably moves through a down cycle. More importantly, it avoids increasing the smelters' cost of electricity to a level that may be too high to mitigate over the long term. Avoiding the need for an increase in smelter rates now preserves the opportunity for developing a long term solution.

Q: How does the KIUC proposal impact other constituencies?

A: The KIUC proposal benefits all constituencies.

Q: Please explain.

A: With amortization of the Rural Reserve, the rate increase to the Rurals reflected in the KIUC proposal is the same as the increase proposed by Big Rivers. The rate increase to the Large Industrials is less than proposed by Big Rivers. And if the Commission is successful in obtaining a commitment from Big Rivers regarding the distribution of patronage capital, the benefits to both the Rurals and the Large Industrials increase. But the significant benefit from the KIUC approach is that it reduces the real risk to the Rurals and Large Industrials that the smelters would be forced to curtail and significant rate increases would be required from Big Rivers' remaining customers. And it accomplishes that outcome without requiring the other customers to subsidize the smelter rates as has been done in other jurisdictions; as explained in the testimony of KIUC witness Baron, the Rural class will continue to receive over $6 million in subsidies at KIUC proposed rates. Moreover, even with the $14 million rate increase proposed by Big Rivers, the electricity rates to rural customers will continue to be among the lowest in the U.S. and, as noted by Big Rivers (Blackburn Exhibit 4) , lower than the rates that were actually in effect in 1994.

Q: How does the KIUC proposal benefit Big Rivers.

A: Although KIUC is proposing a lower revenue requirement than the Big Rivers' request, the significant difference between the two is the manner in which the revenue requirement is allocated. By recognizing the significant subsidy that the smelters are providing, part of the revenue deficiency would be met by using funds from the Rural Reserve. But most importantly, the KIUC approach would reduce the risk that the smelters would be forced to curtail. Lowering the risk of a smelter curtailment should prevent deterioration of credit ratings (particularly important in the face of refinancing), would minimize the need for large rate increases and would decrease the risk of Big Rivers' financial condition deteriorating. As noted in the testimony of KIUC witness Morey, Big Rivers' margin would deteriorate by approximately $83 million per year if the smelters shut down and Big Rivers were forced to sell the excess energy in the wholesale market. If such a shortfall had to be made up from the remaining customers, wholesale rates to the Members would have to increase by more than 55%.

Q: Please discuss the KIUC proposal in the context of the existing agreements, historical KPSC orders, and the rate treatment in other states.

A: We believe that the KIUC proposal is consistent with the existing agreements, consistent with historical KPSC treatment, consistent with the smelters' long term relationship with Big Rivers, and consistent with rate treatment that is being approved in other states.

Q: Please briefly summarize the existing contractual arrangements among Big Rivers, Kenergy, and the two smelters.

A: The power arrangement among Big Rivers, Kenergy and the two smelters is governed by a complex series of agreements dated July 2009 and approved by this Commission in Case No. 2007-00045. The primary terms of the arrangement, however, are defined in the Retail Electric Services Agreement between Kenergy and separately each of the smelters, the Wholesale Electric Service Agreement between Big Rivers and Kenergy, and a Coordination Agreement between Big Rivers and separately each of the smelters.

In summary, each smelter has a firm take-or-pay contract (Hawesville for 482 MW and Sebree for 368 MW) through 2023; the major components of cost of such service for each of the smelters is comprised of the following (all charges are defined in Section 4 of the Retail Services Agreement) :

a) Base Energy Charge, which is equal to the Large Industrial Rate (adjusted for a 98% load factor) plus \$0.25/MWh
b) Fuel Adjustment Charge (FAC), which is the same factor that is applicable to all other customers

c) Non-FAC Purchased Power Adjustment, which provides recovery for the smelters' share of all purchased power costs incurred by Big Rivers but not recovered through the FAC or through base rates

d) Environmental Surcharge, which provides recovery of environmental costs approved by the Commission under the terms of the Environmental Surcharge Rider to the Big Rivers' Tariff

e) TIER Adjustment, which is an incremental charge to the smelters, equal to the amount necessary for Big Rivers to achieve a TIER (interest coverage) of 1.24 for the calendar year; the charge to the smelters is capped at $1.95/MWh through 2011 and increases to $2.95/MWh for the years 2012-2014.

f) Various Surcharges, which potentially amount to approximately $1.90/MWh in 2012.

In short, beginning in 2012, the smelters' rates would be equal to the large industrial rate plus $0.25/MWh plus up to another $4.85/MWh to cover the Surcharges and the TIER Adjustment Charge. On that basis, the smelters would be paying a premium of approximately $37 million per year above the Large Industrial Rate.

Q: Please explain why you have concluded that the KIUC proposal is consistent with the Retail and Wholesale Agreements that are currently in effect.

A: The KIUC proposal does not propose any changes to the Retail or Wholesale Agreements that are in place; all contract terms are maintained. The KIUC proposal simply addresses the appropriateness of the revenue requirement and the class cost of service; pursuant to the terms of the existing contracts, the smelters have the right to address such issues.

The KIUC proposal also supports the underlying intent of the existing agreements. It is intended to provide a long term power supply that would sustain the long term operation of the smelters without placing an undue burden on the other members. The rate increase for other customers reflected in the KIUC proposal is less than the level proposed by Big Rivers. And at that level, the rates to rural customers are among the most competitive in the U.S.

Finally, the KIUC proposal provides that rates to the rural customers be offset by use of the Rural Reserve established by the Commission. The rural reserve is a mechanism that is not governed by the existing smelter contracts.

Q: Please explain why you have concluded that the KIUC proposal is consistent with historical KPSC treatment and the long term relationship with Big Rivers.

A: The development and continued operation of Big Rivers and the Hawesville and Sebree smelters have been inextricably intertwined for over 40 years. Throughout that history, the Commission has recognized that the survival of Big Rivers and the survival of the smelters were co-dependent. As a result, the Commission has considered and approved special rate mechanisms to balance the needs of the smelters and Big Rivers' other customers.

Q: Please elaborate.

A: In May 1985, in Case No. 9163 , for example, the Commission recognized that "…Big Rivers' viability is dependent upon the continued operation of the aluminum smelters and their fates are inextricably entwined." Further, the Commission directed Big Rivers to negotiate with the smelters to implement a variable rate tied to the price of aluminum - - clearly a novel approach.

Q: Please continue.

A: In 1987, the Commission established a variable rate for the smelters noting that "If either of the smelters were to close because of the burdensome flat rate in a recession, the Commission feels that the consequences for Big Rivers and its other customers would be disastrous."

And finally in March 1990, in Case 89-376, Big Rivers and the smelters reached a settlement by adding a balancing account mechanism to the variable rate tariff under which the average power price over the ten year term would be exactly 32 mills per kilowatthour.

It is noteworthy that the Commission's orders, and ultimately the settlement between Big Rivers and the smelters, recognize that applying traditional ratemaking principles may solve one piece of the problem, but may produce grave consequences if a balance among the parties is not achieved.

Q: Are there other examples?

A: Yes. To support Big Rivers' financial reorganization, Big Rivers and the smelters negotiated a non-traditional solution that the Commission approved. Specifically, in 1996-97, as part of the Big Rivers reorganization plan, Big Rivers and the smelters negotiated a three-tier structure with Tier 1 and Tier 2 at fixed rates with the ability to access the wholesale market (through Kenergy) for the balance of their needs. With the support of the smelters, therefore, Big Rivers successfully implemented its Plan of Reorganization and was able to emerge from Chapter 11 in 1998.

Q: Do you believe that the current agreements among Big Rivers, Kenergy, and the smelters support your conclusion that the Commission has considered and approved special rate mechanisms to balance the needs of the smelters and Big Rivers' other customers.

A: Absolutely. The current agreements among Big Rivers, Kenergy and the smelters were the result of serious, complex and highly contested negotiations over a period of five years; final agreement was reached only with the additional support provided by E.ON. Nonetheless, the Commission concluded that appropriate balance among the parties was not achieved and, therefore in its order in Case No. 2007-00455, required E.ON to contribute additional dollars to fund the Rural Reserve.

Q: Please explain why you have concluded that the KIUC proposal is consistent with what other states have approved.

A: As I explained above, aluminum smelters are uniquely energy intensive and sensitive to the price of electricity. As a result, the number of smelters remaining in the U.S. has declined dramatically. Several states, therefore, have taken steps to support the continued operations of the smelters in their state and to protect the high paying jobs. I have been involved in the negotiation of rates in Missouri, Ohio and West Virginia. In broad terms, the regulatory treatment has included discounted rates in return for a commitment that the smelter retain a minimum level of employment. In some cases, in recognition of the volatility in the price of aluminum and an understanding that in a downturn it is the smelters with the highest cost of electricity that shutdown, the treatment has tied the discount to the price of aluminum on the London Metal Exchange.

Q: Would you please provide some specific examples?

A: In Missouri, for example, the Commission has recognized the significant importance of the jobs created by the New Madrid smelter. As a result, in 2010, the Commission accepted a cost-of-service study that minimizes the revenue requirement assigned to the smelter and resulted in no increase being assigned to the smelter (Case No. ER-2010-0036).

In Ohio, pursuant to legislation passed to attract and retain energy-intensive industry, the Public Utilities Commission of Ohio approved a 10-year contract beginning in 2009 (Case No: 09-119-El-AEC) that provided a discounted rate tied to the LME and employment level at the smelter. To the extent that the rate paid by the Hannibal aluminum smelter is less than the tariff, the shortfall is allocated to other customers

In West Virginia, in 2006, the Public Service Commission of West Virginia approved a Special Contract for the Ravenswood smelter which indexed the price paid for electricity to the LME (Case No: 05-1278-E-PC-PW-42T); nonetheless, the smelter was shut down in 2009. However since that time, in an effort to support a restart of the smelter, the legislature passed a bill that provided a mandate for the Commission to approve special contracts for energy intensive industry to attract and retain jobs; the legislation authorizes the Commission to allocate to other customers any shortfall created. In addition, efforts are currently underway to determine if there are additional mechanisms for the State to provide supplemental support.

In February 2009, the New York Power Authority also developed an approach to support the continued operation of Alcoa's Massena smelter by approving a long term contract based on hydro power and indexed to the LME price of aluminum. In return, Alcoa has committed to make capital investments in the facilities and to maintain a minimum number of jobs.

Q: The rate increase that Big Rivers is proposing is not new news; increased rates were anticipated. Moreover, the aluminum market has improved significantly since mid-2009. Why did the smelters enter into the agreements in 2009 if they believed that any increase in rates would significantly put them at risk?

A: The smelters entered the current agreements in good faith based on the belief that the arrangement would support the continued operation of the smelters and an integrated Big Rivers, without imposing an undue burden on the other members. But there were two other critical considerations at the time. First, these agreements represented the only viable option for the smelters. Second, to compensate the smelters for the early termination of their existing power contracts, E.ON provided significant financial support which allowed the continued operations of the smelters under the new power arrangement now in effect.

Q: Please elaborate.

A: As the Commission is aware, the contracts in effect prior to the Unwind were set to expire at the end of 2010 for the Hawesville smelter and at the end of 2011 for the Sebree smelter. Absent the Unwind and the new retail and wholesale agreements that are now in place, each of the smelters would have been forced to purchase power (through Kenergy) at market rates when their contracts expired. Such an outcome would not have been viable and would have resulted in a curtailment of the smelters.

The Smelters decided to support the transaction because it appeared to be the best alternative available at the time. The Smelters require an affordable and predictable energy supply in order to make the large capital investments necessary to maintain and operate their production facilities efficiently. Although there was concern that the cost of electricity could be too high, which is why the termination clause requires only a one-year notice, the agreements did provide the opportunity for continued operation, particularly given the funds provided by E.ON.

In exchange for the Smelters' agreement to the early termination of the existing purchase power contracts, E.ON agreed to pay a sum of money at closing to offset the higher cost projected by Big Rivers through 2010 and 2011. Because of the funding from E.ON both smelters have continued to operate, although Hawesville did curtail its fifth potline during 2009. If not for the funding from E.ON, which partially offset the higher cost of electricity effective with the Unwind under the terms of the new contracts with Kenergy and Big Rivers, the Hawesville smelter would have had to curtail its total operation during the last downturn.

Q: Please explain why the smelters are now more concerned about the viability of the existing power supply.

A: The Big Rivers' forecast shows the cost of electricity for the smelters increasing to [redacted] in September if the proposed rate request is approved. But the forecast then shows the smelter rate increasing to [redacted] in 2012, to [redacted] in 2013, and to [redacted] in 2014. In each of those years, the smelters are [redacted] of the TIER Adjustment. And in each of those years, the rates to the smelters are projected to be significantly higher than the levels reflected in Big Rivers' financial forecast prepared just prior to the close of the Unwind. To make matters worse, Big Rivers has prepared presentations that show the smelter rates increasing by more than 20% in 2015 to comply with existing environmental regulations; if regulation associated with CO_2 is passed, it gets even worse.

Without the benefit of the funds from E.ON, the Kentucky smelters would already have among the highest cost of electricity of the U.S. smelters and a cost well above the average cost of electricity available to smelters outside the U.S. The increase proposed by Big Rivers in this proceeding and the significant increases anticipated by Big Rivers beginning in 2012 make capital investment decisions more difficult and substantially increase the risk that the smelters will not survive another downturn. If the cost of electricity escalates to [redacted] as Big Rivers projects, it even raises the question of whether the smelters can continue to operate even if the LME stays around today's price of $2500/tonne.

Q: At the outset, you indicated that the KIUC proposal is a critical step in finding a solution to support the long term viability of the Kentucky smelters. Please explain.

A: As I already explained, an increase in the cost of electricity, which is already among the highest for any smelter operating in the U.S., imposes additional hurdles to investing capital, increases the risk that the smelter will not be able to weather the aluminum price cycles, and consequently imposes significant risk on Big Rivers, its remaining customers, and the broader economy of western Kentucky.

At the same time, we recognize that Big Rivers' costs will increase (though not necessarily at the rate Big Rivers anticipates) and that Big Rivers must increase rates to recover its prudently incurred costs to meet its financial obligations (though, as our testimony in this proceeding demonstrates, not necessarily at the level Big Rivers proposes). We also understand that the size of Big Rivers in relationship to the size of the smelter load limits the extent to which a long term solution can be developed through the regulatory process. Specifically, the smelters represent about 70% of Big Rivers' load. It would be a significant challenge, therefore, to keep the cost of electricity to the smelters at competitive levels over the long term and to provide Big Rivers with appropriate cost recovery without imposing an unreasonable burden on the other customers.

It is for that reason that we believe it is critical to recognize that a long term solution must be developed. Our proposal in this proceeding is step one. It avoids a rate increase to the smelters which establishes a workable rate level for a long term solution, provides Big Rivers with a revenue stream that this Commission concludes is appropriate, and avoids placing a burden on the other customers because any additional increase is offset by use of the Rural Reserve. More importantly, it provides a window of time to develop a long term solution, which we believe must be a statewide solution.

Q: Please explain what you mean by a statewide solution.

A: To provide the smelters competitively-priced power to ensure their long term viability and to accomplish that result without placing an undue burden on either the electric provider or the other customers, a statewide solution that provides support from a larger population appears to the be the most viable approach. The development of a statewide economic development fund, provision of tax credits, or redistribution of the smelter load among multiple utilities are just a few examples of potential solutions. It goes without saying that a successful solution will also require Big Rivers to continuously re-evaluate its plans and operations to ensure that it operates efficiently and is keeping costs for all its customer as low as reasonable. Ultimately, however, any solution must reflect the State's public policy position regarding job attraction and retention, and the aluminum smelters in particular. But our success in finding a statewide solution will be greatly enhanced if we can implement interim solutions that do not aggravate the situation. The KIUC proposal is intended to do just that.

Q: Does that conclude your testimony?

A: Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBITS

OF

HENRY W. FAYNE

ON BEHALF OF THE
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

May 2011

Exhibit HWF-1

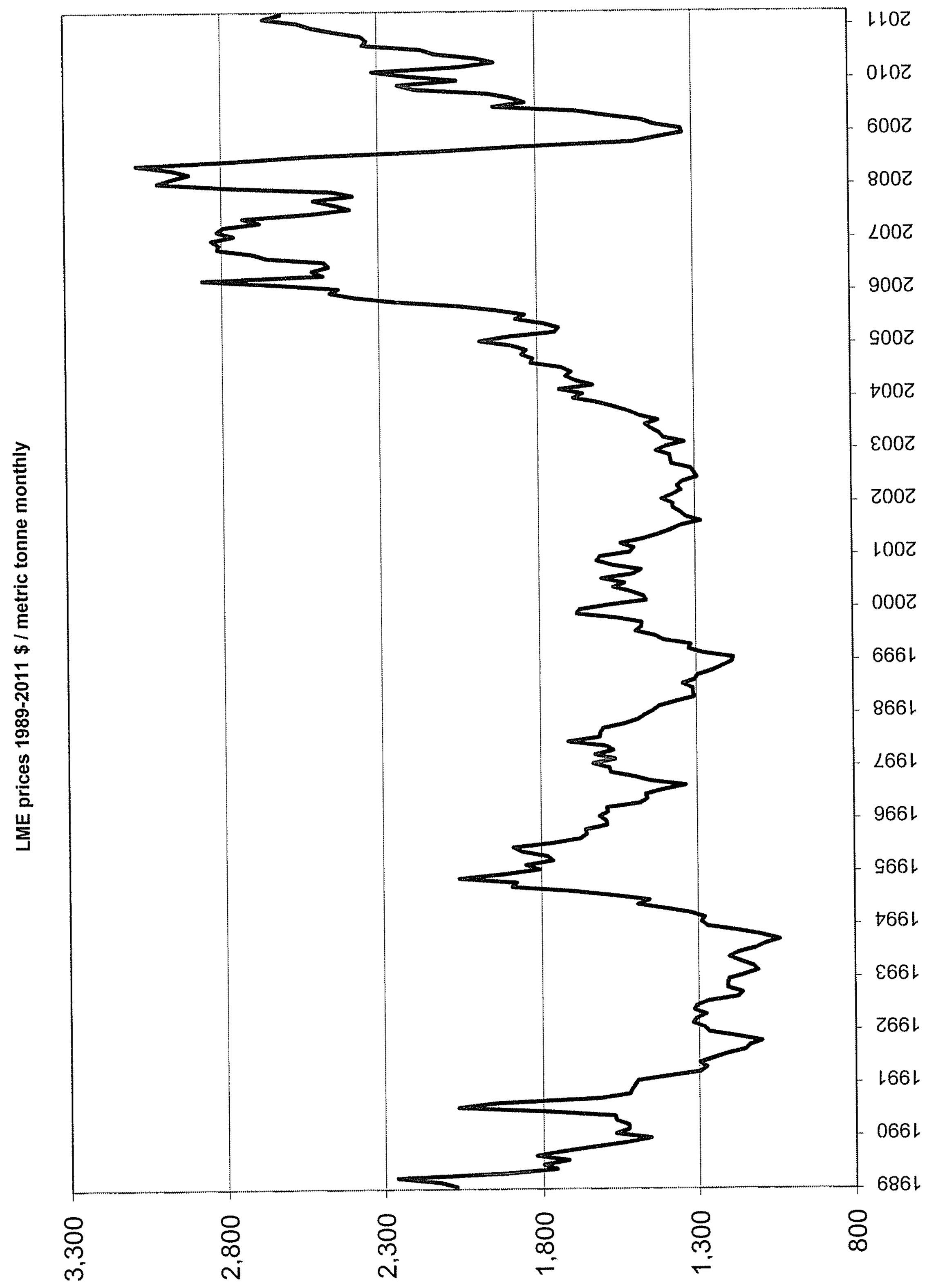
ALUMINUM SMELTERS
COST OF ELECTRICITY
FOR THE YEAR 2011

	Smelter	Company Owner	Smelter Production	Cost of Electricity [1]
			(000 TPY)	($/Mwh)
1	Mt. Holly	Century	229.0	52.26
2	Ferndale	Italco	143.5	49.71
3	Hawesville	Century	199.2	45.22
4	Sebree	Alcan	196.0	43.45
5	New Madrid	Noranda	263.0	39.45
6	Warrick	Alcoa	271.9	31.81
7	Hannibal	Ormet	180.9	24.20
8	Massena West	Alcoa	130.0	23.01
9	Wenatchee	Alcoa	99.9	13.48
	TOTAL USA		**1,713.4**	**37.57**
	GLOBAL (Excl USA & China)		**25,403.7**	**26.28**

[1] For the Hawesville and Sebree smelters, the cost reflected reflects actual charges from Kenergy for the year 2010. For all other smelters, the data was provided by CRU, an independent business analysis and consultancy group focused on mining, metals, power, cables, fertilizer and chemical sectors.

If the rates requested by Big Rivers is approved and both smelters operate at full production, the cost of electricity for the Hawesville and Sebree smelters would be $47.86/MWh.

HWF Exhibit 2



COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	)	
Corporation for a General Adjustment	)	
In Rates	)	**Case No. 2011-00036**

DIRECT TESTIMONY

OF

STEPHANE LEBLANC

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

MAY 2011

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:		
Application of Big Rivers Electric	**)**	
Corporation for a General Adjustment	**)**	
In Rates	**)**	**Case No. 2011-00036**

DIRECT TESTIMONY OF STEPHANE LEBLANC

Q. Please state your name and business address.

A. My name is Stephane Leblanc and I am General Manager of the Sebree smelter owned by Alcan Primary Products Corporation, a subsidiary of Rio Tinto plc. The smelter is part of the Rio Tinto Alcan aluminum group (RTA) headquartered in Montreal. My address is 9404 State Route 2096, Robards, Kentucky 42452.

Q. Please state your educational background and work experience.

A. I have been employed by Rio Tinto Alcan and its predecessors since 1990. I have a Bachelor Degree in Mechanical Engineering from the University of Sherbrooke in Quebec. I have held numerous management positions at smelters in Canada. Before taking the job as General Manager of the Sebree plant in 2008, I was the Director of Environment, Health and Safety for the Primary Metal Group of RTA.

Q. Mr. Leblanc, would you describe the Sebree smelter.

A. Sebree is a three potline operation that produces 196,000 metric tonnes of aluminum per year. The product in the form of billet and remelt is sold to third parties. Sebree is also a self-contained operation in that it produces carbon anodes necessary to the aluminum reduction process. The facility is important to the Kentucky economy by employing 135 salaried workers and 360 hourly employees with a total annual payroll of $50 million including benefits. Typically, the smelter pays over $430,000 in property taxes, and $2 million to Kentucky in sales, use and other taxes. Our purchasing department buys approximately $17 million in goods and services from local merchants in the Henderson County area, and in 2010 we contributed $135,000 to local charitable and community organizations.

Q. How long has the smelter been in operation?

A. The smelter was built nearly forty years ago originally as a two line operation at an initial investment of $100 million. The decision to locate in Western Kentucky was made because of the availability of low cost power through Big Rivers. The ability to obtain low cost power continues to be the lifeblood of an aluminum smelter. Production commenced in 1972. The third potline was added in 1979 at an additional investment of $100 million. Since that time the smelter has invested additional capital including the projects I will later describe.

Q. How many smelters does Rio Tinto Alcan own in the United States?

A. Sebree is the only U.S. smelter owned by RTA, but RTA owns twenty-one smelters world-wide as well as other collateral businesses in the primary metals area. All twenty-one RTA smelters compete for investment funds so our productivity, which is highly dependent on the cost of power, is very important.

Q. Please describe the position of KIUC and the Sebree smelter in this proceeding.

A. My purpose is to give the Commission an understanding of the issues facing a U.S. smelter with a power contract having a high cost relative to other smelters. Given that reality and with the smelters facing further increases in the power cost, the KIUC proposal in this proceeding is intended to stabilize the existing smelter rate but without adversely affecting the rural ratepayers or Big Rivers, so that when the next downturn comes the smelter has a better chance of surviving and the economic damage to Western Kentucky from closure is avoided.

Q. Could you please elaborate?

A. Aluminum is produced and sold in a commodity market where the price is determined by global forces. The most significant component of producing aluminum is the cost of power. Sebree is currently paying Big Rivers $43.45 per megawatt hour for power which is one of the highest rates in the U.S. and certainly in the world outside China. At the time this testimony is filed, global forces are producing a relatively high market price for primary aluminum so that today the Sebree smelter has positive margins from operations. However, we know that those same global forces eventually will act in reverse and that the next downturn in aluminum prices will put the Sebree smelter at risk because of its high cost power supply. It is this increased risk that we want to avoid. Closure of one or both smelters would have a devastating impact on Western Kentucky. The impact would come from the loss of smelter and support industry jobs, the loss of taxes, and the rate increases that all remaining retail customers would face if Big Rivers could not resell the power at the prices or volumes that the smelters provide.

Q. Can a downturn be predicted?

A. No, because global forces of supply and demand do not lend themselves to accurate forecasting. Mr. Fayne has attached to his testimony a chart that traces the market price of aluminum on the LME since 1989 to show the cyclical nature of that market. We know a downturn is inevitable, so forward thinking at this stage is critical. Once the aluminum market moves downward, it is often too late for anyone to take corrective action.

Q. If a U.S. smelter, including Sebree, had to close part or all of its production, what is the likelihood that it would re-open in the near term?

A. The observed experience is that when U.S. smelters shut down, the closure is usually due to the power cost; and these smelters rarely restart and then only if they are able to obtain incentives intended to promote a restart. These incentives result in power rates closer to world averages. Recent history demonstrates that during the last wave of U.S. smelter closures in 2009, most closed indefinitely because they were not in line with world average power costs. If this occurred in Kentucky, the impact would not only be to the smelter but to the community as a whole. The direct and indirect effects would be substantial and would impact other customers, Big Rivers and the State itself.

Q. What will be the effect if the proposed rate increase to the smelters is approved?

A. At the current rate of $43.45 per megawatt hour, any U.S. smelter is at risk in the event of a downturn in aluminum prices. Increasing that power rate exacerbates that risk and makes it that much harder to remain open when the next down cycle comes. In the interim, the higher the rate, the harder it is for Sebree or any smelter to obtain funds for capital investment in the plant, and the absence of continuing investment puts the smelter at greater risk. Therefore if the proposed rate increase for the smelters is approved, it will make capital acquisition more difficult and it will leave the smelter more vulnerable in the next downturn.

Q. Mr. Leblanc, if the Sebree smelter is at risk now, it certainly was in mid-2009 when aluminum prices were lower and yet it still agreed to the current contract terms as part of the Unwind Transaction. Under the circumstances, why did Sebree agree to contract terms that you now say make it vulnerable in a cyclical downturn?

A. When I came to Sebree in 2008, I found that the plant's power supply was set to expire at the end of 2011. We would then have no source for a firm and complete supply other than from the wholesale power market. A smelter cannot operate long term on spot prices, and I was also told that a long term power contract, that is, power for more than five years, was not available for purchase at a price that would allow the smelter to operate, so the alternative for the smelter was uncertain at best if the Unwind Transaction did not work. Sebree supported the Unwind Transaction, which included short term compensation from E.ON U.S. and the ability to terminate on one year's notice, because it gave us the opportunity to extend the life of the smelter. It was the only practical solution to keep the plant running so we could hopefully find a long term solution.

Q. Has the Sebree smelter pursued other actions to maximize its long term viability?

A. Absolutely, because we have been aggressive in controlling non-power costs. Sebree has not remained idle in its quest to be efficient and to prosper – we have worked very hard over the years to reduce our operating costs. In 2009 we reduced annual costs by over 20% through more efficient use of manpower and other steps. In 2010 we were able to reduce the cost of casting remelt metal by 70%. In 2011 we are working to reduce our costs by a further 5%. In 2012 we are hoping to spend $16 million on equipment upgrades that would generate more production with same fixed cost which increases plant's viability. This is in addition to further working to reduce our operating cost.

Q. Can Sebree continue to cut non-energy costs in order to compensate for the high energy rate?

A. It is critical today for all business enterprises to think lean manufacturing. If a business is not focused on removing waste and increasing the efficiency of its processes, it is wasting money. So we are always looking for ways to reduce costs. However, it is not realistic that we can further reduce non-energy costs to the point of offsetting increasing power rates.

Q. Has the Sebree smelter been able to make capital investment in the plant?

A. Yes. In 2009 we invested $18 million in the first phase of our bake furnace upgrade. The second phase of the bake furnace is a $37 million project announced by the Governor in February 2011 and currently in progress.

Q. Why would Sebree be making such large capital investments if it is "at risk" in the event of another downturn?

A. These were all decisions made just to keep the plant operating efficiently. Without the bake furnace project, the smelter could not operate.

Q. What are other US Smelters doing to reduce power costs?

A. Most of the smelters still operating in the U.S. either have self-supply, special contracts or other regulatory treatments that keep costs low. These incentives are designed to retain large energy intensive industries that provide enormous economic returns for the citizens of that state. For example, Ormet in Ohio received $60 million in incentives each of the first two years of a ten year power contract to reduce its power cost. All of the recently announced U.S. smelter restarts, except for the restart of the fifth potline at Century Aluminum, have resulted from governmental or other actions that promote continuing aluminum smelter operations by minimizing electric power rates based on a recognition of the significant contribution of such smelters to local and statewide economies. Mr. Fayne has more detail on this point in his testimony.

Q. What is the long term goal for Sebree.

A. The goal is to be at the average point on the world-wide total cost curve, including power. We have already discussed reducing our cost, excluding power, by over 20% in 2009 and further in 2010 through the introduction of managing through lean processes. There are three objectives that can be achieved, if all stakeholders work together, by being at the average on the worldwide total cost curve including power.

1. By reducing our power cost we will create momentum to invest for the future and not just to survive.
2. We will be able to sustain the next downturn and not close.
3. If we can achieve 1 and 2 we can attract businesses around us to bring more jobs to Kentucky and consequently reduce the risk to all of Kentucky and the other rate payers. But if we are unable to show new businesses that the smelter is here for the long term, they won't come. They won't take the risk.

Q. Will accepting the KIUC proposal in this case assure the survival of Sebree?

A. The KIUC proposal in this case is an interim and necessary step that will stabilize the smelters' position as participants in the world-wide aluminum market, but ultimately in order for Sebree to be at the average total cost curve world wide a broader solution beyond the repetitious process of rate cases will be required. For the benefit of all the parties in the case, Big Rivers, the Members, the two smelters and other industrial customers, and the rural ratepayers, we need officials in the Commonwealth to come to grips with this problem and work with the parties to agree on a permanent solution.

Q. Do you have any further comment?

A. Yes. This case is not about reducing the power cost to make more money for the smelter or to disadvantage the rural ratepayers or Big Rivers. I want to be clear that today Sebree is making money because aluminum prices are relatively high. The Sebree smelter has been one of Western Kentucky's most important assets for four decades providing quality employment for generations. We are trying to secure its future. You cannot wait for the downturn to take corrective action. When a downturn comes, business decisions tend to be irrevocable so a plan to protect smelter viability and the jobs must be addressed now. To this end, what KIUC is proposing in this proceeding is a path that will create a new balance: improving the smelter's position on the cost curve, increasing its chances of surviving, and protecting the rural ratepayers and Big Rivers against the impact of smelter closure. This will make the smelters stronger which in turn will attract business and help invigorate the economy of Western Kentucky.

Q. Does that complete your testimony?

A. Yes.

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
KPSC CASE NO. 2011-00036

VERIFICATION OF STEPHANE LEBLANC

I, Stephane Leblanc, verify and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that the testimony is true and accurate to the best of my knowledge, information and belief.

Stephane Leblanc

COMMONWEALTH OF KENTUCKY
COUNTY OF HENDERSON

SUBSCRIBED AND SWORN TO before me by Stephane Leblanc this the 22 day of May, 2011.

Donna L. Freitag
Notary Public, Ky. State at Large
My Commission Expires 5/4/2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	CASE NO. 2011-00036
GENERAL ADJUSTMENT IN RATES	)	

DIRECT TESTIMONY AND EXHIBITS

OF

PAUL A. COOMES

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

MAY, 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	**CASE NO. 2011-00036**
GENERAL ADJUSTMENT IN RATES	)	

DIRECT TESTIMONY OF PAUL A. COOMES

Q. Please state your name, address, and profession.

A. My name is Paul A. Coomes. My address is 3604 Trail Ridge Road, Louisville KY 40241. I am a consulting economist. I have a Ph.D. in economics from the University of Texas. I am also a professor of economics at the University of Louisville.

Q. Have you testified before the Kentucky Public Utility Commission?

A. Yes, I have testified and submitted testimony several times before the Kentucky Public Service Commission to present studies I have performed for utilities, the Kentucky Industrial Utility Customers, Inc. ("KIUC") and Century Aluminum of Kentucky General Partnership and Rio Tinto Alcan ("Smelters").

Q. What is the purpose of your testimony?

A. I am providing testimony in support of a study that I conducted entitled, *The Estimated Economic and Fiscal Impacts of Kentucky's Two Aluminum Smelters (May 23, 2011).*

This study attempts to quantify the economic impact of Kentucky's two aluminum Smelters and the estimated impact on the Kentucky economy if the two Smelters were to curtail operations. This study is attached to my Direct Testimony as Attachment 1.

Q. What are the likely impacts on the Kentucky economy if the two Smelters curtailed operations?

There would be direct and indirect consequences to the Kentucky economy. The direct consequences would be the loss of the actual jobs at the two Smelters and the loss of the tax revenue provided by the Smelters and their employees. These direct losses are summarized in the table below:

Two Aluminum Smelter Plants in Western Kentucky, 2010		
	Direct Impacts	
1	Total jobs	1,207
2	Average annual pay per job	$60,448
3	Total annual wages and salaries	$72,960,643
4	Occupational taxes to Hancock and Henderson counties	$501,100
5	Kentucky state income taxes paid by employees	$3,575,865
6	Property and other taxes to Hancock and Henderson county governments	$374,633
7	Property and other taxes to Hancock and Henderson county public schools	$619,450
8	Property taxes to State of Kentucky	$871,168
9	Corporate income and license taxes, State of Kentucky	$350,000
10	Other taxes (fuel, sales, energy), State of Kentucky	$2,504,769
11	Subtotal: local governments in Kentucky	$1,495,183
12	Subtotal: Kentucky state government	$7,301,802
13	Total Kentucky state and local governments	$8,796,985

Source: RioTinto/Alcan and Century, except for Kentucky income tax, which is estimated by author.

As shown above, Kentucky would lose the approximately 1,200 jobs of the individuals that are directly employed by the Smelters. These individuals collectively earn approximately $73,000,000 in wages annually and over $116 million annually in wages, salaries, and benefits. These 1,200 jobs are highly prized manufacturing jobs. Average annual pay at the Rio Tinto and Century facilities is $60,000 per job. Company-provided benefits for health insurance, unemployment insurance, worker's compensation insurance, vacations, retirement, payroll taxes and the like boost this to over $96,000 per job. The companies and their employees pay about $7.3 million in taxes to Kentucky state government, and $1.5 million to county governments and local public school districts. State and local governments in Kentucky would lose nearly $9 million in annual tax revenue.

Q. Have you estimated the indirect impact on the Kentucky economy that would result if the two Smelters curtailed operations?

A. Yes, when we add the indirect impacts to the region and the Commonwealth to the analysis the impact is far more severe due to the inevitable loss of related jobs and commercial and retail jobs that are in place partly to serve smelter employees. Because the aluminum and related manufacturing operations serve primarily national and international markets, they bring new dollars into the regional economy. In this sense, a curtailment of the two Smelters would have large and predictable negative economic and fiscal impacts in western Kentucky. Curtailing the smelting operations would jeopardize the viability of related business activities, both upstream and downstream. Among the supporting industries that would be affected are river barges (that bring in alumina), engineering firms, maintenance contractors, trucking firms, and the other vendors to the smelting plants. Downstream, the Smelters supply raw aluminum to rolling and extruding mills in the region, which are clustered to support wire plants, auto parts plants, can factories, and other heavy aluminum users in the region. The Southwire Rod and Cable Mill, adjacent to the Hawesville smelter, could be in immediate jeopardy if the Smelters were to curtail, since its current business model depends upon the low costs associated with direct access to molten aluminum that meets its stringent purity specifications. These are just some of the businesses that would suffer if the Smelters were to curtail operations in Western Kentucky.

In the below table I provide estimates of the total effects – direct plus spinoff.

Estimated Total Annual Economic and Fiscal Impacts of Shut-down

Two Aluminum Smelter Plants in Western Kentucky

	Total: Direct, Indirect, and Induced Impacts	
1	Lost jobs in region	4,733
2	Lost annual payroll in region	$176,267,634
3	Lost property taxes - county governments	$374,633
4	Lost property taxes - schools	$619,450
5	Lost property taxes - Kentucky state government	$871,168
6	Lost occupational taxes - local governments	$501,100
7	Lost Kentucky state income tax receipts	$5,136,252
8	Lost Kentucky state sales tax receipts	$1,836,490
9	Lost other Kentucky state taxes	$2,854,769
10	Subtotal: local governments in Kentucky	$1,495,183
11	Subtotal: Kentucky state government	$10,698,679
12	Total Kentucky state and local governments	$12,193,862

The total net annual loss in the region would be 4,700 jobs and $176 million in wages and salaries. State and local governments in Kentucky would lose over $12 million annually.

The Southwire rod mill employs around 300 persons, with a payroll of about $12 million annually. Should it close, the additional negative economic impact in the region would be 850 jobs and $23 million in payroll. Kentucky state and local governments would lose at least an additional $1.4 million tax revenues annually.

Of course there would be many other negative impacts that cannot be reasonably estimated. Local real estate and retail markets would likely be depressed, unemployment and crime rates would rise, retraining and social services costs would increase, and many ancillary tax revenues would fall as economic activity in the region diminished.

Q. What would be the long-term impact on the region if the two Smelters were to curtail operations?

A. My study shows that the direct impact of curtailment of Smelter operations would result in the loss of about three quarters of a billion dollars in wages to the region (in 2010 dollars) over the next decade. The impact to local and state tax receipts would also be large. The Smelters represent over $88 million in taxes to Kentucky state and local governments over the next ten years.

When we add the indirect impacts to the region and the Commonwealth to the analysis the impact is far more severe. Over a ten year period the residents of Western Kentucky would lose approximately $1.75 billion in payroll and state and local governments would lose over $120 million in tax revenues.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

ATTACHMENT 1

OF

PAUL A. COOMES

The Estimated Economic and Fiscal Impacts of Kentucky's Two Aluminum Smelters

by
Paul A. Coomes, Ph.D.
Consulting Economist

a research report for
Century Aluminum and Rio Tinto Alcan

May 23, 2011

Executive Summary

Kentucky has two aluminum smelters, one near Hawesville and the other about fifty miles west at Sebree, near Henderson. These smelters are major employers and taxpayers in the greater Evansville-Owensboro-Henderson regional economy. Should electricity prices rise sufficiently these two plants could be closed, with relatively severe economic consequences for the region.

The smelters are owned by two companies: Century Aluminum (Hawesville) and Rio Tinto Alcan (Sebree). The companies are interested in learning about and documenting the regional economic importance of the operations, so they can better communicate the ramifications of rising electricity costs should prices reach a threshold such that the smelting operations were financially threatened. The purpose of this report is to document and communicate the regional economic and fiscal importance of these aluminum plants.

This report provides updates to my 2008 report on the same topic. The two Kentucky smelters together employ around 1,200 persons, who collectively earn over $116 million annually in wages, salaries, and benefits. I have used regional data and industry-specific multipliers to estimate the negative economic and fiscal impacts of such a possible shut-down. I estimate that the total net annual loss in the region would be 4,700 jobs and $176 million in wages and salaries. State and local governments in Kentucky would lose over $12 million annually. These estimates are for the economic and fiscal categories most easily quantified. There would be many other negative impacts, though they are harder to measure with any precision. Local real estate and retail markets would likely be depressed, unemployment and crime rates would rise, retraining and social services costs would increase, and many ancillary tax revenues would fall as economic activity in the region diminished.

Background and Methodology

There are two aluminum smelters in Kentucky, one operated by Century near Hawesville and the other by Rio Tinto Alcan at Sebree. Smelters can demand as much electricity load as a mid-sized city. With low cost power available to many new international aluminum smelters, the economic viability of these two Kentucky smelters depends critically on the cost of electricity. Shutting down the smeltering operations would jeopardize the viability of related business activities, both upstream and downstream. Among the supporting industries that would be affected are river barges (that bring in alumina), engineering firms, maintenance contractors, trucking firms, and the other vendors to the smelting plants. Downstream, the smelters supply raw aluminum to rolling and extruding mills in the region, which are clustered to support wire plants, auto parts plants, can factories, and other heavy aluminum users in the region. The Southwire Rod and Cable Mill, adjacent to the Hawesville smelter, could be immediately shut-down if the smelter were to close, since its current business model depends upon the low costs associated with immediate access to molten aluminum that meets its stringent purity specifications.

Population of Evansville IN-KY Economic Area, 2009

Geocodes	County	Residents
18051	Gibson, IN	32,750
18129	Posey, IN	26,004
18163	Vanderburgh, IN	175,434
18173	Warrick, IN	58,521
21010	Henderson, KY	45,496
21233	Webster, KY	13,706
21780	Evansville, IN-KY Metropolitan Statistical Area	351,911
21059	Daviess, KY	95,394
21091	Hancock, KY	8,635
21149	McLean, KY	9,607
36980	Owensboro, KY Metropolitan Statistical Area	113,636
17047	Edwards, IL	6,444
17059	Gallatin, IL	5,705
17185	Wabash, IL	11,997
17193	White, IL	14,661
18027	Daviess, IN	30,620
18037	Dubois, IN	41,419
18101	Martin, IN	13,070
18123	Perry, IN	18,812
18125	Pike, IN	12,259
18147	Spencer, IN	20,039
21107	Hopkins, KY	46,167
21177	Muhlenberg, KY	31,274
21183	Ohio, KY	23,534
21225	Union, KY	14,990
57054	Evansville, IN-KY Economic Area	756,538

Source: US Census Bureau

Geographic Scope of Impacts

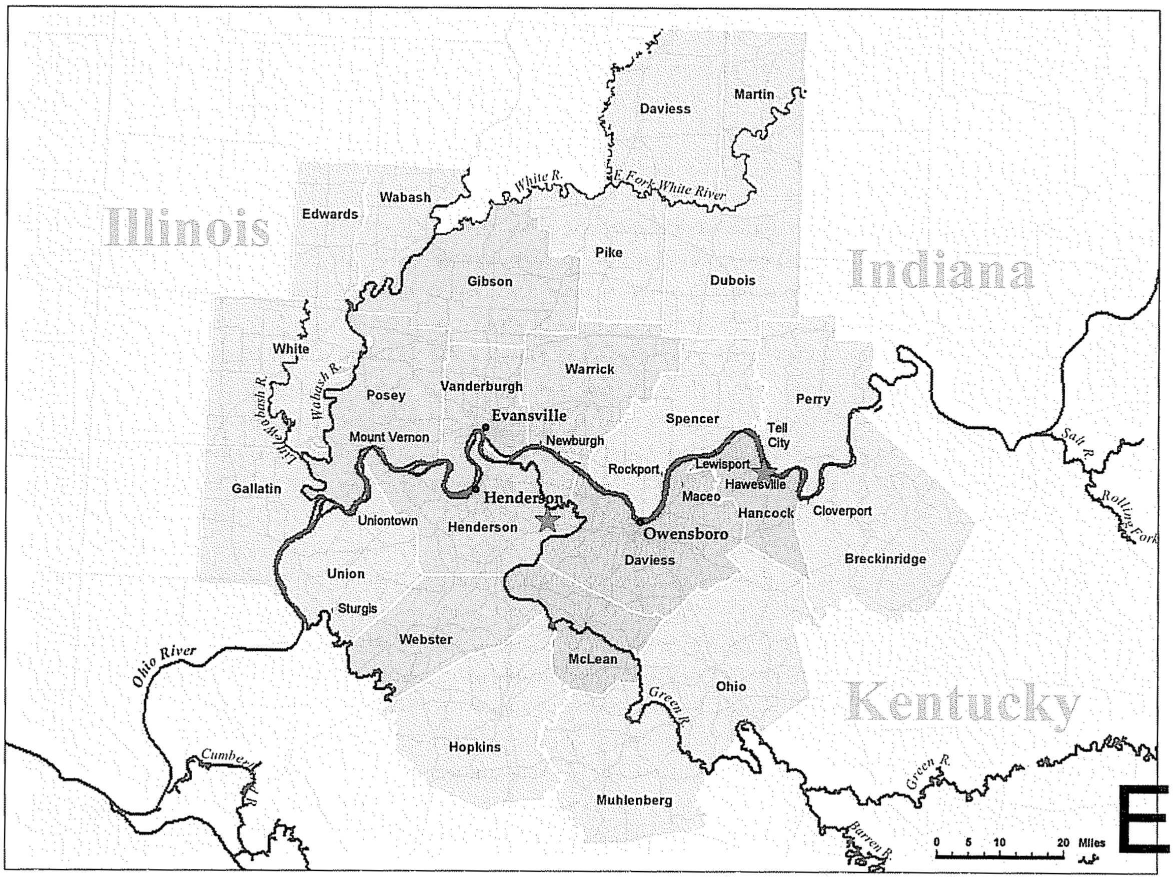
While Hancock and Henderson counties are the sites for the plants, the economic and fiscal impacts will permeate a much larger region. In this section, I discuss various geographic measures and explain how the choice of study impact region was made.

Both counties are part of the greater Evansville-Owensboro-Henderson Economic Area, a 23-county region in Kentucky, Indiana, and Illinois, as defined by the US Bureau of Economic Analysis[1]. The latest definitions for economic areas were released in 2004, and are based primarily on commuting patterns data from the 2000 Census. Hancock County is also part of the Owensboro MSA, a three county designation. Henderson County is part of the Evansville-Henderson MSA, a six county designation.

The map shows the component counties, major cities, road and water features in the economic area. The red stars denote the approximate position of the Century and Rio Tinto Alcan smelter plants. All the counties shaded in gray

[1] See US Bureau of Economic Analysis, www.bea.gov/regional/docs/econlist.cfm .

or green are part of the economic area, while those with the darker green shading are also part of the Evansville-Henderson or Owensboro Metropolitan Statistical Areas. The economic area classification was developed by the US Bureau of Economic Analysis, and assigns all US counties to some regional economy. This broader definition is very useful in analyzing the markets for labor, industrial supplies, major retail purchases, television and print media, air transportation, higher education, and major medical and professional services.



The latest population estimates are provided in the accompanying table. Note that the complete economic area has a population of about 757,000, with the Evansville-Henderson MSA accounting for 47 percent of the total, and the Owensboro MSA accounting for 15 percent of the total. Henderson County, just across the Ohio River from Evansville, has the fifth largest population of any county in the economic area. Hancock County has the third lowest population of any county.

The Evansville area also has a number of important aluminum operations, though it is beyond the scope of this study to analyze them. Warrick County, for example, is home to the giant

Alcoa plant upstream from Evansville on the Ohio River. The plant has 2,100 employees, pays over $7 million in local property taxes annually, and purchases over $100 million in goods and services from vendors in the region[2]. The region as a whole is one of the biggest concentrations of aluminum production and downstream processing in the US. The plants are linked indirectly through the transportation, energy, auto parts sectors that are prevalent regionally.

Importance to Hancock and Henderson counties, entire region

It is not hard to see in publicly available data how important aluminum is to the regional economy. In the next two tables, I have organized information on the largest industrial employers in Hancock and Henderson counties, as currently displayed on the web site of the Kentucky Cabinet for Economic Development[3]. I have highlighted in red the firms that produce or process aluminum. Note that in Hancock County three out of four of the top employers are aluminum-related. The Century smelter is the largest manufacturing employer in the County. Similarly, in Henderson County two of the top three manufacturing employers are aluminum-related. The Rio Tinto smelter is the third largest employer in Henderson County.

Largest Industrial Employers, Hancock County

Firm	Products	Employment	Date established
Century Aluminum of Kentucky LLC	Aluminum molten metal, sows & smelting	771	1967
Aleris Rolled Products	Coils, aluminum tubing & flexible conduits	603	1966
Domtar Paper Company LLC	Fine paper and mills bleach pulp	437	1967
Southwire Company Kentucky Plant	Aluminum rod and bare aluminum cable	317	1969
Dal-Tile Corp	Quarry tile	115	1959
First Class Services Inc		78	N/A
Precision Roll Grinders Inc	Roller repair & precision grinding	18	1998
Hancock County Ready Mix	Ready-mixed concrete	16	1964
Maxwell Brothers Lumber Co	Sawing rough lumber, cross ties, pallets	16	1984
McElroy Metal Inc	Metal forming, panel, trim, accessories	16	1964
Hancock County Ready-Mix	Sand & gravel, ready-mix concrete	15	1964

Source: Kentucky Economic Development Cabinet, August 2010 (www.thinkkentucky.com/edis/cmnty/cmntyindex.htm)

[2] See www.alcoa.com/locations/usa_warrick/en/pdf/2007ReportToTheCommunity.pdf

[3] Employment reported by the Kentucky Economic Development Cabinet for the Century and Rio Tinto Alcan plants will differ somewhat from the corporate counts in this report due to the different reference dates.

Largest Industrial Employers, Henderson County

Firm	Products	Employment	Date established
Tyson Foods Inc	Chicken slaughtering, processing & packaging	930	1995
Gibbs Die Casting Corp	Aluminum & magnesium die castings, headquarters	800	1966
Rio Tinto Alcan	Aluminum extrusion billets & ingots	488	1972
Dana Corporation	Truck axles & brake components	250	1970
Accuride Corp	Truck wheels & rims	234	1973
Brenntag Mid-South Inc	Chemical blending, industrial chemical distribution	228	1947
Audubon Metals LLC	Heavy-media separator and secondary specification aluminum alloy	150	1996
Columbia Sportswear Company	Storage and distribution of footwear and apparel products	130	2004
Sitex Corporation	Headquarters and uniform supply service	124	1961
Sonoco	Aluminum & steel can ends	120	1967
Hercules Manufacturing Co	Insulated & dry freight truck bodies & trailers	100	1902
Hugh E Sandefur Training Center Inc	Voc rehab; corrugated products; boxes, partitions, die cuts.	100	1967
Service Tool & Plastics	Injection molded plastics	99	1977
International Paper	Recycled linerboard	75	1994
Azteca Milliing LP	Milled Mexican corn flour	72	1988
Cresline Plastic Pipe Co Inc	Plastic pipe & fittings	68	1966
Royster's Machine Shop LLC	Machine shop: general & CNC machining,	66	1975
Fortis Plastics LLC	Thermoplastics & plastic injection molding, finishing, fabricating	61	1951
Shamrock Technologies Inc	Teflon recycling, micronized polytetrafluoroethylene	61	1997
SGS North American Inc Mineral	Analytical coal testing	60	1809

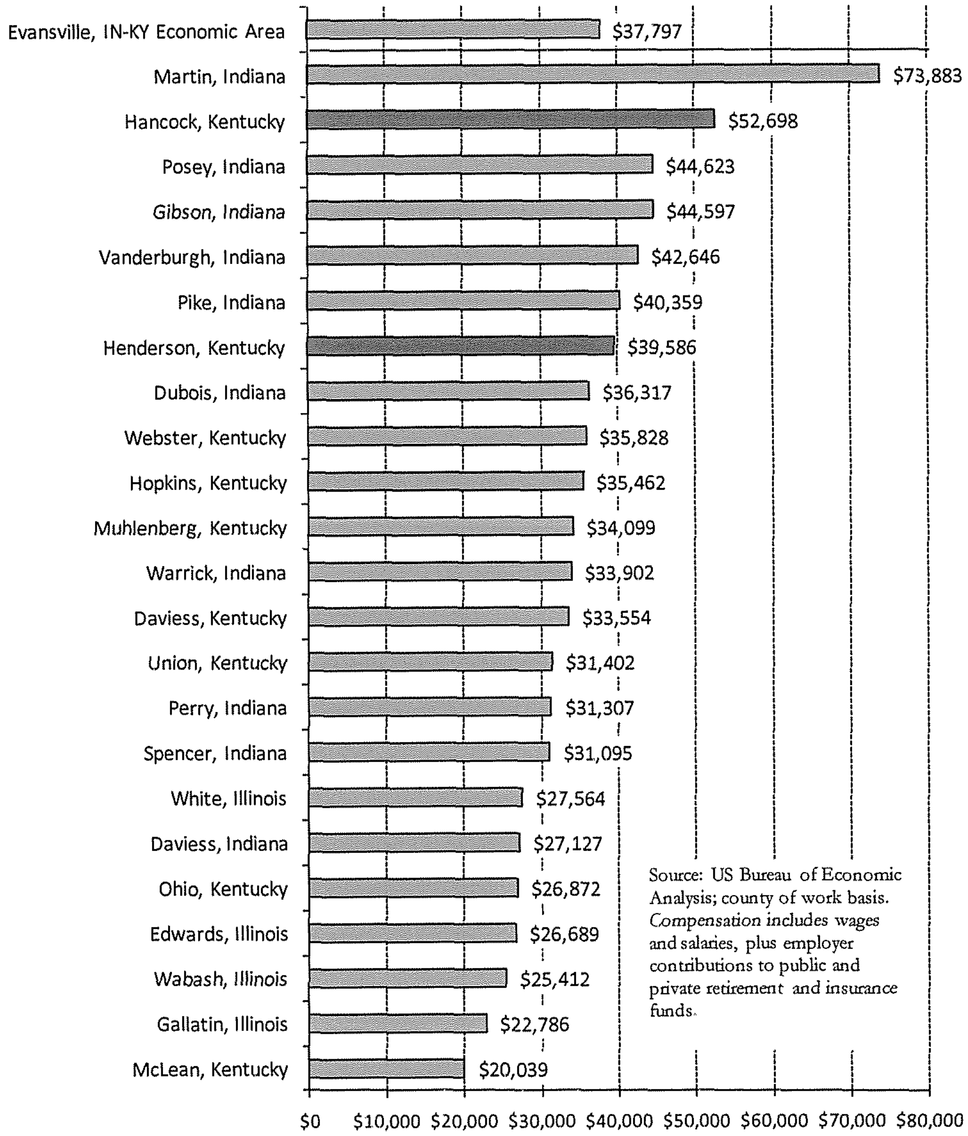
Source: Kentucky Cabinet for Economic Development (8/15/2010).

There are about 372,000 private sector jobs in the region, of which 68,000 are in the manufacturing sector. Due to confidentiality laws, the federal statistical agencies do not disclose enough data to accurately measure the total aluminum-related employment and payroll in the region. But, using publicly available estimates on aluminum production employment, including Alcoa in Warrick County, and the aluminum fabrication companies in Hancock and Henderson counties, we can see that at least 4,800 of the region's manufacturing jobs are directly related to aluminum. Clearly, aluminum production and processing are critical to the health of the regional economy.

Moreover, the two smelter operations are crucial components of the tax and economic base in Hancock and Henderson counties. The Century operation in Hawesville accounts for 21 percent of all private sector wages and salaries earned in Hancock County, and directly accounts for about 19 percent of the total county's occupational tax receipts. The Hawesville plant also accounts for about six percent of all property taxes collected to support the Hancock County Public School system. The Rio Tinto Alcan operation accounts for over five percent of private wages and salaries in (much more populated) Henderson County, and over 2 percent of all property and utility taxes collected for public schools and county government. Rio Tinto is believed to be the largest single taxpayer in Henderson County.

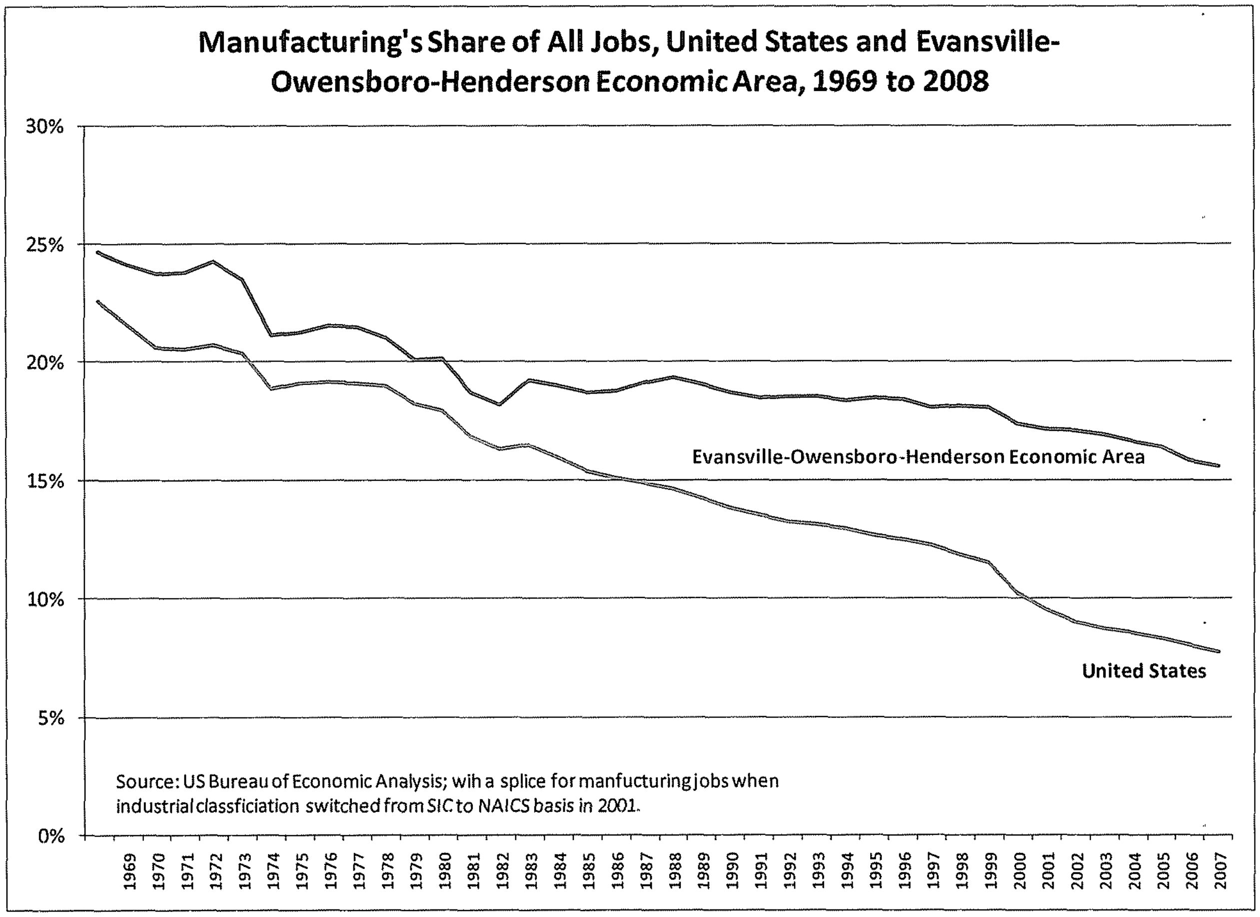
The importance of the aluminum-related jobs in the region stems from (a) their large number, (b) their linkages to other jobs in upstream and downstream industries, and (c) their high average pay and benefits. Average pay at the Rio Tinto and Century facilities is $60,000 per job. Company-provided benefits for health insurance, unemployment insurance, worker's compensation insurance, vacations, retirement, payroll taxes and the like boost this to over $96,000 per job.

Average Annual Compensation per Job, 2008
Evansville-Owensboro-Henderson Economic Area



The concentration of many such aluminum-related jobs in Hancock and Henderson counties puts those two in the top third in the region in terms of earnings per job. The relationship is particularly easy to see in Hancock County, as the county is lightly populated and aluminum is the most important industry. At $52,698, Hancock is second highest among counties in the region in terms of total compensation per job. Henderson County ranks seventh among the 23 counties in terms of compensation per job. Warrick County, home to the large Alcoa smelter and electricity plant, ranks twelfth highest.

Manufacturing has long been of great economic importance in the region. There has been a steady decline for decades nationally in manufacturing's share of jobs, including in the Evansville area economy. The trend is due to increased productivity, as technological developments in machinery have allowed each worker to produce much more output. But the decline in employment has been much less severe in the region. While manufacturing today accounts for only 7.8 percent of jobs nationally, in the Evansville region the share is twice that, at 15.6 percent.



This relatively high concentration of manufacturing jobs in the Evansville-Owensboro-Henderson Economic Area, along with its high labor compensation, has kept per capita income in the region from falling behind nearby economic areas, even though there has been only modest overall population and job growth. In the next table, I have organized data on 40 years of growth for four macro performance indicators. I compare growth in the Evansville area to that of all 180 economic areas in the US, as well as those nearest – Indianapolis, Evansville, Paducah, St. Louis, and Champaign. While the Evansville area ranked low in terms of population and job growth overall, it ranks well in terms of average earnings per job, which in turn improves its ranking for per capita income. Clearly, the manufacturing strength in the region has been the key factor in maintaining the standard of living for residents there. Aluminum production and fabrication have been a major part of that manufacturing strength throughout the period.

Macro Economic Indicators of Growth*, 1969 to 2008

	Evansville, IN-KY-IL Economic Area	rank among all 180 Economic Areas	rank among 6 nearest Economic Areas
Population	0.4%	135	4
Jobs	1.0%	147	5
Average earnings per job	5.0%	97	2
Per capita income	6.2%	118	2

Source: US Bureau of Economic Analysis, with rankings by author.
* compound average annual growth rate

Economic Impact Methodology
Because the aluminum and related manufacturing operations serve primarily national and international markets, they bring new dollars into the regional economy. In this sense, a shut-down of the two smelters would have large and predictable negative economic and fiscal impacts in western Kentucky, southern Indiana and throughout the two states. The activity supports thousands of jobs and millions of dollars in payrolls, and ultimately large tax revenues for Kentucky and Indiana state and local governments.

I use standard regional economic impact methods to evaluate the economic and fiscal impacts of the loss of the two plants. Region-specific economic impacts were derived from a custom input-output model built for the Evansville-Owensboro-Henderson economic area, discussed further below. The model includes detailed information on 440 industries in the region, including primary aluminum production. This industry is defined according to the North American Industrial Classification System (NAICS) code 331312. The official definition is as follows:

> This U.S. industry comprises establishments primarily engaged in (1) making aluminum from alumina and/or (2) making aluminum from alumina and rolling,

drawing, extruding, or casting the aluminum they make into primary forms (e.g., bar, billet, ingot, plate, rod, sheet, strip). Establishments in this industry may make primary aluminum or aluminum-based alloys from alumina.

www.census.gov/epcd/naics02/def/ND331312.HTM#N331312

I have constructed a custom regional input-output model, using the IMPLAN system. The IMPLAN model provides a representation of the linkages among 440 regional industries, as well as spending patterns of area households[4]. The regional model used here is derived from the national input-output transactions tables, using detailed data on local industries. Regional input-output models are the most common tool used to evaluate economic impacts of industries and events. These models provide consistent and unbiased estimates of the ripple effects in a region when there is a change in activity at any other industry. These impacts are often summarized using economic multipliers, which are the ratio of changes in total economic impacts to a change in direct activity in an industry. Their strengths and weaknesses are well-known, and I believe this model is the best tool available to analyze the impacts of a plant shutdown.

Regional economists often make the distinction between the indirect and induced components of a multiplier, and in some cases make separate estimates for each. The indirect effects refer to the linkages between the exporting industry (aluminum) and their industrial vendors (electricity, barges, tools, computers, insurance). When the directly impacted industry expands it raises its purchases from its vendors, thus lifting their employment and payrolls. The induced effects refer to the impact of the new export-based sales on the local economy through the rounds of re-spending of the additional consumer income caused by the expansion. Regional sales of cars, groceries, building supplies, banking services, and so on are all sensitive to growth

Economic Multipliers for the Primary Aluminum Industry

Evansville-Owensboro-Henderson Economic Area

	Indirect effects: inter-industry expenditures	Total effects: indirect plus induced (household spending) effects
Employment	2.753	3.921
Employee compensation	2.062	2.416
Output	1.628	1.768
Value added	2.429	2.861

Source: regional input-output model of region, using IMPLAN version 3.

Multipliers shown measure the total impact in the region per one unit increase in economic category. For example, in the first row, an additional job in the aluminum industry leads to a totral of 3.921 jobs in the regional economy, of which 2.753 jobs area due to inter-industry purchases.

[4] See www.implan.com for documentation.

in disposable income. In the final impact estimates, I use the total multipliers for the regional aluminum industry, those that summarize both the indirect and induced effects on the economy.

The economic multipliers shown in the table summarize the predicted impacts on the region for a change in the aluminum industry. Economic multipliers derived from input-output models are symmetric. That is, one gets the same proportional economic impact from an increase or a decrease in activity at a local industry. For example, the employee compensation multiplier for the primary aluminum production industry in the Evansville-Henderson-Owensboro economic area is 2.416, meaning that for every dollar of new export-based payroll created at a local aluminum smelter another $1.416 in payrolls are created in other sectors around the region. The job multiplier for the primary aluminum sector in the area is 3.921, meaning that for every new export-based job created at a smelter, another 2.921 jobs are created elsewhere in the region.

The output multiplier is a measure of the additional sales by firms in the region related to primary aluminum production. Finally, for completeness, we show the value added multiplier for the aluminum industry. Value added is a term used in economic accounting to distinguish between the total value of output (sales) and the dollars that stick to the local economy. It measures the regional payments to labor, capital, and land in return for producing the output sold regionally. This can be an important distinction. For example, if someone purchases a new Volkswagen automobile for $20,000 at a local dealership, probably no more $2-3,000 gets captured in the regional economy, with the bulk going to the auto manufacturing plant in another state, to transportation expenses, to the corporate headquarters staff, and to shareholders. By contrast, most of the $15 one might pay for a haircut gets captured locally, to pay the barber and the rent, utilities, and taxes on the barber shop.

There are no good national sources of data on which to make estimates of the fiscal impacts of a regional expansion or contraction. However, there are plentiful data available from state and local governments. I have compiled several years of tax receipts data from Kentucky and Indiana state governments, as well as tax information from city and county governments in the region. By comparing the growth in tax receipts to the growth in payrolls historically, I calculate 'effective' tax rates and use those to estimate the loss of income, sales, and occupational taxes due to the simulated loss of aluminum industry payrolls. The tax calculations are discussed in more detail in the next section and in an appendix to this report. Next we turn to a discussion of geographic issues.

Taxes and fiscal impacts

The plants generate an array of taxes for state and local governments. The value of real estate and tangible property is quite large, and thus the plants generate substantial property taxes for the state of Kentucky and Hancock and Henderson county governments, including the two county public school systems. The workers associated with the plant spend much of their income in the regional economy, generating state income, state sales, and local occupational taxes. I provide estimates of all these tax flows below.

Additional tax impacts are also likely, though much harder to quantify. For example, proprietors and corporations around the region will be liable for state individual and corporate income taxes, and for some 'net profits' taxes in cities and counties where these are levied, e.g., the City of Owensboro, Kentucky. Gasoline taxes, coal severance taxes, unemployment insurance taxes, insurance premiums taxes, building permit fees, motor vehicle sales taxes, and many other business tax categories would see some decline due to plant shut-downs. Employees would pay less in the way of gasoline taxes, motor vehicle sales taxes, and there would be dampening effect on the regional real estate market. These categories are much harder to measure than the income and general sales taxes, but fortunately are not as important dollar-wise as the main taxes I do measure in this report.

Estimates of new Kentucky and Indiana state individual income and sales tax revenues are calculated by multiplying effective tax rates times the new regional payrolls. The ratios of state individual income taxes or sales taxes collected to wages and salaries are very stable historically. Using these ratios, or effective tax rates, is superior to using published nominal tax rates, as the amount of income or sales subject to taxation is always less than total income received and retail spending that occurs.

For example, groceries and prescription drugs are exempt from state sales tax in Kentucky, and hence one cannot simply multiply the statutory sales tax rate of six percent times expected retail sales. Similarly, individual income tax rates apply to 'adjusted gross income' or 'taxable income', rather than total income. In Kentucky, residents can deduct such things as medical expenses, mortgage interest payments, charitable contributions, and many other items from their gross income before calculating their tax liability. Looking at historical tax collections as a percentage of payrolls is a more reliable way to estimate the amount of taxes likely to be generated from future payroll growth. An appendix provides a summary of the effective tax rate calculations used in the impact assessment.

Estimated Impacts

In this section, I display and explain my estimates of the economic and fiscal impacts of the two aluminum smelters. I am essentially simulating what would happen if the two operations were removed from the region. In the first table, I organize data and estimates of the direct impacts of the two plants. That is, I am considering only the jobs, taxable payrolls and taxes paid by the operations, and am not yet considering any spinoff effects in the regional economy.

Two Aluminum Smelter Plants in Western Kentucky, 2010

Direct Impacts

1	Total jobs	1,207
2	Average annual pay per job	$60,448
3	Total annual wages and salaries	$72,960,643
4	Occupational taxes to Hancock and Henderson counties	$501,100
5	Kentucky state income taxes paid by employees	$3,575,865
6	Property and other taxes to Hancock and Henderson county governments	$374,633
7	Property and other taxes to Hancock and Henderson county public schools	$619,450
8	Property taxes to State of Kentucky	$871,168
9	Corporate income and license taxes, State of Kentucky	$350,000
10	Other taxes (fuel, sales, energy), State of Kentucky	$2,504,769
11	Subtotal: local governments in Kentucky	$1,495,183
12	Subtotal: Kentucky state government	$7,301,802
13	Total Kentucky state and local governments	$8,796,985

Source: RioTinto/Alcan and Century, except for Kentucky income tax, which is estimated by author.

The plants employ over 1,200 persons and have a combined annual payroll of about $73 million, excluding benefits. The companies and their employees pay about $7.3 million in taxes to Kentucky state government, and $1.5 million to county governments and local public school districts. All the entries except that on line 5 were provided by the two companies that own and operate the smelters. The companies do not know the amount of Kentucky state income taxes actually paid by their employees, since employees file income tax returns from their place of residence. Companies do withhold state income taxes from workers paychecks, but have no way of knowing how much additional tax employees end up paying, or how big of a tax refund they receive each year. To estimate the Kentucky state income taxes paid, I applied an effective income tax rate, one that was calculated by dividing Kentucky state income taxes paid by Kentucky wages and salaries earned. The rate is 4.90 percent of payrolls.

In the second table, I provide estimates of the total effects – direct plus spinoff. Here I use the economic multipliers to estimate the loss in jobs and payrolls regionally. Then I use effective tax rates to estimate the additional loss in income and sales taxes to Kentucky state government. These fiscal impacts include an estimate of the state income and sales taxes related to spinoff payroll, not just that from the plant operations.

Estimated Total Annual Economic and Fiscal Impacts of Shut-down

Two Aluminum Smelter Plants in Western Kentucky

	Total: Direct, Indirect, and Induced Impacts	
1	Lost jobs in region	4,733
2	Lost annual payroll in region	$176,267,634
3	Lost property taxes - county governments	$374,633
4	Lost property taxes - schools	$619,450
5	Lost property taxes - Kentucky state government	$871,168
6	Lost occupational taxes - local governments	$501,100
7	Lost Kentucky state income tax receipts	$5,136,252
8	Lost Kentucky state sales tax receipts	$1,836,490
9	Lost other Kentucky state taxes	$2,854,769
10	Subtotal: local governments in Kentucky	$1,495,183
11	Subtotal: Kentucky state government	$10,698,679
12	Total Kentucky state and local governments	$12,193,862

I estimate the total job loss in the region to be about 4,700 jobs, and the payroll loss to be $176 million annually. The total loss to Kentucky state government is much more than when considering only the direct impacts. I estimate that Kentucky would lose a total of $12.2 million in income, sales and other tax revenues if the plants shut down. The reader might note that the total estimated payroll impact is 2.4 times the direct payroll impact, while the total estimated fiscal impact is only 1.4 times the direct fiscal impact. This is because the direct fiscal impact includes many non-payroll items, including property and corporate income taxes. I do not attempt to estimate any indirect and induced tax impacts beyond the state individual income and sales taxes linked to more regional payroll.

The Southwire rod mill employs around 300 persons, with a payroll of about $12 million annually. Should it also close, the additional negative economic impact in the region would be 850 jobs and $23 million in payroll. Kentucky state and local governments would lose at least an additional $1.4 million tax revenues annually.

References

Kentucky Cabinet for Economic Development, "Profile of the Aluminum Industry in Kentucky", by Rene True, May 2005. www.thinkkentucky.com/kyedc/pdfs/Aluminum_Report.pdf

Minnesota Implan Group, MIG, www.implan.com

APPENDIX
State Individual Income and Sales Tax Revenues

I have calculated effective tax rates for both Kentucky and Indiana income and sales taxes, summarized in the table on the next page. I show these in two ways, one as a percentage of total regional wages and salaries, and second as a percentage of just the wages and salaries earned in each state. The effective state tax rate is obviously much smaller when the entire regional payroll is considered, since each state makes up only a fraction of the region. In the fiscal impact estimates provided, I use these state effective tax rates calculated as a percentage of the total regional payroll. Since the economic multiplier effects are analyzed over the entire 23-county economic area, we see the effect of the aluminum operations on wages and salaries throughout the region. Hence, the regional effective tax rates are more applicable.

Note that the Kentucky effective income tax rate is 1.51 percent. This means that Kentucky state government can expect to receive (lose) in income taxes that percentage of wages and salaries *in the region* when payrolls grow (shrink). Similarly, the Kentucky effective sales tax rate is 1.04 percent of wages and salaries in the region. The regional effective tax rates for Indiana state government are higher than for Kentucky state government, reflecting the higher proportion of payrolls, income taxes, and sales taxes on the Indiana side of the regional economy. The Kentucky effective income tax rate is higher than the effective sales tax rate, while in Indiana the effective sales tax rate is higher than the effective income tax rate. This reflects both Kentucky's higher income tax rate (topping at 6% compared to Indiana's which tops out at 3.4%), and the concentration of retail activity in Evansville.

County	Wages and Salaries, by County of Work	State individual Income Taxes Paid, by County of Residence	State Sales Taxes Paid, by County of Collection
	Average Annual Wages and Salaries, and State Tax Receipts, by County, 2005 to 2008		
Edwards, Illinois	$94,180,750		
Gallatin, Illinois	$48,229,500		
Wabash, Illinois	$114,508,250		
White, Illinois	$160,085,000		
Daviess, Indiana	$349,720,750	$15,604,546	$19,217,452
Dubois, Indiana	$1,017,137,250	$32,720,178	$46,637,774
Gibson, Indiana	$740,795,750	$20,220,337	$8,740,361
Martin, Indiana	$388,755,250	$5,650,547	$4,947,782
Perry, Indiana	$219,496,000	$10,319,579	$12,107,029
Pike, Indiana	$126,917,750	$7,386,286	$1,399,167
Posey, Indiana	$434,829,500	$19,122,831	$12,314,706
Spencer, Indiana	$250,206,750	$12,484,294	$7,333,808
Vanderburgh, Indiana	$4,275,895,250	$118,534,579	$190,451,240
Warrick, Indiana	$567,881,500	$47,714,466	$8,338,172
Daviess, Kentucky	$1,453,203,500	$70,446,207	$60,545,673
Hancock, Kentucky	$208,735,750	$5,919,378	$3,514,191
Henderson, Kentucky	$721,062,000	$31,219,230	$24,930,991
Hopkins, Kentucky	$625,859,750	$31,988,133	$18,644,412
McLean, Kentucky	$49,044,000	$5,944,519	$2,449,612
Muhlenberg, Kentucky	$319,666,000	$15,895,804	$9,922,632
Ohio, Kentucky	$207,207,000	$11,115,268	$5,018,780
Union, Kentucky	$185,568,000	$10,198,584	$4,798,603
Webster, Kentucky	$144,737,000	$9,154,535	$2,532,127
Evansville, IN-KY Economic Area	$12,703,722,250	$481,639,301	$443,844,510
Kentucky subtotal - 9 counties	$3,915,083,000	$191,881,657	$132,357,023
Indiana subtotal - 10 counties	$8,371,635,750	$289,757,643	$311,487,488

Kentucky effective tax rate, collections as percent of Economic Area payroll		*1.51%*	*1.04%*
Kentucky effective tax rate, collections as percent of KY payroll		*4.90%*	*3.38%*
Indiana effective tax rate, collections as percent of Economic Area payroll		*2.28%*	*2.45%*
Indiana effective tax rate, collections as percent of IN payroll		*3.46%*	*3.72%*

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of: The Application Of Big Rivers Corporation For General Adjustment of Rates.	:	Case No. 2011-00036

AFFIDAVIT OF PAUL COOMES

STATE OF KENTUCKY (COUNTY OF JEFFERSON)

Paul Coomes being first duly sworn, deposes and states that:

1. He is a consulting economist and Professor of Economics at the University of Louisville;

2. He is the witness who sponsors the accompanying testimony entitled "Direct Testimony and Exhibits of Paul A. Coomes;"

3. Said testimony was prepared by him and under his direction and supervision;

4. If inquiries were made as to the facts and schedules in said testimony he would respond as therein set forth; and

5. The aforesaid testimony and schedules are true and correct to the best of his knowledge, information and belief.

Paul A. Coomes

Paul A. Coomes

Subscribed and sworn to or affirmed before me this 23 day of May, 2011, by Paul Coomes.

Carla L. Tidd

Notary Public

CARLA L. TIDD
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
MY COMMISSION EXPIRES DECEMBER 02, 2014

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	**)**	
Corporation for a General Adjustment	**)**	
In Rates	**)**	**Case No. 2011-00036**

DIRECT TESTIMONY

OF

GENE STRONG

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

MAY 2011

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of: The Application Of Big Rivers Corporation For General Adjustment of Rates	:	Case No. 2011-00036

DIRECT TESTIMONY OF GENE STRONG

Q. Please state your name and business address.

A. My name is Gene Strong and I am a partner and co-founder of McCarty-Strong Global, LLC, a business development and consulting firm based in Lexington, Kentucky. My business address is 444 East Main Street, Suite 102, Lexington, Kentucky.

Q. Please state your educational background and work experience.

A. For fourteen years from 1993 to 2007 I served as Secretary of the Kentucky Cabinet for Economic Development under the Jones, Patton and Fletcher administrations. I also served as Deputy Secretary from December, 1991 to March, 1993. For eleven years prior to my service to the Commonwealth I was with a national real estate development company based in Lexington where I was a partner and Executive Vice President. My responsibilities for that company included marketing and negotiating office and industrial real estate transactions throughout the United States. I am a 1974 graduate of Eastern Kentucky University with a Bachelor's Degree in Business Administration.

Q. Please describe your responsibilities as Secretary of the Cabinet for Economic Development?

A. The mission of the Cabinet was and is to direct the operations of the primary state agency in Kentucky responsible for creating new jobs and investment in the Commonwealth and working with existing business partners to reinvest and grow in the Commonwealth. Both business attraction and business retention are critical to growing the state's economy. My responsibility was to lead that mission.

Q. Can you describe generally the success of the Cabinet in creating new jobs and attracting new industry to Kentucky during your tenure?

A. Yes. While I was Secretary more than 274,500 new manufacturing and supportive industry jobs were created in the Commonwealth, and total estimated capital investment increased by more than $35 billion. During this period Kentucky was consistently ranked as one of the top ten states in new job creation, investment and business retention.

Q. Are you testifying in favor of the KIUC position in this case?

A. No. The purpose of my testimony is not to support the specific rate proposals of either Big Rivers or KIUC. I was asked by the smelters if I would describe for the

Commission, based on my experience in economic development, how or if the smelter payroll and investment could be easily replaced if either or both smelters could no longer operate for whatever reason, so my testimony is restricted to what the Commonwealth and its citizens would face in trying to replace the smelters if they closed. I was in economic development for a long time and in my opinion, it would be extremely difficult and perhaps impossible to replace these companies and the high paying jobs they offer to Kentucky citizens. I would recommend that the Commission do everything it can with respect to smelter power costs so those jobs and that investment are retained and not lost due to the cost of power.

Q. Are you familiar with the Hawesville and Sebree aluminum smelters?

A. Yes. Both smelters are major manufacturing facilities critical to the economy of Western Kentucky. During my tenure as Secretary, the Cabinet operated a regional office in Madisonville devoted exclusively to business retention, and I and other Cabinet representatives would visit them periodically. I also have asked for updated information from the companies and have read the testimony filed in this case by Dr. Paul Coomes.

Q. Is it true that Kentucky is in competition with other states in the recruitment of new industry and the retention of existing industry?

A. Yes. All states have incentive programs designed to bring in new jobs or to expand existing manufacturing facilities.

Q. Mr. Strong, since 274,500 new jobs were created during your tenure as Secretary of Economic Development, it would appear that losing 500 or even 1,000 smelter jobs would not be that severe.

A. That is certainly not correct. The Alcan smelter at Sebree and the Century smelter at Hawesville are manufacturing facilities that produce high paying jobs and bring additional capital investment to Kentucky. In my opinion it would be virtually impossible to replace those jobs should the facilities have to close, especially under current economic circumstances.

Q. Would you please elaborate?

A. Yes. I believe it is reasonable to look at Henderson County as a frame of reference. I have been advised by Alcan that the average level of annual salary, including benefits at the Sebree smelter is $100,000 for all workers and $ 87,000 for hourly workers and that the benefit level is approximately 30%. On that basis the average annual salary for all workers at Sebree would be $70,000 and $61,000 for hourly workers. This compares to the 2010 average annual salary in Henderson County for manufacturing jobs, excluding benefits, of $42,999 and $47,996 for Kentucky as a whole. Another view is weekly wages in Henderson County manufacturing jobs. In 2009 the average weekly wage was $812 in Henderson County and $923 for all of Kentucky, compared to $1,173 for hourly workers at Sebree and $1,345 all workers. Another comparable statistic is average disposable income which in Henderson County in 2008 was $31,265. So when you compare the compensation levels at Sebree with the rest of Henderson County, you can appreciate how valuable the smelter jobs are.

Q. During your tenure as Secretary of Economic Development, how many companies with a workforce and salary-benefit level comparable to the smelters was the Cabinet able to attract to Kentucky?

A. Very few. These jobs would certainly be among the top 10% in terms of wage levels. I would add that there are more jobs at the Sebree smelter than have been created in the manufacturing segment in Henderson County over the last ten years. The Cabinet database shows that there has been only one new manufacturing facility located in Henderson County since 2008 with 20 jobs. From 2001 to 2008 only two major additions have located in Henderson County with a total of 182 employees.

Q. How many manufacturing jobs are there in Henderson County?

A. The Cabinet data base for 2009 shows a total of 4,278 manufacturing jobs. This means that if you lost the jobs at Sebree, it would eliminate over 11% of the manufacturing workforce in the County. This on top of a 10.2% unemployment rate would not paint a very pretty picture.

Q. How do manufacturing jobs compare with other sectors in terms of investment?

A. There is typically greater continuing investment with manufacturing facilities because capital additions are usually necessary for the improvement and maintenance of the manufacturing process. I have been advised that the Sebree smelter is in the middle of a $37 million capital expansion project and, in addition, typically spends another $9 million a year on capital maintenance and replacements. In comparison, the one new manufacturing development in Henderson County since 2008 represented an investment of $1 million. In the same period there have been 17 manufacturing expansions in Henderson County, excluding the Sebree smelter, with a total investment of $30 million or approximately $1.8 million for each company. Again, you can see that the Sebree facility compares favorably with other manufacturing facilities in terms of continuing investment.

Q. Mr. Strong, do you have an opinion on how long it would take to replace the high paying jobs at Sebree if the smelter were to close?

A. This would be in the area of conjecture, but based on my experience and the track record as we know it, I would say it would be many, many years, if ever.

Q. Does that complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	)	
Corporation for a General Adjustment	)	
In Rates	)	Case No. 2011-00036

DIRECT TESTIMONY

AND EXHIBITS

OF

DR. MATHEW J. MOREY

ON BEHALF OF THE
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC
MADISON, WISCONSIN

MAY 23, 2011

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	)	
Corporation for a General	)	
Adjustment In Rates	)	**Case No. 2011-00036**

DIRECT TESTIMONY OF DR. MATHEW J. MOREY

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, YOUR POSITION, AND THE NAME OF THE FIRM THAT EMPLOYS YOU, ALONG WITH ITS BUSINESS ADDRESS.

A. My name is Mathew J. Morey. I am a Senior Consultant with Christensen Associates Energy Consulting, LLC, 800 University Bay Drive, Suite 400, Madison, Wisconsin.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Kentucky Industrial Utility Customers, Inc. (KIUC). KIUC is representing Alcan Primary Products Corporation, Century Aluminum of Kentucky (Smelters), Domtar Paper, Kimberly Clark and Aleris International.

Q. PLEASE SUMMARIZE YOUR PROFESSSIONAL BACKGROUND.

A. I received my doctorate in economics and statistics from the University of Illinois in 1977, and taught economics and econometrics for nearly twenty years. During that time, I also worked as a consultant to companies in and regulators of the telephone, natural gas, and electricity industries. I served as Director of Economics at the Edison Electric Institute from 1996 to 2000. Prior to joining Christensen Associates in 2003, I was an independent consultant to companies in the electricity industry both in the U.S. and Canada.

I have testified before state and federal regulatory agencies, including the Federal Energy Regulatory Commission, on a wide range of electric industry issues including stranded costs, market power, seams elimination cost adjustment charges, utility codes of conduct, utility affiliate transfer pricing rules, distribution standby and transmission rate design, the costs and benefits of membership in Regional Transmission Organizations (RTOs), and the economic advantages and disadvantages of independent coordinators of transmission. A complete list of my appearances is provided in Exhibit MJM-1.

I have testified before the Commonwealth of Kentucky Public Service Commission (Commission) in Case No. 2003-00266, in which Louisville Gas & Electric Company and Kentucky Utilities Company sought the Commission's authorization to exit the Midwest Independent Transmission System Operator (MISO), and in Case No. 2010-00043 in which Big Rivers Electric Corporation requested authorization to transfer control of its transmission system to the MISO.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been engaged by KIUC to estimate the difference in BREC's net margins over the period 2011 to 2013 between selling energy to the Smelters compared to selling to the wholesale market in the case in which the Smelters were no longer customers.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Section III presents a summary of my analysis and conclusions reached. Section IV provides a detailed description of the study and its results. Section V recaps my conclusions.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. The exhibits that I am sponsoring are listed in the table.

Exhibit No.	Description
MJM-1	Resume of Mathew Morey
MJM-2	Operating Parameters of BREC Generating Units
MJM-3	Summary of Net Margin Contribution Analysis

Q. WAS THIS TESTIMONY AND WERE THE EXHIBITS PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

III. SUMMARY

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. I conducted an assessment of the net margin contribution of the Smelters over the period 2011 through 2013 compared to the net margin contribution that could be achieved through sales by BREC to the Midwest ISO wholesale market in case the Smelters were no longer customers during that period of time. My analysis is summarized in Exhibit

MJM-3 attached hereto. The conclusion of this analysis is that the sale of energy to the Smelters over the three-year period will contribute an average net margin of approximately $83 million per year more than can be obtained from BREC's sales of that energy to the wholesale energy market.

Q. WHAT REASONS DO YOU GIVE FOR THE SIGNIFICANT DIFFERENCE IN THE SMELTERS' NET MARGIN CONTRIBUTION RELATIVE TO THE NET MARGINS THAT COULD BE ACHIEVED BY BREC THROUGH OFF-SYSTEM SALES IN THE ABSENCE OF THE SMELTERS' LOAD?

A. There are two reasons for the significant difference. First, sales to the Smelters occurs at a relatively fixed per MWh price that, over the next three years, is expected to be above the market price that BREC would obtain in connection with off-system sales. In fact, I am informed by counsel that, under their respective contracts, the Smelters together have an annual take-or-pay purchase obligation equal to 850 MW at a 98% load factor. This translates to roughly 7.3 million MWh per year as a take-or-pay purchase obligation. The take-or-pay obligation requires each Smelter to pay all demand related costs spread over the energy associated with the 98% load factor. Such demand related costs recovered by BREC through Smelter revenues includes all typical demand-related costs and a large body of costs that are typically considered energy related. To the extent that actual Smelter MWh purchases vary from the 98% take-or-pay target, the only cost variances (positive or negative) are those for the Fuel Adjustment Clause, the Environmental Surcharge, and the Non-FAC Purchased Power Adjustment. While there is some variation in the Smelter load from the take-or-pay target, the actual load factor is very close to that target.

Notwithstanding this Smelters' take-or-pay purchase obligation, I based my analysis of the difference in Smelters' net margin contribution and that of off-system sales on a simulation of BREC's generation dispatch with and without Smelter load so I could obtain an estimate of BREC's running costs, from which I could then determine the respective net margin contributions.

Q. WHAT IS THE SECOND REASON?

The second reason is that my simulation of the BREC generation dispatch against hourly market prices finds that BREC would only manage to sell an average of about 4,200 GWh per year in the wholesale market. BREC would not be able to sell 7,300 GWh of Smelter energy to the wholesale market because BREC generation units are frequently "out of the market."

Q. WERE YOU ABLE TO MODEL ALL OF THE FACTORS THAT MIGHT EFFECT BREC'S ABILITY TO SELL THE SMELTER LOAD TO THE WHOLESALE MARKET?

A. No. There are several factors that my analysis does not take into consideration that I believe makes it conservative in terms of the magnitude of the difference between net margins for the two cases examined. These factors make the analysis conservative in the sense that they would further limit the volume of off-system sales that BREC could make.

Q. WHAT FACTORS MAKE THE ANALYSIS CONSERVATIVE?

A. I did not factor in the existence of transmission constraints that would limit flows out of the BREC zone to Midwest ISO, absent the Smelters' load. Also, I did not factor in the reduction on the wholesale market clearing price of the simultaneous decrease in demand (i.e., loss of Smelter load) and increase in supply (i.e., resale of Smelter load) to the wholesale market. Third, in the absence of Smelter load, there could well be subsequent increases in operating costs due to increased cycling of some of BREC's generation units, which may also increase maintenance costs, and forced outage rates. I did not factor in this likely production cost increase.

Q. WHAT DOES YOUR ANALYSIS DEMONSTRATE ABOUT THE VALUE OF THE SMELTERS' LOAD TO THE BREC SYSTEM?

A. In summary, the Smelter load plays a significant role in BREC's financial well being and serves an important economic role in the BREC service territory. The analysis I conducted demonstrates how important the Smelter load is to BREC and how much the sale of energy to the Smelters is to be preferred to a merchant generator situation in which BREC would seek to make full recovery of its revenue requirements through significant off-system sales to the wholesale energy market.

IV. ANALYSIS OF BREC ENERGY SALES REVENUES AND OPERATING COSTS.

Q. PLEASE DEFINE THE MARKET PREMISE THAT UNDERLIES YOUR ANALYSIS AND FINDINGS?

A. The retail market profile of BREC is dominated by sales to two aluminum smelters, Alcan and Century Aluminum. The process of aluminum smelting takes place in long production lines of numerous carbon-lined steel containers referred to as reduction pots and involves very intensive use of electricity in order to form molten aluminum from alumina. The smelting process is continuous, so that the electricity usage pattern of aluminum smelters over time is unusually constant. This is reflected in unusually high load factors; each of the Smelters served by Big Rivers has an annual load factor close to unity.

Q. WHAT WAS THE SMELTER CONTRIBUTION TO BREC RETAIL REVENUES IN 2010?

A. During 2010, the Smelters had a combined average demand of approximately 820 MW that corresponded to 7,165,400 MWh of energy sales, a load factor of very nearly 100%. Again, I need to point out that this is the actual sales, and that the Smelters' take-or-pay obligation requires them to pay for nearly 7,300 GWh of energy at the contract rate.

Actual BREC sales to the Smelters during 2010 constituted 71.4% of total retail sales. The Smelter's load provided a very significant proportion of BREC's 2010 retail revenue (approximately 56%), and would be expected to continue to contribute a significant proportion of BREC's retail revenue over the foreseeable future.

Q. WOULD YOU EXPECT BREC TO BE ABLE TO MAKE SALES TO THE WHOLESALE MARKET THAT COULD CONTRIBUTE 56% OR MORE OF BREC'S RETAIL REVENUE GOING FORWARD?

A. No. Absent sales to the Smelters, BREC would need to seek alternative revenues through a similar level of sales within regional wholesale markets, recognizing that energy generation and thus production costs may also change. Thus, the overarching issue I addressed in my analysis revolves around the question of whether BREC as a merchant generator could achieve an equivalent level of margin contribution from off-system sales in the wholesale energy market as it receives from the Smelters.

Q. HOW WOULD BREC SELL LARGE QUANTITIES OF POWER, UPWARDS OF 800 MW, WITHIN REGIONAL WHOLESALE MARKETS?

A. BREC'S transmission network is interconnected to the system of the wholesale market of the upper midwest organized under the auspices of the Midwest Independent Transmission System Operator (Midwest ISO). BREC was fully integrated into Midwest ISO late last year in order to satisfy its reserve requirements. Thus BREC's network, including several generation nodes, is now an integral part of the Midwest ISO wholesale market footprint. As a full member of MISO, BREC must adhere to the various regulations and market rules of Midwest ISO, which are codified within Midwest ISO's Open Access Transmission Tariff, market rules, and various regulations regarding operational and planning governance. While BREC's membership in Midwest ISO is costly, through Midwest ISO, BREC has available an established structure of market protocols covering scheduling, supply auctions, and settlements. BREC can thus engage in pre-scheduled short- and long-term sales to potential buyers both within and outside the Midwest ISO footprint. In addition, BREC can participate in Midwest ISO day-ahead and real-time energy and reserve markets.

Q. IN YOUR OPINION, DOES MIDWEST ISO MEMBERSHIP IMPLY, FROM A FINANCIAL PERSPECTIVE, THAT BREC SHOULD BE INDIFFERENT BETWEEN SALES TO THE SMELTERS AND OFF-SYSTEM SALES THROUGH THE MIDWEST ISO WHOLESALE MARKETS?

A. No. While BREC's membership in Midwest ISO facilitates participation in wholesale markets, it does not fully address the potential shortfall in revenue that could occur if BREC attempted to sell annually more than 7 million MWh to the wholesale market rather than to the Smelters over the next several years. In this respect, my analysis sought answers to two questions in the context of a hypothetical scenario in which BREC no longer served Smelter loads and turned instead to the Midwest ISO energy markets to replace that revenue: 1) Will BREC be able to engage in near-term (i.e., day-ahead and real-time) and longer-term forward sales in the Midwest ISO market and achieve revenue flows sufficient to cover production costs? and 2) Would BREC's off-system sales in Midwest ISO energy markets obtain sufficient margins above production costs to replace the margin contribution associated with current and future (expected) sales to the Smelters?

Q. PLEASE EXPLAIN WHAT YOU DID TO OBTAIN ANSWERS TO THOSE TWO QUESTIONS.

A. The analysis I performed focuses on a comparison of the net margin associated with sales to the Smelters and the net margin associated with the alternative of BREC making sales to the wholesale market over the period 2011 to 2013. I limited my analysis to 2011-2013 because this is how far out reliable wholesale market information is publicly available. Also, as I explain later, this time period was sufficiently long for a study of this type. I make use of BREC's forecast of Smelter rates ($/MWh) over the 2011-2013 period. It is my understanding that KIUC is challenging the rate increase sought by BREC, which could ultimately effect those rates, but since I cannot predict the outcome of this rate case I simply used BREC's rate forecast.

Q. WHAT DO YOU MEAN BY NET MARGIN?

A. Net margin is the difference between revenues and production costs. Given energy purchases by the Smelters from BREC, the resulting revenue flow is determined by the price levels defined by the underlying power contracts, while production costs are determined by the operating costs of BREC's generating units dispatched to serve the Smelter load and all other retail load BREC serves.

Q. WHAT DETERMINES BREC'S GENERATION OPERATING COSTS?

A. Operating costs are a function of fuel costs and generator unit operating parameters such as unit heat rates, unit ramp rates, commitment constraints (e.g., minimum start up time and costs), maximum and minimum levels of output (MW), and maintenance schedules and forced outages. Operating costs are also a function of operational constraints related to maintaining reliability and voltage support. Operating costs are ultimately determined by BREC's production dispatch of its generation units to serve load, which takes account of input fuel costs and the various operating parameters and constraints.

Q. WHAT OTHER FACTORS WOULD DETERMINE WHETHER BREC COULD MAKE SUFFICIENT NET MARGINS FROM SALES TO WHOLESALE MARKET ABSENT SALES TO THE SMELTERS?

A. There are at least three factors that would play roles in determining whether BREC could earn net margins from off-system sales equivalent to what it earns through sales to the Smelters. The first factor is the wholesale market price that BREC could obtain for sales into the Midwest ISO market. If BREC were not making over 7 million MWh sales annually to the Smelters, it would free up a significant proportion of BREC's generating capacity, over 820 MW, to make potential sales within Midwest ISO markets. The average load across the retail markets served by BREC without the Smelter load averages about 418 MW. It is possible that the net margin on sales within Midwest ISO wholesale markets could be greater or less than the net margin on sales to the Smelters.

An examination of wholesale prices (i.e., Locational Marginal Prices (LMPs) expressed in $/MWh) at the network locations of BREC generators indicates that they vary and at times may be less than and at other times greater than the effective rates ($/MWh) the Smelters pay to BREC. There are occasional timeframes when the LMPs are significantly above the effective rates for the Smelters. However, these hours are comparatively few. In contrast, for a significant number of hours, LMPs at the BREC network locations are lower than the effective rates the Smelters pay to BREC, and for some hours LMPs fall below the running costs of BREC's generator units.

Q. WHAT IS THE SECOND FACTOR?

A. The available capacity (MW) for sale may be higher if BREC is not serving the Smelter load. It would appear from BREC's historical dispatch record that, when BREC's generators are dispatched to serve Smelter loads, they may be partially constrained and subject to redispatch during some hours to maintain reliability. If the same generation units are dispatched to make sales to the wholesale energy market, these constraints may not be present, and therefore additional capacity, albeit not a significant amount, may be available for sales to the market.

Q. WHAT IS THE THIRD FACTOR?

A. The third factor has to do with transmission line constraints. Sales to the Midwest ISO wholesale energy market rather than to the Smelters may entail substantial increases in line flows on local transmission facilities, creating the potential for substantial flow constraints on some lines that could decrease the quantities sold to the market. I did not account for possible transmission constraints in the production cost simulations, as recognition of flow limits would require the application of a larger scale transmission load flow/dispatch model (i.e., a security constrained optimal power flow (SC-OPF) model) to understand, with reasonable accuracy, the conditions and timeframes over which local networks are flow limited, as well as the depth of the constraints.

Q. WHAT EFFECT DOES IGNORING TRANSMISISON LINE CONSTRAINTS HAVE ON THE OUTCOMES OF YOUR ANALYSIS?

A. Not incorporating transmission constraints means that the immediate study probably overstates the quantity of MWh off-system sales BREC can make to the Midwest ISO market and likely overstates the net margin contribution that BREC could expect to obtain through wholesale sales.

Q. PLEASE DESCRIBE THE DISPATCH SIMULATION STUDY METHODOLOGY, DATA INPUTS AND ASSUMPTIONS, AND ANALYTICAL TOOLS USED TO PERFORM THE STUDY?

A. The simulation study I conducted is a comparative analysis, conducted for the years 2011, 2012, and 2013. There are two cases considered in this study. The case in which BREC makes sales to the Smelters is referred to as the Status Quo Case. For each year in the study period, I estimate the net margin realized under continued sales to the Smelters. The change case, in which I assume BREC makes sales to the wholesale market rather than to the Smelters I refer to as the Wholesale Market Case. I similarly compute the net margin realized by BREC for sales to the wholesale market. The results of these two cases are then compared.

Q. PLEASE PROVIDE ADDITIONAL DETAILS ABOUT THE COMPARATIVE STUDY YOU PERFORMED?

A. The comparative analysis estimates the MW of BREC generation unit capacity that would be economically dispatched each hour throughout a year (i.e., 8,760 hours) under the Status Quo Case and again under the Wholesale Market Case. The economic dispatch analysis largely relies upon data and information provided by BREC including observed historical loads for the Smelters and the remaining retail markets BREC serves, generator unit operating characteristics and parameters, the actual hourly dispatch over the period defined by BREC as the test year, variable Operations and Maintenance (O&M) expenses, and projections of primary fuel costs. The various operating characteristics and parameters of BREC generator units are presented in Exhibit MJM-3.

Q. WHAT IS THE BASIS OF THE HOURLY MARKET PRICES USED TO DETERMINE THE REVENUE BREC WOULD OBTAIN THROUGH SALES TO THE MIDWEST ISO WHOLESALE ENERGY MARKET?

A. The study estimates the hourly wholesale market prices that BREC would receive for sales into the Midwest ISO energy market for the years 2011 through 2013. I based the estimate of the BREC locational prices for these years on the historical relationship between the hourly prices at the BREC-Midwest ISO interface for the test year and prices for PJM West for the corresponding period of time and the forward financial contracts for PJM West, which is a major commercial hub for which financial contracts are traded through the NYMEX/CME. I could have extended the analysis to 2014, but did not because the purpose of the exercise was to demonstrate the significance of the Smelter contribution to net margins and three years was quite sufficient to accomplish that. In addition, a glance at the financial model provided by BREC to KIUC 1-43 indicates that the market price would continue to fall below the Smelter rate and that the shortfall in revenue would continue in 2014. One of the reasons for the simulation was to obtain a reasonable estimate of the volume of energy that BREC could sell annually in the wholesale market, so it was not necessary to extend the analysis to 2014 to accomplish that objective.

I used forward monthly financial contracts for PJM West to develop projections of hourly PJM West prices for 2011, 2012, and 2013. The hourly historical PJM prices are averaged and then compared to the PJM West forward 5 x 16 contracts. The observed hourly prices of PJM West, covering all hours, are then adjusted for each month according to the price change implied by the PJM West forward contracts. I then adjusted the BREC-Midwest ISO interface prices to account for the locational basis point difference between the interface price and the PJM West price. Basis point price differences between PJM West prices and the BREC-Midwest ISO interface prices are estimated monthly and represented as multiplicative factors (i.e., ratios). Given projections of hourly prices for PJM West, obtained from PJM West futures, BREC interface prices were estimated by applying the monthly historical factors for basis point differences.

Q. ONCE YOU HAVE THE HOURLY PRICES ESTIMATED FOR THE STUDY PERIOD, WHAT REMAINS TO BE DONE TO DETERMNE THE NET

MARGINS UNDER THE STATUS QUO CASE AND THE WHOLESALE MARKET CASE?

A. The final step to determine the net margins in the two cases is to compare a simulation of BREC's economic dispatch of its generation units in the Status Quo Case with a simulation of BREC's economic dispatch in the Wholesale Market Case. I assumed that BREC self schedules its generation to serve its retail markets and sells any remaining available (i.e., excess) capacity in the Midwest ISO wholesale market, subject to the constraint that market prices at the relevant generator locations are greater than the running costs of units not yet committed to serving native loads. The two simulations are conducted for the years 2011 through 2013. The main results including revenues, production costs, and net margins are then summarized by month and compared.

Q. WHAT ARE THE RESULTS OF THE SIMULATIONS IN TERMS OF BREC'S ABILITY TO OBTAIN NET MARGINS FROM SALES TO THE WHOLESALE MARKET EQUIVALENT TO THOSE OBTAINED THROUGH SALES TO THE SMELTERS?

A. The results of the study in terms of net margins under the two cases are presented in Exhibit MJM-3. The net margin contribution from the Smelters averages $162 million per year over the study period, and is based on an assumption that BREC sells an average of 7.3 million MWh to them in each year 2011 through 2013 and that the prices the Smelters pay for that energy are those provided by BREC in its response to KIUC 1-43, at worksheet entitled Charts, row 144 for the years 2011, 2012 and 2013. The Status Quo Case hourly generation dispatch, which is based on BREC's actual historical dispatch in 2010, as I discussed above, was held constant over the study period.

The results of the Wholesale Market Case indicate that BREC would sell an average of 4.2 million MWh to the Midwest ISO wholesale market at an average price of just over $40 per MWh. The net margin over the three years from market-based sales is estimated to average roughly $79 million per year. The difference in the net margin contributed by sales to the Smelters and the net margin contributed by alternatively selling to the market averages $83 million per year. Thus, sales to the Smelters are expected to contribute over $83 million per year more to BREC's net margins than would sales to the wholesale market in the absence of Smelter load.

As shown in Exhibit MJM-3, the Smelters are forecast to make rising margin contributions, though sales levels are assumed to remain comparatively constant over the 2011 to 2013 period.

Q. ARE THE RESULTS OF YOUR ANALYSIS CONFIRMED BY ANY OTHER COMPARISION THAT CAN BE MADE OF THE STATUS QUO CASE AND THE WHOLESALE MARKET CASE?

A. Yes. The results of my analysis of the Status Quo Case and the Wholesale Market Case are consistent with BREC's own financial model spreadsheet that was provided to me in response to data request KIUC 1-43. In that spreadsheet, [KIUC 1-43 – Multi-Yr Financial Forecast Model.xls], in the tab labeled "Charts", the Effective Rate for the Smelters is provided in row 159 for 2011 through 2014. BREC's estimate of the forward market price is provided in row 160. The market prices that I have used in my analysis are similar to BREC's predicted market prices in its financial model. Given BREC's numbers, the general result that would be produced by comparing the Smelter rates and the predicted market prices will be a forecast of revenue shortfall if the Smelter load must be sold to the Midwest ISO market. The financial implications are consistent with the results of my own analysis.

Q. GIVEN YOUR ANALYSIS OF THE NET MARGIN CONTRIBUTION MADE BY BREC'S SALES TO THE WHOLESALE MARKET, WHAT WOULD THE AVERAGE MARKET PRICE HAVE TO BE OVER THE THREE-YEAR STUDY PERIOD FOR BREC TO ROUGHLY ACHIEVE THE SAME LEVEL OF REVENUE THROUGH OFF-SYSTEM SALES AS IT WOULD EXPECT TO OBTAIN THROUGH SALES TO THE SMELTERS?

A. If I assume that BREC's MWh sales to the wholesale market were the same as I had determined in the simulation study for each of the three years 2011 to 2013, which average about 4,200 GWh, the average market price over the three years would have to just about double from its expected level for BREC to achieve an equivalent net margin contribution equal to that made by sales to the Smelters.

Even if I assume that BREC could achieve a level of off-system sales equal to the 7,300 GWh sold annually to the Smelters, which as I have explained does not appear likely to me, the market price over the three years would have to increase by an average of about 26% for BREC to achieve from market sales the net margin contribution it receives from the Smelters.

Q. WOULD YOU EXPECT THAT THESE MARKET PRICE LEVELS COULD BE REALIZED OVER THE NEXT THREE YEARS FOR BREC TO ACHIEVE A COMPARABLE NET MARGIN CONTRIBUTION FROM OFF-SYSTEM SALES?

A. No. With the overall economy in a very slow recovery, and with the long-term impact of permanent load reductions regionally as well as the increasing incidence of wind resources displacing baseload and peaking capacity in Midwest ISO, I do not see how these market price levels could be achieved over these next three years.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS OF THE COMPARISION OF THE STATUS QUO CASE AND THE WHOLESALE MARKET CASE?

A. In brief, in the absence of sales to the Smelters at the anticipated prices described above, BREC could be expected to make up a non-trivial share of the margin contribution to financial costs, notwithstanding the possibility of substantial transmission line flow constraints. However, the contribution to net margin from wholesale market sales would, most likely, be approximately half the level of contribution to net margin obtained from continued sales to the Smelters. Specifically, the contribution to BREC's net margins under the Wholesale Market Case would likely decline by an average of 22%, when compared to the corresponding annual net margins under the Status Quo Case, which assumes continued service to the Smelters. These results represent significant economic losses in the form of foregone net margin equal to about $83 million per year.

V. CONCLUSION.

Q. WHAT CONCLUSIONS DO YOU REACH ABOUT THE VALUE OF THE SMELTER LOAD TO BREC'S REVENUE RECOVERY COMPARED TO RECOVERY THROUGH SALES TO THE WHOLESALE MARKET?

A. On the basis of my analysis of the Status Quo Case compared to the Wholesale Market Case, it is clear that continued sales to the Smelters are likely to be the beneficial approach compared to attempting to sell those same MWh in the wholesale market. From my analysis, BREC will be unable to make sufficient sales to the market to match the net margin contribution that the Smelters make annually.

Q. DOES THIS CONCLUDE YOUR TESTMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	**)**	
Corporation for a General Adjustment	**)**	
In Rates	**)**	**Case No. 2011-00036**

EXHIBIT MJM-1

OF

DR. MATHEW J. MOREY

MATHEW J. MOREY

RESUME

March 2011

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M.S., University of Illinois-Urbana/Champaign, 1975, Economics.
B.S., University of Illinois-Urbana/Champaign, 1973, Economics.

POSITIONS HELD:

Senior Consultant, Christensen Associates Energy Consulting, July 2003 – Date
Principal, Envision Consulting, October 2000 – June 2003
Director, Economics, Edison Electric Institute, February 1996 – October 2000
President, Center for Regulatory Studies, Illinois State University, 1991 – 1996
Vice President, Center for Regulatory Studies, 1985 – 1991
Director of Energy Forecasting, Central Illinois Light Company, 1991 – 1992
Special Term Appointment, Argonne National Laboratory, 1987 – 1992
Associate Professor of Economics, Illinois State University, 1983 – 1996
Assistant Professor of Economics, Indiana University, 1978 – 1983
Assistant Professor of Economics, Arizona State University, 1977 – 1978

SELECTED PROFESSIONAL ACTIVITIES:

Research Advisory Committee, National Regulatory Research Institute, 1995-1996

PROFESSIONAL EXPERIENCE:

I am a Senior Consultant at Christensen Associates. I have broad experience in the electric industry working on issues connected to all aspects of industry restructuring, wholesale and retail market design, system operations, and retail and wholesale rates and tariffs. I have worked on projects involving transmission congestion management and pricing systems, market power and market monitoring, market design and incentive regulation, among others. Prior to joining Christensen Associates, I was Principal of Envision Consulting, which I founded in 2000. I served as Chief Economist with the Edison Electric Institute from 1996 to 2000. I guided the development of EEI's positions on economic and regulatory policy pertaining to the restructuring of the industry's wholesale and retail markets. I shaped EEI's economic framework for efficient pricing and practices within competitive and regulated markets, transmission and distribution pricing and rate design, including congestion pricing practices, merger and market power policies at the federal and state level, and energy business development. I have testified before state and federal regulatory agencies and state legislative bodies on a wide range of industry issues including impacts of utility mergers, stranded costs, market power measurement and mitigation, affiliate codes of conduct, modeling fuel costs in fuel adjustment cases, costs and benefits of Regional Transmission Organizations, utility-affiliate transfer pricing rules, cost of service studies in retail rate cases and regulatory policy regarding the design of distribution and transmission rates.

MAJOR PROJECTS:

Assisted a national trade group with understanding the costs and benefits associated with nationwide expansion of the extra high-voltage transmission system.

Assisted the Commonwealth of Puerto Rico with the development of an open access transmission system, including development of an open access transmission tariff, operating agreements, generator interconnection procedures and agreements, setting transmission access charges and rates for the full set of ancillary services.

Assisted industrial customers with assessment of utility requests to increase base rates and assessments of requests to adjust fuel cost recovery tariffs.

Assisted a national trade association with the analysis of RTO and regional LMP-based market performance.

Assisted a coalition of market participants in the PJM RTO markets about the implications of the implementation of the PJM Reliability Pricing Model, intended to ensure resource adequacy.

Assisted an investor-owned electric utility with evaluation of feasible options to membership in a Regional Transmission Organization.

Assisted an independent transmission company with the evaluation of the costs and benefits of transmission expansion options.

Conducted a review of federal and state experience with utility codes of conduct and affiliate transaction pricing rules in the U.S. for a Canadian utility.

Conducted a review of how stranded cost issues were addressed in the U.S. at the State and Federal levels for a Canadian utility.

At the request of a state regulatory agency, performed a critique of a cost-benefit study of a utility's membership in the PJM RTO and prepared direct testimony about the critique.

Assisted the National Rural Electric Cooperative Association with comments to the Federal Energy Regulatory Commission on the analysis of market power as it relates to the granting of market-based rate authority.

Performed critiques for the National Rural Electric Cooperative Association of various studies of the costs and benefits of restructuring of the wholesale and retail power markets.

Performed analysis for LGE Energy Corporation of the costs and benefits of alternative regional transmission organizational arrangements and assisted the company in its process of exiting from the Midwest Independent Transmission System Operator.

Assisted Detroit Edison Company and DTE Energy Trading, Inc. with issues related to transmission pricing that arise from the elimination of through and out rates and the application of the Seams Elimination Cost Adjustment (SECA) charges.

Conducted a review for a large Canadian energy firm of the proposed congestion management principles for operation of the Alberta transmission system and improvements in the design of the Alberta wholesale energy market, and prepared testimony on the basis of that analysis.

Assisted an independent transmission company with development of comments on the FERC Standard Market Design Notice of Proposed Rulemaking and advised on transmission pricing and performance-based regulation for transmission companies.

Performed a study for the Independent System Operator of New England on transmission congestion management and market power issues as they pertain to implementation of a Standard Market Design.

Consultant to a national trade association on electric industry restructuring issues including market design and market power, transmission congestion management, transmission regulation, RTO design and impacts of federal energy legislation.

Assisted a utility with assessing options for satisfying FERC Order Nos. 888 and 2000 while continuing to provide reliable service to its native load customers at a reasonable cost.

Assisted a New York investment firm in assessing risks associated with power supply contracts.

PUBLICATIONS:

"Managing Transmission Risk in Wholesale Power Markets," with Laurence D. Kirsch, *The Electricity Journal*, Volume 22, Issue 9, October 2009, pp. 26-37.

"Electricity Price Impacts of Alternative Greenhouse Gas Emission Cap-and-Trade Programs," with Bruce Edelston, Dave Armstrong, and Laurence Kirsch, *The Electricity Journal*, Volume 22, Issue 6, July 2009, pp. 37-46.

"Efficient Allocation of Reserve Costs in RTO Markets," with Laurence D. Kirsch, *The Electricity Journal*, Volume 19, Issue 8, October 2006, pp. 43-51.

"RTOs and Electricity Restructuring: the Chasm Between Promise and Practice," with B. Kelly Eakin and Laurence D. Kirsch, *The Electricity Journal*, Volume 18, Number 1, January/February 2005, pp. 1-21.

"How Can FERC Find Its Way Out of the SMD Cul-de-Sac? Stimulate the Transmission Sector!" with Christina C. Forbes, *The Electricity Journal*, Volume 16, Number 7, August/September 2003, pp. 74-85.

"Performance-based Regulation for Independent Transmission Companies: 'Delivering' the Promise of Standard Market Design," *The Electricity Journal*, Volume 16, Number 5, June 2003, pp. 35-51.

"The Role of the Independent Transmission Company in Wholesale Electricity Markets," with Eric Hirst, *The Electricity Journal*, Volume 16, Number 4, May 2003, pp. 31-45.

"ITP Building Blocks: Functions and Institutions," with Eric Hirst, *The Electricity Journal*, Volume 16, Number 3, April 2003, pp. 29-41.

"The Ties That Bind," with Julia Valliere, *Electric Perspectives*, March/April 2001, pp. 35-43.

"House of Cards," with Russell Tucker and Liz Stipnieks, *Electric Perspectives*, March/April, 1999, pp. 27-34.

"The Efficient Utility: Labor, Capital and Profit," letter to the editor of Public Utilities Fortnightly on an article by Taylor and Thompson in the September 1, 1995 issue of PUF, with L. Dean Hiebert, *Public Utilities Fortnightly,* January 1996.

"Sudden Oil Price Changes: The Effect on U.S. Gasoline Demand," with R.K. Goel, *Opec Review*, Autumn 1995, pp. 203-218.

"The Interdependence of Cigarettes and Liquor Demand," with R.K. Goel, *Southern Economic Journal*, September 1995, pp. 451-459.

"Trans-Atlantic Lessons in Electric Energy Market Development: Impressions from the U.S. and U.K.," *TB&A inforum,* Volume 1, Issue 4, May-June 1994 and Volume 2, Issue 2, September-October 1994.

"A Cross-Country Comparison of Consumer Discount Rates," with W. V. Weber and J. K. Highfill, *The Changing Environment of International Financial Markets: Issues and Analysis*, New York: Macmillan, 1993, pp. 56-68.

"The Impact of the 1973 Oil Embargo: A Nonparametric Analysis," with R.K. Goel, *Energy Economics*, January 1993, pp. 39-48.

"How Effective are Conservation Brochures," with J.L. Carlson, in *Public Utilities Fortnightly*, Volume 128, Number 4, August 15, 1991.

"The Economic Contribution of Women in the Household: Evidence from an African LDC," with R.D. Singh, in *Economic Development and Cultural Change*, 1987, pp. 743-765.

"MicroTSP: A Review," *The American Statistician*, Vol. 41, No. 2, May 1987, pp. 143-145.

"Bootstrapping the Durbin-Watson Statistic," with Sejong Wang, in the *Proceedings of the American Statistical Association, Business Statistics Section*, Fall 1985.

"Robustifying the Durbin-Watson Test for Serial Correlation," in the *Proceedings of the American Statistical Association, Business Statistics Section*, Fall 1985.

"Small Sample Behavior of Bootstrapped and Jackknifed Regression Estimates," with Leslie M. Schenk, in the *Proceedings of the American Statistical Association, Business Statistics Section*, Fall 1984.

"The Statistical Implications of Preliminary Specification Error Testing," *Journal of Econometrics*, 25, 1984.

"A Time Series Extension of a Specification Error Test Due to Ramsey," with David Spencer, in *Applied Time Series Analysis*, O.D. Anderson ed., North-Holland, 1982.

"The Statistical Implications of Spurious Response in Sample Surveys," with Robert Schmitz, in the *Proceedings of the American Statistical Association, Business Statistics Section*, Fall 1980.

"Pooled Cross-Section Time Series Education Evaluation: Source, Result and Correction of Serially Correlated Errors," with William Becker, *American Economic Review*, May 1980.

"Autocorrelation Pre-Test Estimators," Chapter 7 in *The Statistical Consequences of Pre-Test and Stein Rule Estimators in Economics*, with G.G. Judge and M.E. Bock, North-Holland, 1978.

PROFESSIONAL PAPERS:

"Analysis of Benefits and Costs of RTO Membership Options," prepared for a utility in the Midwest, March 2011.

"Fundamentals of Power System Reliability," with Robert Camfield and Laurence Kirsch, prepared for American Coalition for Clean Coal Electricity, December 2010.

"Analysis of SPP Membership Benefits and Costs," prepared for a utility in the Midwest, December 2010.

"Taylorville Energy Center Project: Economic Impacts On Illinois Retail Electricity Rates and Economy," with Laurence Kirsch and Michael Welsh, for The STOP Coalition, April 16, 2010.

"Assessment of National EHV Transmission Grid Overlay Proposals: Cost-Benefit Methodologies and Claims," with Bruce Edleston, Robert Camfield, and Chris De Marco, for the Large Public Power Council, February 22, 2010.

"Overcoming Barriers to Efficient Investment in Generation: Regulatory vs. Competitive Based Approaches," with Laurence D. Kirsch, prepared for the National Rural Electric Cooperative Association, September 2009.

"Analysis of the Electricity Price Impacts of Alternative Carbon Emission Cap-And-Trade Programs In the Midwest," with Bruce L. Edelston, Laurence D. Kirsch, and David Armstrong, prepared for Indiana Municipal Power Agency, Madison Gas and Electric Company, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy, March 31, 2009.

"The Regional Transmission Organization Report Card: Wholesale Electricity Markets and RTO Performance Evaluation," 3rd Edition, prepared for the National Rural Electric Cooperative Association, with Laurence D. Kirsch, Brad Wagner, Bruce Chapman, February, 2009.

"Managing Transmission Risk Through Forecasts of Transmission Loading Relief Calls," with Laurence Kirsch, Brad Wagner, and Dave Armstrong, Electric Power Research Institute, EPRI Report ID #1015871, November, 2008.

"The Compete Coalition Oversells Independent Study Findings," with Laurence D. Kirsch, prepared for the American Public Power Association and the National Rural Electric Cooperative Association, December, 2007.

"Forecasting Transmission Loading Relief Calls With Publicly Available Information," with Laurence Kirsch, Brad Wagner, and Dan Hansen, Electric Power Research Institute, EPRI Report ID # 1013775, November, 2007.

"The Regional Transmission Organization Report Card: Wholesale Electricity Markets and RTO Performance Evaluation," 2nd Edition, prepared for National Rural Electric Cooperative Association, with Laurence D. Kirsch, Brad Wagner, Bruce Chapman, Emilie McHugh, August, 2007.

"Analysis of Issues in Estimating a Comparable Regional Average Firm Full Requirements Service Price," prepared for the Connecticut Department of Public Utility Control, with Robert J. Camfield, Daniel G. Hansen, and Laurence D. Kirsch, June, 2007.

"The Regional Transmission Organization Report Card: Wholesale Electricity Markets and RTO Performance Evaluation," prepared for National Rural Electric Cooperative Association, with Laurence D. Kirsch, Brad Wagner, Bruce Chapman, Emilie McHugh, October, 2006.

"Efficient Allocation of Reserve Costs in RTO Markets," with L.D. Kirsch, working paper, August, 2006.

"Hedging Long-term Transmission Price Risks Associated With Generation Investments," with Laurence D. Kirsch, prepared for the Electric Power Research Institute, December, 2005.

"Beyond Belief: A Critique of the Cambridge Energy Research Associates' Special Report," with Laurence D. Kirsch, prepared for the National Rural Electric Cooperative Association, November 17, 2005.

"Transmission Price Risk Management," with L.D. Kirsch, Electric Power Research Institute, Product ID# 1012475, October, 2005.

"Global Energy Decision's 'Putting Competitive Power Markets to the Test': An Alternative View of the Evidence," with Laurence D. Kirsch, prepared for the National Rural Electric Cooperative Association, August 2005.

"Critique of the Charles River Associates Study 'The Benefits And Costs In North Carolina Of Dominion North Carolina Power Joining PJM'," with Laurence D. Kirsch, prepared for the Public Staff of the North Carolina Utilities Commission, September 30, 2004.

"Supplemental Investigation Into the Costs and Benefits to Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.," with Laurence D. Kirsch, prepared for LGE Energy Corporation, September 29, 2004.

"Preliminary Blueprint for Addressing Generation Market Power Issues," with B. Kelly Eakin, prepared for the National Rural Electric Cooperative Association, February 1, 2004.

"Erecting Sandcastles from Numbers: The CAEM Study of Restructuring Electricity Markets," with Laurence D. Kirsch, Steven Brathwait, and Kelly Eakin, December 3, 2003, prepared for National Rural Electric Cooperative Association.

"A Cost-Benefit Analysis of RTO Options for LGE Energy Corporation," prepared for LGE Energy Corporation, with Laurence D. Kirsch, Robert J. Camfield, Blagoy Borissov, September 22, 2003.

"Performance-based Regulation for Independent Transmission Companies," prepared for TRANSLink Transmission Company, LLC, January 2003.

"Economic Regulation and Transmission," prepared for TRANSLink Transmission Company, LLC, January 2003.

"Congestion Management System (CMS) Implementation Studies Related to Congestion," with F. L. Alvarado, B. Borrisov, R. C. Hemphill, L. D. Kirsch, R. Rajamaran, Laurits R. Christensen Associates, Inc., prepared for the Independent System Operator of New England, January 14, 2003.

"Transmission Business Models: The Role of Independent Transmission Companies in Competitive Wholesale Electricity Market," with Eric Hirst, submitted as a comment in FERC Docket RM01-12-000, November 2002.

"Regional Transmission Organizations: Who Does What to Whom," with Eric Hirst, July 2002.

"Ensuring Sufficient Generation Capacity During the Transition to Competitive Electricity Markets," prepared for Edison Electric Institute, appended to EEI Comments in FERC Docket No. EX01-1-000, Ensuring Sufficient Capacity Reserves in Today's Energy Markets, November 2001.

"Power Market Auction Design: Rules and Lessons in Market-based Control for the New Electricity Industry," prepared for Edison Electric Institute, September 2001.

"The Truth About the HVAC Industry: Why Utility Participation is Good for Consumers," with Russell Tucker and Liz Stipnieks, 1999.

"Putting Demand Back In Demand-Side Management," paper prepared for presentation to the Mid-America Regulatory Conference, Session on Electric DSM/IRP: Fact or Fiction in the Brave New World of Electricity Competition, Milwaukee, WI, June 21, 1994, 8 pp.

"636 To The Burnertip: Effects of Pipeline Industry Restructuring on LDCs and How State Regulators are Responding," with Duane Abbott, paper prepared for presentation at gas industry conferences sponsored by the Institute for Gas Technology, fall 1994, 40 pp.

"Preliminary Estimates of Price Sensitivity for Customers on NMPC's SC-3 and SC-3A Tariffs," with Carl Peterson, prepared under contract with Niagara Mohawk Power Corporation, February 1994, 75 pp.

PRESENTATIONS:

"Managing Transmission Curtailment Risk," with L. Kirsch, B. Wagner, and D. Armstrong, Electric Power Research Institute, Advisory Group Meeting, September 8, 2008.

"Forecasting TLRs: An Application to a Problematic Flowgate," with L. Kirsch and B. Wagner, Electric Power Research Institute, Advisory Group Meeting, February 18, 2008.

"Electricity Market Performance and Reform Options: Participant Perspectives," Institute of Public Utilities, 39th Annual Regulatory Policy Conference, Charleston, S.C., December 5, 2007.

"Wholesale Electricity Market Risks," Utility Basics Course, Wisconsin Public Utilities Institute, University of Wisconsin, October 16, 2007.

"Forecasting TLRs With Publicly Available Information," with L. Kirsch, Electric Power Research Institute, Advisory Group Meeting, Washington, D.C., September 24, 2007.

"Wholesale Electricity Costing and Pricing," Camp NARUC, Institute of Public Utilities, Michigan State University, August 9, 2007.

"Managing Transmission Risk in Illiquid Markets," with L. D. Kirsch, Electric Power Research Institute, Advisory Group Meeting, Charlotte, North Carolina, August 24, 2006.

"Wholesale Electricity Costing and Pricing," Camp NARUC, Institute of Public Utilities, Michigan State University, August 10, 2006.

"Managing Transmission Price Risk," with Laurence Kirsch, Electric Power Research Institute, Interest Group Meeting, Washington, D.C., July 27, 2006.

"Installed Capacity Market Reforms: Assessing Risk for Generation," Electric Power Research Institute, Advisory Meetings, San Diego, California, February 6, 2006.

"The Costs and Benefits of Regional Transmission Organizations," Large Public Power Council Rates Committee Seminar, San Antonio, Texas, October 2, 2005.

"The Trials and Tribulations of a Fuel Cost Adjustment Mechanism," Large Public Power Council Rates Committee Seminar, San Antonio, Texas, October 2, 2005.

"Governance Structures for Transmission Networks: Addressing the Conflicts in Independence, Ownership and Functionality," EUCI Conference – Organization and Governance of the Market Agent, Washington, DC, March 30, 2005.

"Developing Transmission Through Performance-based Regulation," presented to the Center for Business Intelligence, Transmission Expansion: Investment, Incentives and Regional Approaches to Transmission Opportunities, Alexandria, VA, October 8, 2003.

"Incentive Regulation for Transmission," presented to the EEI Market Design Workshop, Madison, WI, July 29, 2003.

"Audit of OATi MECS 2002 Tag Data," presented to a Settlement Conference in FERC Docket No. EL02-111-000, May 6, 2003.

"Congestion Management," presented to the EEI Transmission Business School, Philadelphia, PA, March 19, 2002.

"Wholesale Electricity Market Design," presented to the EEI Transmission Business School, Philadelphia, PA., March 19, 2002.

"RTO Formation: Where Are We, What Have We Learned, Where Do We Go From Here?" presentation to EEI's *The RTO's Filings Conference*, Washington, D.C. November 2, 2000.

"Are Utilities Gaming the System," presentation to the EEI Strategic Issues Conference, Washington, D.C., October 1, 2000.

"Affiliate Transaction Pricing Rules or How To Swim Upstream With One Arm Tied Behind Your Back," presented to the EEI Property Accounting Committee Spring meeting, Dallas, TX, June 8, 2000.

"Distributed Generation: Is It the Wave of the Future?" presentation to the Spring Meeting of the National Association of State Utility Consumer Advocates, Portland, ME, June 5, 2000.

"An Analysis of Regional Wholesale Power Markets: Market Fundamentals," presentation made to staff at Constellation Power Source, Baltimore, MD, January 20, 2000.

"Codes of Conduct: Impacts on Utility Profitability," presented to the Chief Accounting Officers annual meeting, New Orleans, LA, September, 1999.

"A Market Economist's Perspective on Market Power in the Electric Industry," presented at the Electric Utility Business Environment Conference, Denver, CO, May 17, 1999.

"Transmission Market Design Principles," presented to the NARUC Subcommittee on Accounts, Winter Meeting, New Orleans, LA, March 22, 1999.

"Electric Industry Restructuring and Market Power," presented to the Joint Energy Council, Washington, D.C., February 28, 1999.

"Affiliate Transactions Pricing Issues," presented to EEI/AGA Corporate Accounting/Property Accounting Committee Meeting, New Orleans, LA, December 7, 1998.

"Market power principles and affiliate transaction pricing issues," presented to the NARUC Subcommittee on Accounts, Indianapolis, IN, October 13, 1998.

"Review of restructuring in the states," presented to the Financial Accounting Standards Board, Stanford, CN, June 23, 1998.

"Pricing Transmission and Congestion: The Role of Congestion Contracts," presented at Infocast conference, January 23, 1998.

PREPARED TESTIMONY, EXPERT TESTIMONY:

- Before the Federal Energy Regulatory Commission, on behalf of the National Rural Electric Cooperative Association, Affidavit of Dr. Laurence D. Kirsch and Dr. Mathew J. Morey on Behalf of the National Rural Electric Cooperative Association, PJM Power Providers Group v. PJM Interconnection LLC, and PJM Interconnection LLC, Docket Nos. EL11-20-000 and ER11-2875-000 (Not Consolidated), with Laurence Kirsch, March 4, 2011.
- Before the Maryland Public Service Commission, on behalf of Direct Energy Services LLC, In the Matter of the Merger of FirstEnergy Corp. and Allegheny Energy, Inc., Case No. 9233, October 4, 2010.
- Before the Pennsylvania Public Utility Commission, on behalf of Direct Energy Services LLC, In the matter of: Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code approving a change of control of West Penn Power Company And Trans-Allegheny Interstate Line Company, Docket Nos. A-2010-2176520 and A-2010-2176732, August 17, 2010.
- Before the Federal Energy Regulatory Commission, on behalf of the National Rural Electric Cooperative Association, "Affidavit of Dr. Mathew J. Morey," PJM Interconnection LLC, Docket Nos. A-2010-2176520 and A-2010-2176732, July 30, 2010.
- Before the Kentucky Public Service Commission, on behalf of the Kentucky Industrial Utility Customers, Inc., In the Matter of the Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of Its Transmission System to Midwest Independent Transmission System Operator, Inc., Case No. 2010-00043, May 2010.
- Before the Federal Energy Regulatory Commission, on behalf of the American Public Power Association and the National Rural Electric Cooperative Association, "Affidavit of Dr. Laurence D. Kirsch and Dr. Mathew J. Morey On Behalf of the American Public Power Association and the National Rural Electric Cooperative Association," Docket Nos. ER09-701-000 and ER09-701-001, May 19, 2009.
- Before the North Carolina Public Utilities Commission, on behalf of Nucor Steel-Hertford, In the Matter of Application of Dominion North Carolina Power for Authority to Adjust Its Electric Rates Pursuant to G.S. 62-133.2 and NCUC Rule R8-55, Docket No. E-22 Sub. 451, November 3, 2008.
- Before the Virginia State Corporation Commission, on behalf of Steel Dynamics, Inc. – Roanoke Bar Division, Case No. PUE-2008-00046, September 26, 2008, with R. Camfield.
- Before the Virginia State Corporation Commission, on behalf of Steel Dynamics, Inc. – Roanoke Bar Division, Case No. PUE-2008-00045, August 6, 2008.
- Before the North Carolina Public Utilities Commission, on behalf of Nucor Steel-Hertford, In the Matter of Application of Dominion North Carolina Power for Authority to Adjust Its Electric Rates Pursuant to G.S. 62-133.2 and NCUC Rule R8-55, Docket No. E-22 Sub. 444, October 26, 2007.
- Before the North Carolina Public Utilities Commission, on behalf of Nucor Steel-Hertford, In the Matter of Application of Dominion North Carolina Power for Authority to Adjust Its Electric Rates Pursuant to G.S. 62-133.2 and NCUC Rule R8-55, Docket No. E-22 Sub. 436, October 23, 2006.

- Before the Federal Energy Regulatory Commission, on behalf of the Detroit Edison Company and DTE Energy Trading, Inc., "Prepared Cross-Answering Testimony of Mathew J. Morey on Behalf of Detroit Edison Company and DTE Energy Trading, Inc.," in Docket No. EL02-111 *et al*, December 13, 2005.
- Before the Kentucky Public Service Commission, on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company, "Prepared Direct Testimony of Mathew J. Morey," in the matter of the application of Louisville Gas and Electric Company and Kentucky Utilities Company To Transfer Functional Control of Their Transmission System," Case No. 2003-00266.
- Before the Federal Energy Regulatory Commission, on behalf of the Detroit Edison Company and DTE Energy Trading, Inc., "Prepared Answering Testimony of Mathew J. Morey," in Docket No. EL02-111 *et al*, October 21, 2005.
- Before the Federal Energy Regulatory Commission, on behalf of the PJM Industrial Customer Coalition, "Affidavit of Mathew J. Morey and Laurence D. Kirsch," in Docket No. ER05-1410 and EL05-148, on the critique of the PJM Reliability Pricing Model proposal, October 19, 2005.
- Before the Federal Energy Regulatory Commission, on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company, "Testimony of Mathew J. Morey," in Docket No. EL05-99-000, on the matter of the formation of an independent coordinator of transmission as an alternative to membership in the Midwest Independent Transmission System Operator, October 7, 2005.
- Before the Federal Energy Regulatory Commission, on behalf of the National Rural Electric Cooperative Association, "Affidavit of Dr. Laurence D. Kirsch and Dr. Mathew J. Morey, in Docket No. EL03-236-000, on the subject of the PJM market monitor's three-pivotal supplier test for determining whether offer caps should be imposed in hours when the market is deemed not to be competitive.
- Before the Kentucky Public Service Commission, on behalf of LGE Energy Corporation, Additional Supplemental Rebuttal Testimony in the matter of "Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.," Case No. 2003-00266, filed April 1, 2005.
- Before the Federal Energy Regulatory Commission, on behalf of the National Rural Electric Cooperative Association, "Remarks of Mathew J. Morey On Behalf of the National Rural Electric Cooperative Association," Technical Conference on Generation Market Power and Affiliate Abuse, Docket No. RM04-7-000, January 27, 2005.
- Before the Federal Energy Regulatory Commission, on behalf of The Detroit Edison Company, in Docket No. ER05-6-000 et al, filed January 10, 2005, on problems with the use of OATI e-tag data in determining the SECA liability of Detroit Edison.
- Before the Kentucky Public Service Commission, on behalf of LGE Energy Corporation, Supplemental Rebuttal Testimony in the matter of "Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.," Case No. 2003-00266, filed January 10, 2005.
- Before the North Carolina Public Utilities Commission, on behalf of the Public Staff of the North Carolina Public Utilities Commission, in the matter of "Application of Dominion North Carolina Power for Authority to Transfer Functional Control of Transmission Assets to PJM, Interconnection, L.L.C.; Virginia Electric and Power Company, d/b/a/ Dominion North Carolina Power, Docket No. E22, SUB 418, filed September 30, 2004.

- Before the Kentucky Public Service Commission, on behalf of LGE Energy Corporation, in the matter of "Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.," Case No. 2003-00266, filed September 29, 2004.
- Before the Federal Energy Regulatory Commission, on behalf of the National Rural Electric Cooperative Association, "Remarks of Mathew J. Morey on Behalf of the National Rural Electric Cooperative Association," Technical Conference Initiation of Rulemaking Proceeding on Market-based Rates, June 9, 2004.
- Before the Kentucky Public Service Commission, on behalf of LGE Energy Corporation, in the matter of "Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.," Case No. 2003-00266, September 22, 2003.
- Before the Federal Energy Regulatory Commission, affidavit on behalf of The Detroit Edison Company in Docket No. ER03-262-000 on the appropriateness of transitional transmission rates to accommodate lost revenue of the New PJM companies, May 2003.
- Before the Federal Energy Regulatory Commission, Comments of Mathew J. Morey and Christina C. Forbes on Proposed Pricing Policy for Efficient Operation and Expansion of the Transmission Grid, Docket No. PL03-1-000, March 13, 2003.
- Before the Alberta Energy and Utilities Board, on behalf of Canadian Natural Resources Limited, File No. 1804-4, ESBI Alberta Ltd, Application No. 1248859, 2002 Congestion Management Principles Application.
- Before the California Public Utilities Commission on behalf of Edison Electric Institute, Phase II of the California Public Utilities Commission Rulemaking 99-10-025, Distributed Generation Standby Rate Design, 2000.
- Before the Michigan Public Service Commission on behalf of Consumers Energy Company, Case No. U-12134, Code of Conduct for Consumers Energy Company and the Detroit Edison Company, 2000.
- Before the Missouri Public Utility Commission on behalf of Edison Electric Institute on behalf of EEI and its member companies in Missouri Public Utility Commission Case No. EX-99-442 on affiliate rules for electric, gas and steam heating affiliates that included affiliate pricing, non-discriminatory access to essential facilities, access to books and records and audits, 1999.
- Before the Illinois Commerce Commission on behalf of Illinois Power Company, Case No. 99-0114 on Services and Facilities Agreement Between Illinois Power Company and Illinova Corporation, and other Illinova Entities, 1999.
- Before the Michigan Public Service Commission on behalf of Michigan Gas Utilities, Case No. U-11648, in the matter of the application of Michigan Gas Utilities for approval of transportation standards of conduct and complaint procedures, 1998.
- Before the Massachusetts Department of Telecommunications and Energy on behalf of Edison Electric Institute concerning whether to extend the affiliate transactions rules to utility affiliates participating in non-energy services or energy-related services markets, 1998.
- Before the Maine Public Utilities Commission on behalf of Edison Electric Institute, Docket No. 98-099, In the Matter of Joint Marketing and Advertising, 1998.

- Before the Maine Public Utilities Commission on behalf of Edison Electric Institute, Docket No. 98-457, Standards of conduct for transmission and distribution utilities and affiliated competitive electric providers," 1998.
- Before the Illinois Commerce Commission on behalf of Edison Electric Institute, Docket Nos. 98-0147 and 98-0148 (consolidated) on functional separation standards for utility distribution and merchant operations, 1998.
- Before the Illinois Commerce Commission on behalf of Edison Electric Institute, Docket Nos. 98-0013 and 98-0035 (consolidated) on affiliate codes of conduct and transaction rules, 1998.
- Before the Connecticut Department of Public Utility Control on behalf of Edison Electric Institute, Docket No. 98-06-11 on affiliate codes of conduct. This proceeding addressed nondiscriminatory access and cost allocation methods of preventing cross-subsidization, 1998.
- Before the Maine Public Utilities Commission on behalf of Edison Electric Institute, Docket No. 97-877 on the Maine Attorney General's report on market power in Maine, 1997.
- Before the Massachusetts Department of Telephone and Energy Supplied on behalf of Edison Electric Institute concerning affiliate codes of conduct and transaction rules, 1997.
- Before the Illinois Legislative Task Force on behalf of Edison Electric Institute concerning industry restructuring issues, 1997.
- Before the Mississippi Public Service Commission on behalf of Edison Electric Institute concerning industry restructuring issues, 1997.
- Before the Illinois Legislative Task Force on behalf of Edison Electric Institute concerning electric industry restructuring issues, 1996.
- Before the Kansas Legislature on behalf of Edison Electric Institute on electricity restructuring issues, 1996.
- Before the Illinois General Assembly, Citizens Energy Council, on behalf of Edison Electric Institute concerning electricity restructuring issues, 1996.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	**)**	
Corporation for a General Adjustment	**)**	
In Rates	**)**	**Case No. 2011-00036**

REDACTED

EXHIBIT MJM-2

OF

DR. MATHEW J. MOREY

RECEIVED

JUN 10 2011

PUBLIC SERVICE
COMMISSION

BREC Unit Operating Parameters and Fuel Costs

Generator Unit	Min Output	Max Output	Minimum Heat Rate	Maximum Heat Rate	Fuel Costs ($/MMBtu)		
	MW	MW	Btu/kWh	Btu/kWh	[redacted]	[redacted]	[redacted]
Wilson 1	245	417	11,560	10,864	[redacted]	[redacted]	[redacted]
Green 1	162	231	11,496	11,086	[redacted]	[redacted]	[redacted]
Green 2	161	223	11,506	11,149	[redacted]	[redacted]	[redacted]
Coleman 3	68	155	11,877	10,572	[redacted]	[redacted]	[redacted]
Coleman 1	65	150	11,856	10,576	[redacted]	[redacted]	[redacted]
Henderson 1	129	153	11,028	10,952	[redacted]	[redacted]	[redacted]
Henderson 2	130	159	11,249	11,170	[redacted]	[redacted]	[redacted]
Coleman 2	50	138	13,366	11,617	[redacted]	[redacted]	[redacted]
Reid 1	32	65	13,518	13,022	[redacted]	[redacted]	[redacted]
Reid CT	10	65	30,050	12,092	[redacted]	[redacted]	[redacted]

BREC Unit Variable O&M and Expected Forced Outage Rate

Generator Unit	Variable O&M			Expected Forced Outage Rate		
	2011	2012	2013	2011	2012	2013
Wilson 1	3.51	3.51	3.51	4.6%	4.3%	4.0%
Green 1	4.03	4.13	4.23	3.7%	3.3%	3.3%
Green 2	4.03	4.13	4.23	3.7%	3.3%	3.3%
Coleman 3	6.00	6.15	6.30	8.0%	8.0%	8.0%
Coleman 1	6.00	6.15	6.30	9.3%	7.0%	7.0%
Henderson 1	6.01	6.16	6.31	7.0%	7.0%	7.0%
Henderson 2	6.01	6.16	6.31	8.0%	8.0%	8.0%
Coleman 2	6.00	6.15	6.30	7.0%	7.0%	7.0%
Reid 1	6.00	6.15	6.30	10.0%	10.0%	10.0%
Reid CT	3.00	3.08	3.15	40.0%	40.0%	40.0%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	**)**	
Corporation for a General Adjustment	**)**	
In Rates	**)**	**Case No. 2011-00036**

EXHIBIT MJM-3

OF

DR. MATHEW J. MOREY

Net Margin Contribution – Smelters vs. Wholesale Market Sales – 2011 - 2013

	2011		2012		2013	Average
Sales To Smelters (MWh)	7,300,000		7,300,000		7,300,000	7,300,000
Revenue	$330,325,000		$383,688,000		$401,500,000	371,837,667
Average Operating Costs ($/MWh)	$25.89		$29.39		$30.94	$ 28.74
Total Operating Costs	$189,025,581		$214,579,259		$225,871,985	209,825,608
Net Margins	$141,299,419		$169,108,741		$175,628,015	162,012,059
	2011		**2012**		**2013**	**Average**
Wholesale Sales (MWh)	4,354,318		4,199,108		4,172,952	4,242,126
Average Market Prices	$38		$41		$42	$40
Revenues	197,324,418		204,860,736		214,727,866	205,637,673
Production Costs	122,368,664		126,262,017		132,628,572	127,086,418
Net Margins	74,955,754		78,598,719		82,099,294	78,551,256
Lost Margin	$ 66,343,665		$ 90,510,022		$ 93,528,721	$ 83,460,803

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	**)**	
Corporation for a General Adjustment	**)**	
To Rates	**)**	**Case No. 2011-00036**

AFFIDAVIT OF DR. MATHEW J. MOREY

Commonwealth of Virginia	)
	) ss:
Alexandria City	)

Dr. Mathew J. Morey, being first duly sworn, deposes and says that the facts and conclusions set forth in the attached statement are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as his sworn declaration in this proceeding.

M J Morey

Dr. Mathew J. Morey

Subscribed and sworn to before me, the undersigned notary public, this 20 th day of May 2011.

Notary Public

My Commission expires: Nov 30th 2014

OFFICIAL SEAL
ROBERT T. MORGAN
Notary Public
COMMONWEALTH OF VIRGINIA
My Commission Expires Nov. 30, 2014
ID #7012950

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	**Case No 2011-00036**
GENERAL ADJUSTMENT IN RATES	)	

DIRECT TESTIMONY

OF

CHARLES W. KING
SNAVELY KING MAJOROS & O'CONNOR, INC.

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CONSUMERS

May 24, 2011

DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

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

A. My name is Charles W. King. My business address is Suite 206, 8100 Professional Place, Landover, MD 20785. I am President Emeritus of Snavely King Majoros & O'Connor, Inc. ('Snavely King")

Q. FOR WHOM ARE YOU APPEARING IN THIS CASE?

A. I am appearing on behalf of the Kentucky Industrial Utility Consumers ("KIUC").

Q. HAVE YOU ATTACHED A SUMMARY OF YOUR BUSINESS AND EDUCATIONAL EXPERIENCE?

A. Yes. Attachment A hereto is a brief summary of my business and educational experience.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY AGENCIES?

A. Yes. Attachment B hereto is a 15-page listing of my appearances before regulatory agencies since the founding of Snavely King by the late Carl M. Snavely and me in 1970.

SUMMARY

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY IN THIS CASE?

A. The objective of my testimony in this case is to review and evaluate the depreciation rates proposed by the Big Rivers Electric Corporation ("Big Rivers") and, where appropriate, to recommend alternative rates. Big Rivers' depreciation rates are sponsored by Ted J. Kelly of the engineering firm of Burns & McDonnell ("B&M").

Q. WHAT HAS YOUR EVALUATION FOUND WITH RESPECT TO BIG RIVERS' DEPRECIATION RATES?

A. The depreciation rates proposed by B&M and adopted by Big Rivers are too high and result in excessive depreciation expense. The proposed rates are inconsistent with B&M's own analysis and are based on arbitrarily selected remaining plant lives.

Specifically, B&M estimated the retirement date and remaining life of each of Big Rivers' generating plants based on its engineering analysis. Those estimates are described in the narrative portion of B&M's report. In its workpapers, however, B&M also forecasts a variety of remaining lives for each plant based on an assumed number of remaining operating hours but under alternative assumptions as to the number of operating hours at each plant and the probability of plant life extensions. From this variety of remaining life estimates, B&M arbitrarily selected account remaining lives at the lower end of the spectrum. These remaining lives reflect plant life estimates that are inconsistent with and shorter than those described in the narrative portion of B&M's report and confirmed through data requests.

I have adopted B&M's confirmed retirement dates for each plant as the basis of my recommended depreciation rates I have weighted these unit remaining lives by the respective units' investment in each account to derive a dollar-weighted composite remaining life span for each of the five primary steam production plant accounts. I then apply B&M's interim retirement factors to arrive at the dollar-weighted remaining life of each account. Using these remaining lives, I calculate the KIUC recommended depreciation rates.

The remaining lives that I calculate from the plant life estimates in the B&M report are altogether different from and longer than the remaining lives that B&M shows in its summary tables. In short, B&M's remaining lives are inconsistent with its own report.

I also find that B&M has not employed the best depreciation practices in the process of estimating the interim retirement rates that it uses to develop the remaining lives for the respective plant accounts. Finally, I recommend that Big Rivers accrue depreciation based on rates specific to each account in each generating plant.

Q. HAVE YOU DEVELOPED DEPRECIATION RATES USING THE CORRECT ACCOUNT REMAINING LIVES?

A. Yes. I have. My recommended depreciation rates are set forth in the final column of Schedule 1 of Exhibit _____(CWK-1).

Q. WHAT IS THE DOLLAR IMPACT OF YOUR RECOMMENDED DEPRECIATION RATES?

A The dollar impact of my recommended depreciation rates is set forth in the bottom line of Schedule 1 of Exhibit_____(CWK-1). Based on April 30, 2010 plant balances, my rates reduce annual depreciation expense by approximately $1.56 million from its level under existing depreciation rates. My rates reduce Big Rivers' proposed depreciation expense by $5.63 million, again based on April 30, 2010 plant.

DEPRECIATION GENERAL

Q. WHAT IS DEPRECIATION?

A. In 1958, the National Association of Railroad and Utility Commissioners sanctioned the following definition of depreciation:

> "Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[1]

The second commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[2]

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[1] *Uniform System of Accounts for Class A and Class B Electric Utilities,* 1958, rev. 1962.
[2] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1.*

If depreciation can be defined in a single sentence, I would say that it is the process of recovering the initial investment in tangible capital assets, adjusted for salvage, in a systematic fashion over the useful service life of the plant, recognizing that utility plant is typically a group of investments.

Q. **CAN DEPRECIATION BE CALCULATED WITH PRECISION?**

A. No. Depreciation can no more be calculated with precision than can the required rate of return to equity investors. Both are developed from analyses that, while based on quantitative values, require considerable application of judgment. In the case of rate of return, that judgment pertains to the earnings expectations of investors as indicated by the stock market and corporate financial data. In the case of depreciation, the judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements.

Q. HOW DOES THIS JUDGEMENTAL CHARACTERISTIC OF DEPRECIATION INFLUENCE THE COMMISSION'S APPROACH TO THE SUBJECT?

A. The Commission must recognize that the development of depreciation rates is not a refined science subject to mathematical precision. Because depreciation analysts use judgment in their estimation of depreciation, the Commission must necessarily exercise its own judgment in assessing the rationale and data that underlie alternative depreciation rates. This is why, in this proceeding, the Commission must choose between two sets of depreciation rates that yield widely differing annual depreciation accruals.

Q. WHAT ARE THE BASIC PARAMETERS REQUIRED TO DEVELOP A DEPRECIATION RATE?

A. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the plant. The reciprocal of that number can be used as the depreciation rate.

However, because most utility depreciation is applied to accounts that are multiple units of plant, it is usually necessary to estimate the dispersion of retirements around an average service life. In the gas and electric utility industries, this dispersion is usually described in terms of "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the retirements are grouped around the average service life and whether they tend to occur more rapidly before, after or coincident with the average service life.

Another parameter that is typically included in the calculation of a depreciation rate is net salvage. Net salvage is the difference between the positive scrap value of the asset's material and the cost of dismantling and removing the asset when it is retired. It is expressed as a ratio to the cost of the asset and included as a subtraction (when salvage value exceeds removal cost) or an addition (when removal cost exceeds salvage) to the amount to be recovered in depreciation charges. With a few exceptions (e.g. vehicles, work equipment) most gas utility plant has a higher removal cost than its salvage value, so that the inclusion of net salvage in depreciation adds to the amount to be recovered.

Finally, virtually all major utilities, including Big Rivers, employ what is known as "remaining life depreciation." This procedure computes the depreciation rate by dividing the unrecovered net investment, adjusted for net salvage, by the estimated remaining years of the asset (or group of assets). It effectively ensures that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

Q. PLEASE ILLUSTRATE HOW THE PARAMETERS YOU HAVE JUST DESCRIBED ARE USED TO DEVELOP DEPRECIATION RATES?

A. Beginning with the simplest example, assume a single asset with a 20 year life. Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume that the asset is expected to have salvage value equivalent to 5 percent of its investment value. The depreciation rate declines:

$$\frac{1-.05}{20}=\frac{.95}{20}=4.7\%$$

Assume next that the cost of removing this asset amounts to 15 percent of its value. The depreciation rate increases:

$$\frac{1 - .05 + .15}{20} = \frac{1.10}{20} = 5.55\%$$

This is called a "whole life" rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional items of data: the original investment, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost \$1 million and that past depreciation charges have recovered \$400,000. This means that we have yet to recover \$600,000 in original cost, plus a negative net salvage (i.e. net cost of removal) amounting to 10% of the original cost, or \$100,000. The total amount yet to be recovered is thus \$700,000. Let us further assume that the asset is 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life years:

$$\frac{\$700{,}000}{10 \text{ years}} = \$70{,}000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this case:

$$\frac{\$70{,}000}{\$1{,}000{,}000} = 7\%$$

SERVICE LIFE ESTIMATION

Q. HOW DID B&M ESTIMATE THE SERVICE LIVES OF THE PRODUCTION PLANT ACCOUNTS?

A. B&M conducted a detailed engineering study of each of Big Rivers' generating units. Based on this study, B&M estimated the remaining operating hours of each unit and, using historical operating experience, forecast the remaining operating life of each unit. The sum of the remaining life and the expired life of each unit is then the estimated life span of the respective generating units. The common plant that is used by multiple units at a single location is assumed to survive until the retirement date of the longest-lived unit. These unit remaining lives were composited into account remaining lives using the percentage distribution of investment in each account among the five steam plants. A separate calculation developed the remaining lives of the accounts in the Robert A Reid Combustion Turbine.

These composited plant remaining life spans are not, however, the remaining lives of the respective accounts. That is because some plant will be retired and replaced before the entire unit retires. B&M assumed that the past rate of these "interim retirements" from each account will continue into the future. This assumption permitted B&M to forecast the annual interim retirements and the remaining proportion of plant that will survive until the terminal retirement of the account. From these forecasts B&M developed the estimate remaining life of each of the accounts. The remaining life is then divided into the remaining unrecovered investment to derive an annual accrual. When that accrual is divided by the gross plant, the result is the depreciation rate for the account.

Q. WHAT REMAINING LIVES DID B&M IDENTIFY FOR THE BIG RIVERS GENERATING PLANTS?

A. Superficially, the remaining plant lives would appear to be the remaining years between 2010, the year of the study, and the year identified in B&M's report as the retirement date of each plant. These retirement dates are found in the plant-by-plant discussion beginning at page II-4 of B&M's report. For example, B&M forecasts that the Wilson plant will survive until 2051, which is 41 years from 2010, the year of the study. Yet, when we turn to the Table II-2 (page II-3), the reported remaining unit life of Wilson is only 35.1 years. The same problem arises with each of the other plants. Indeed, in most cases, the longest-lived unit survives beyond the retirement date identified in B&M's narrative.

This internal inconsistency is further complicated when we examine B&M's workpapers. There, we find that B&M forecast no less than 12 remaining lives for each plant, most of which do not match the remaining life spans in Table II-2 or those that result from subtracting 2010 from the forecast plant retirement dates. These remaining lives reflect alternative assumption as to the operating hours and the likelihood that Big Rivers will conduct life extension programs, presumably through retrofitting and refurbishing of the piece-parts of the plants. I have presented these alternative plant life estimates in the first five columns of Schedule 2 of my Exhibit_____(CWK-1). They display a plethora of remaining life spans for each of the generating plants.

Q. HOW DID B&M IDENTIFY THE REMAINING LIVES OF THE RESPECTIVE PLANT ACCOUNTS?

A. B&M used the distribution of the investment in each account among the generating plants to composite the plant remaining lives into account remaining lives. Obviously, if B&M identified a variety of remaining lives for the generation plants, when it composited these remaining lives into account remaining life estimates, there was a similar variety of results. Those results are shown for three accounts in the final columns of Schedule 2. The bottom line of each column shows the account remaining lives that B&M actually used to calculate its depreciation rates. There is no clear indication from the report or any of the workpapers how B&M select those particular remaining lives from among the array that it calculated. The selection appears to have been totally arbitrary and skewed toward the lower end of the remaining life spectrum. But most importantly, the selection is inconsistent with the forecast plant retirement dates in B&M's own report.

Q. WHAT ARE THE REMAINING LIVES THAT ARE CONSISTENT WITH B&M'S FORECAST PLANT RETIREMENT DATES?

Confronted with this confusion, we inquired of B&M as to the specific dates that they expected each of the generating stations to retire. I have included the response as Exhibit_____(CWK-2). The retirement dates there correspond with the retirement dates identified in the narrative following page II-23 of B&M's report.

On Schedule 3 of Exhibit_____(CWK-1), I present these dates and show the consequent remaining lives as of 2010.

Q. HAVE YOU COMPOSITED THESE PLANT REMAINING LIVES INTO ACCOUNT REMAINING LIVES?

A. Yes. That compositing is shown on Schedule 4 of Exhibit_____(CWK-1). Big Rivers Continuing Property Record ("CPR") identifies each accounting entry by production unit using the location identifier. The production account entries in Big Rivers CPR use four digit codes with the last digit referring to the unit. For example, an entry in CPR with the account number 3122 would refer to Boiler Plant account for Coleman. These identifiers allowed us to obtain the gross investment and the accumulated depreciation reserve by account by plant.

The plant-by-plant gross investment amounts are set forth in column 1 of Schedule 3 of my exhibit. I then multiply each gross investments number by the remaining life of the plant (column 2) to derive the remaining life-years in column 3. When I divide the sum of these remaining life-years by the sum of investment in each account, I derive the dollar-weighted remaining life span years for each account.

Q. ARE THESE VALUES THE REMAINING LIVES OF EACH ACCOUNT?

A. No. As discussed earlier, the remaining life spans are not the remaining lives of the account because some plant will be retired from each account before the terminal retirement of the entire unit. In Schedules 5 through 9, I apply B&M's interim retirement factors to each year in the remaining life of each account. In the final retirement year, all of the remaining plant is retired. I then multiply the year-by-year retirements by their specific remaining lives and add those products at the bottom of each schedule. I then divide that sum of products by the current plant balance to derive the remaining life of the dollars in each account.

As can be seen by comparing my remaining lives with those in Table ES-1 of the B&M report, my computed remaining lives for the primary steam production accounts are all considerably longer than those used by B&M.

I should mention specifically the Long-lived Environmental Boiler Plant sub-account. B&M uses a much shorter life for this account than it does for the rest of the Boiler Plant account, presumably on the grounds that the caustic nature of the operations of these scrubbers results in a shorter life. But most of this equipment is still fairly new, so that if it survives until the retirement of the respective units, it will have experienced a shorter total service life. Furthermore, B&M states quite explicitly on page III-9 of its report that the remaining life of this equipment is constrained by the overall life of the plant in which it is located. I have therefore assumed that most of this account will survive until the terminal retirement of the respective generating units. Any retirements in the meantime should be picked up in the interim retirement adjustment.

Q. HAVE YOU USED YOUR REMAINING LIVES TO DEVELOP DEPRECIATION RATES?

A. Yes. Schedule 10 of Exhibit_____(CWK-1) shows the development of depreciation rates from the remaining lives I have calculated for the primary steam production accounts. It is a fairly straightforward process. Column 1 shows the net salvage factors identified by B&M. Their negative values means that the cost of removal is greater than the salvage value, so these percentages must be added to the amount to be recovered. Columns 2 and 3 are the original investment and the accumulated reserves taken from Big Rivers' CPR. Column 4 shows the amount that still must be recovered over the remaining life of the plant. It is the original investment marked up by the net salvage factor less the accumulated reserve. Column 5 lists the account remaining lives taken from Schedules 5 through 9. I have accepted B&M's estimate of the remaining life of the short-lived boiler plant sub-account. Column 6 shows the annual accrual, which is column 4 divided by the remaining lives, and column 7 shows the depreciation rates. Those rates are the result of dividing the annual accrual in column 6 by the gross investment in column 2.

Q. WHAT IS THE EFFECT OF YOUR REVISED DEPRECIATION RATES ON BIG RIVERS DEPRECIATION EXPENSE?

A. The effect is shown in Schedule 1 of my exhibit. Based on April 30, 2010 plant, my recommended depreciation rates result in an annual accrual of $28,393,890, which is a reduction of $5,634,669 from the $34,028,559 proposed by Big Rivers. This amount is $1,555,477 less than would be accrued using Big Rivers' present depreciation rates.

OTHER WEAKNESSES IN THE B&M STUDY

Q. ARE THERE OTHER WEAKNESSES IN THE B&M STUDY?

A. Yes. B&M calculates interim retirements by assuming that the past rate of retirements will continue into the future. That is, it assumes that the same percentage of plant will retire from each plant account each year. That is not the typical pattern of plant retirements. When plant is initially installed, there are very few retirements because it is all new. Then, as the plant ages, the shortest-lived components begin to wear out and are retired. Soon thereafter the rate of retirements accelerates, and the bulk of the plant may be retired fairly quickly. Then only the most long-lived components remain. Because these components are long-lived, the rate of retirements decreases. Often, it is many years beyond the average service life before all the components of plant placed in a given year retire.

This S-shaped pattern of retirements does not always occur in the same way. For some types of plant, the retirements are bunched closely around the average service life. For others, retirements stretch out over a long period both before and after the average service life. Sometimes the retirements accelerate at the greatest rate before the average service life; in others, the most accelerated retirements occur after the average service life.

These various patterns of retirement have been codified into a set of 38 "Iowa Curves," so named because they were developed at Iowa State University. The curves are classified as "L" for left-modal curves (most rapid rate of retirement before the average service life), "R" for right-modal curves (most rapid retirements after the average life) and "S" for symmetrical retirements. There are also "O" curves where a given percentage of plant retires each year.

B&M effectively assumes that all Big Rivers' plant retires based on an "O" curve. This almost certainly is not the case. Had B&M attempted to fit the pattern of retirements from each account to the Iowa curves, it no doubt would have come up with different interim retirement rates – rates that more accurately reflect the likely pattern of future retirements.[3]

I cannot say whether the forecast interim retirements would have been more or less than assumed by B&M, only that they would have been different and more accurate.

OTHER RECOMMENDATIONS

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS?

A. Yes. I recommend that Big Rivers abandon the practice of applying account average depreciation rates to all production plants and instead apply separate depreciation rates to each account within each generating station. While this recommendation requires a greater number of calculations, it is a more accurate way to charge depreciation in as system where each generating plant has its own discrete service life and remaining life.

From my experience, this is the typical procedure used by electric generating utilities.[4]

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes. It does.

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[3] The fitting of experienced retirement patterns to Iowa curves requires a fairly sophisticated computer program. It may be that B&M does not have the necessary software.

[4] Within Kentucky, for example, see Case 2007-00564, Application of Louisville Gas and Electric Company to File Depreciation Study, and Case 2006-00236, Application of East Kentucky Power Cooperative, Inc., for Approval of a Depreciation Study. In both of these cases, the companies calculated depreciation rates on a plant account basis by individual generating unit.

Experience

Snavely King Majoros O'Connor & Lee, Inc. Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. and Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, costs earnings and depreciation.

Mr. King has testified in electric, gas and water utility cases on virtually every aspect of regulation, including cost of capital, revenue requirements, depreciation, cost allocation and rate design. Mr. King is one of the nation's leading authorities on utility depreciation practices, having testified on this subject in several dozen cases before state regulatory bodies.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations. Mr. King directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

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Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
AK	Exxon USA	P-89-1,2	Trans Alaska Pipeline System	October 18, 1990
AZ	Arizona Corporation Commission	U-1345-I	Arizona Public Service Co.	December 16, 1980
	Arizona Retailers Association	U-1345-II	Arizona Public Service Co.	January 15, 1981
CA	California Retailers Association	57666	Pacific Gas & Electric Co.	March 6, 1978
	California Retailers Association	57602	Southern California Edison	April 25, 1978
	California Retailers Association	59351	Pacific Gas & Electric Co.	June 12, 1981
	California Retailers & California Manufacturers	59351	Southern California Edison	May 20, 1982
	California Retailers Association	61138	Southern California Edison	May 28, 1982
CO	U. S. Department of Defense	I&S 1100	Colorado Springs (Elec)	June 14, 1977
	J.C. Penney Company	5693	All Electric Utilities	March 8, 1978
	U.S. Department of Defense	I&S 1339	Colorado Springs DPU (Gas)	October 18, 1979
	U. S. Department of Defense	I&S 1540	Colorado Springs DPU (Gas)	February 9, 1982
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Gas)	September 30, 1984
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	June 6, 1985
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	May 19, 1986
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	June 30, 1987
CT	Retailers Merchants Association	72-0204	Various Electric Utilities	July 22, 1976
	Division of Consumer Counsel	76-0604,5	CL&P and HELCO	November 10, 1977
	Public Utilities Control Auto	78-0303	Bridgeport Hydraulic Co.	(none)
	Division of Consumer Counsel	80-0403,4	CL&P and HELCO	August 11, 1980
	Division of Consumer Counsel	81-0413	United Illuminating Company	July 20, 1981
	Division of Consumer Counsel	81-0602,4	CL&P and HELCO	October 5, 1981
	Division of Consumer Counsel	82-0701	CL&P	September 28, 1982
	Coalition of Hotels, Alloys & Retailers	85-10-22	CL&P	(none)
	Coalition of Hotels, Alloys & Retailers	87-07-01	CL&P	April 25, 1988

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
DC	D.C. People's Counsel	685	Potomac Electric Power Company	March 6, 1978
	D.C. People's Counsel	715	Potomac Electric Power Company	(none)
	D.C. People's Counsel	725	Potomac Electric Power Company	April 4, 1980
	D.C. People's Counsel	737	Potomac Electric Power Company	January 1, 1981
	Washington Metro Area Transit Authority	748	Potomac Electric Power Company	June 26, 1981
	Washington Metro Area Transit Authority	758	Potomac Electric Power Company	December 15, 1981
	D.C. People's Counsel	785	Potomac Electric Power Company	September 21, 1982
	Washington Metro Area Transit Authority	759	Potomac Electric Power Company	March 29, 1984
	D.C. People's Counsel	685 Remand	Potomac Electric Power Company	June 10, 1985
	D.C. People's Counsel	905	Potomac Electric Power Company	August 20, 1991
	D.C. People's Counsel	912	Potomac Electric Power Company	May 7, 1992
	D.C. People's Counsel	834, III	Potomac Electric Power Company	May 22, 1992
	D.C. People's Counsel	917	Potomac Electric Power Company	September 24, 1992
	D.C. People's Counsel	922	Washington Gas Light Company	June 15, 1993
	D.C. People's Counsel	929	Potomac Electric Power Company	December 16, 1993
	D.C. People's Counsel	934	Washington Gas Light Company	Filed April 22, 1994
	D.C. People's Counsel	939	Potomac Electric Power Company	March 16, 1995
	D.C. People's Counsel	917	Potomac Electric Power Company	April 16, 1995
	D.C. People's Counsel	951	Potomac Electric Power Company	February 20, 1997
	D.C. People's Counsel	945	Potomac Electric Power Company	September 29, 1999
	D.C. People's Counsel	847	Washington Gas Light Company	June 27, 2001
	D.C. People's Counsel	989	Washington Gas Light Company	May 22, 2002
	D.C. People's Counsel	1016	Washington Gas Light Company	September 23, 2003
	D.C. People's Counsel	1053	Potomac Electric Power Company	June 27, 2007
DE	Delaware PSC Staff	94-164	Artesian Water Company	Filed March 10, 1995
	Delaware PSC Staff	94-149	Wilmington Suburban Water Company	March 10, 1995
	Delaware PSC Staff	04-152	Tidewater Utilities Company	Filed July 26, 2004
FL	Florida Retail Federation	790593-EU	All Electric Utilities	March 5, 1981
	Florida Retail Federation	810002-EU	Florida Power and Light Company	July 23, 1981
	Florida Retail Federation	820097-EU	Florida Power and Light Company	September 22, 1982
	Florida Retail Federation	820097-EU	Florida Power and Light Company	April 11, 1983
	Florida Retail Federation	830012-EU	Tampa Electric Company	August 19, 1983
	Florida Retail Federation	830465-EI	Florida Power and Light Company	April 19, 1984
	Florida Retail Federation	830465-EI	Tampa Electric Company	(none)

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State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
GA	Georgia Retail Federation	3270-U	Georgia Power Company	September 3, 1981
	Georgia Public Service Commission	4007-U	Georgia Power Company	August 21, 1991
	Georgia Public Service Commission	4384-U	All Electric Utilities	August 1, 1993
	Georgia Public Service Commission	4755-U	Georgia Power Company	January 25, 1994
	Georgia Public Service Commission	4697-U	All Utilities	May 10, 1994
	Georgia Public Service Commission	9355-U	Georgia Power Company	November 4, 1998
	Georgia Public Service Commission	14000-U	Georgia Power Company	October 23, 2001
	Georgia Public Service Commission	14618-U	Savannah Electric & Power Company	March 27, 2002
	Georgia Public Service Commission	14311-U	Atlanta Gas Light Company	April 8, 2002
	Georgia Public Service Commission	17066-U	Georgia Power Company	July 31, 2003
	Georgia Public Service Commission	18300-U	Georgia Power Company	October 26, 2004
	Georgia Public Service Commission	18638-U	Atlanta Gas Light Company	March 14, 2005
	Georgia Public Service Commission	19758-U	Savannah Electric & Power Company	March 29, 2005
	Georgia Public Service Commission	20298-U	Atmos Energy Corp.	October 11, 2005
	Georgia Public Service Commission	25060-U	Georgia Power Company	Filed October 22, 2007
	Georgia Public Service Commission	27163	Atmos Energy Corp.	August 16, 2008
HI	Public Utilities Department	2793	All Electric Utilities	February 14, 1978
	Hawaii Consumer Advocate	4536	Hawaiian Electric Company	February 1, 1983
IL	Illinois Retail Merchants Association ("IRMA"/ Chicago Bldg. Mgrs. Association ("CBMA")	76-0698	Commonwealth Edison	June 22, 1977
	IRMA/CBMA	76-0568	All Electric Utilities	(none)
	IRMA/CBMA	80-0546	Commonwealth Edison	March 5, 1981
	IRMA/CBMA	82-0026	Commonwealth Edison	July 22, 1982
	IRMA/CBMA	83-0537	Commonwealth Edison	March 19, 1984
	IRMA/CBMA	87-0427	Commonwealth Edison	March/April 22, 1988
	IRMA/CBMA	90-0169	Commonwealth Edison	October 29, 1990
	City of O'Fallon, IL	02-0690	Illinois-American Water Company	Filed Feb.5, Apr.11,2003
IN	Indiana Retail Council	35780-S2	N. ind. Public Service co.	June 1, 1980
	Indiana Retail Council	35780-S1	Public Service of Indiana	October 15, 1980
	Indiana Retail Council	36318	Public Service of Indiana	May 4, 1982
KS	J.C. Penney Company	115,379-U	All Kansas Utilities	January 22, 1981

State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
KY	Seven Kentucky Retailers	7310	Louisville Gas & Electric Co.	April 25, 1979
KY	Attorney General of Kentucky	2002-145	Columbia Gas of Kentucky	Filed August 8, 2002
KY	Attorney General of Kentucky	2003-252	Union Heat Light & Power Co.	September 30, 2003
KY	Attorney General of Kentucky	2004-67	Delta Gas Company	August 18, 2004
KY	Attorney General of Kentucky	2006-00646	Atmos Energy Corp.	Filed April 27, 2007
KY	Attorney General of Kentucky	2007-00008	Columbia Gas of Kentucky	Filed June 12, 2007
KY	Attorney General of Kentucky	2007-00089	Delta Gas Company	Filed August 14, 2007
MA	Coalition of Municipalities	20279	Western Massachusetts Electric	March 19, 1980
MA	Coalition of Municipalities	557/558	Western Massachusetts Electric	May 14, 1981
MA	Coalition of Municipalities	957	Western Massachusetts Electric	March 9, 1982
MA	Coalition of Municipalities	1300	Western Massachusetts Electric	January 1, 1983
MA	Coalition of Municipalities	85-270	Western Massachusetts Electric	March 26, 1986
MD	Maryland People's Counsel	6977	Washington Gas & Light Company	September 17, 1976
MD	Maryland People's Counsel	6814	Potomac Electric Power Company	
MD	Maryland People's Counsel	6807	All Electric Utilities	September 1, 1977
MD	Maryland People's Counsel	6882	Baltimore Gas & Electric Company	(none)
MD	Maryland People's Counsel	6985	Baltimore Gas & Electric Company	September 28, 1976
MD	Maryland People's Counsel	7070	Baltimore Gas & Electric Company	December 20, 1976
MD	Maryland People's Counsel	7149	Potomac Electric Power Company	April 18, 1978
MD	Maryland People's Counsel	7163	All Electric Utilities	January 17, 1979
MD	Maryland People's Counsel	7236	Delmarva Power & Light Company	October 23, 1978
MD	Retail Merchants of Baltimore	7397	Baltimore Gas & Electric Company	June 20, 1980
MD	Maryland People's Counsel	7427	Delmarva Power & Light Company	September 8, 1980
MD	Maryland People's Counsel	7574	Baltimore Gas & Electric Company	December 2, 1981
MD	Maryland People's Counsel	7597	Potomac Electric Power Company	February 18, 1982
MD	Organization of Consumer Justice	7604	Potomac Electric Power Company	April 20, 1982
MD	Maryland People's Counsel	7588	Baltimore Gas & Electric Company	October 19, 1982
MD	Maryland People's Counsel	7663	Potomac Electric Power Company	November 22, 1982
MD	Retail Merchants of Baltimore	7685	Baltimore Gas & Electric Company	April 12, 1983
MD	Genstar Stone Products, et al.	7878	Potomac Electric Power Company	December 9, 1985
MD	Industrial Intervenors	7878	Potomac Electric Power Company	June 28/July 1986
MD	Maryland People's Counsel	7983	Baltimore Gas & Electric Company	March 4, 1987
MD	Giant Foods, Inc.	8855	Baltimore Gas & Electric Company	January 8, 2003
MD	Maryland People's Counsel	9036	Baltimore Gas & Electric Company	September 29, 2005
MD	Maryland People's Counsel	9092	Potomac Electric Power Company	April 16, 2007
MD	Maryland People's Counsel	9093	Delmarva Power & Light Company	April 9, 2007
MD	Maryland People's Counsel	9104	Washington Gas & Light Company	August 23, 2007
MD	Maryland People's Counsel	9096	Baltimore Gas & Electric Company	September 24, 2007
MD	Maryland People's Counsel	9103	Washington Gas & Light Company	filed December 21, 2007
MD	Maryland People's Counsel	9159	Columbia Gas Company	January 6, 2009
MD	Maryland People's Counsel	9192	Delmarva Power & Light Company	September 25, 2009
MD	Maryland People's Counsel	9217	Potomac Electric Power Company	April 8, April 30 May 7, 2010
MD	Maryland People's Counsel	9237	Baltimore Gas & Electric Company	July 10, Aug 30, 2010

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State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
MI	General Services Administration	U-10102	Detroit Edison Company	March 22, 1993
	Michigan Attorney General	U-11722	Detroit Edison Company	November 6, 1998
	Michigan Attorney General	U-11772	Consumers Energy/Detroit Edison	November 16, 1998
	Michigan Attorney General	U-11495	Detroit Edison Company	December 8, 1999
	Michigan Attorney General	U-11956	Consumer Energy/Detroit Edison	December 15, 1999
	Michigan Attorney General	U-12505	Consumers Energy Company	September 7, 2000
	Michigan Attorney General	U-12478	Detroit Edison Company	October 5, 2000
	Michigan Attorney General	U-12639	Consumers Energy/Detroit Edison	July 18, 2001
	Michigan Attorney General	U-13000	Consumers Energy Company	January 29.2002
	Michigan Attorney General	U-13380	Consumers Energy Company	September 9, 2002
	Michigan Attorney General	U-13715	Consumers Energy Company	April 24, 2003
	Michigan Attorney General	U-13808	Detroit Edison Company	Dec 12, 2003; Jan 30, Mar 5, 04
	Michigan Attorney General	U-12999	Consumers Energy Company	March 10, 2004
	Michigan Attorney General	U-13898,9	Michigan Consolidated Gas Co.	August 23, 2004
	Michigan Attorney General	U-14201	Detroit Edison Company	Filed December 5, 2004'
	Michigan Attorney General	U-14274	Consumers Energy Company	Filed February 15, 2005
	Michigan Attorney General	U-14148	Consumers Energy Company	Filed March 2, 25, 2005
	Michigan Attorney General	U-14399	Detroit Edison Company	July 29, 2005
	Michigan Attorney General	U-14428	Detroit Edison Company	September 7, 2005
	Michigan Attorney General	U-14292	All Michigan Utilities	September 27, 2005
	Michigan Attorney General	U-13808-R	Detroit Edison Company	November 7, 2005
	Michigan Attorney General	U-14547	Consumers Energy Company	Nov.7, 2005; Mar. 22, 2006
	Michigan Attorney General	U-14701	Consumers Energy Company	March 21, 2006
	Michigan Attorney General	U-14526	Consumers Energy Company	April 11.2006
	Michigan Attorney General	U-14561	All Gas Distribution Utilities	June 1, 2006
	Michigan Attorney General	U-15002	Detroit Edison Company	December 8, 2006
	Michigan Attorney General/ABATE	U-15245	Consumers Energy Company	December 11, 2007
	Michigan Attorney General	U-15417	Detroit Edison Company	April 2, 2008
	Michigan Attorney General/ABATE	U-15244	Detroit Edison Company	July 15, 2008
	Michigan Attorney General/ABATE	U-15506	Consumers Energy Company	September 12, 2008
	Michigan Attorney General	U-15002-R	Detroit Edison Company	October 16, 2008
	Michigan Attorney General	U-15645	Consumers Energy Company	April 27, July 30, 2009
	Michigan Attorney General	U-15768	Detroit Edison Company	July 9, July 30, 2009
	Louisiana Pacific Corp.	U-15981	Wisconsin Electric Power Co.	Dec 22, 2009; Jan 22, 2010
	Michigan Attorney General/ABATE	U-16180	Indiana-Michigan Electric Co.	July 1, 2010
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
	Missouri Public Counsel	ER-2006-0315	Empire District Electric Company	September 14, 2006
	Missouri Public Counsel	GR-2007-0003	Ameren UE (Gas)	Filed December 15, 2006
	Missouri Public Counsel	ER-2007-0002	Ameren UE (Electric)	March 22, 2007
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975

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	Client	Case		
		Case Number	Utility	
ND	North Dakota Public Service Commission	PU-400-00-521	Xcel Energy, Inc.	April 20, 2001
	North Dakota Public Service Commission	PU-399-01-186	Montana-Dakota Utilities (Electric)	February 25, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas)	October 7, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas Depr.)	Filed April 7, 2003
	North Dakota Public Service Commission	PU-399-03-296	Montana-Dakota Utilities (Electric)	Filed October 15, 2003
	North Dakota Public Service Commission	PU-04-97	Montana-Dakota Utilities (Gas)	Filed July 6, 2004
	North Dakota Public Service Commission	PU-06-525	Northern States Power (Gas)	Filed May 1, 2007
	North Dakota Public Service Commission	PU-07-776	Northern States Power (Electric)	June 25, 2008
	North Dakota Public Service Commission	PU-08-862	Otter Tail Power Company	April 6, 2009
NH	Business & Industry Association of N.H.	79-187-II	Public Service of N.H.	February 6, 1981
	Business & Industry Association of N.H.	80-260	Public Service of N.H.	February 5, 1981
	Business & Industry Association of N.H.	82-333	Public Service of N.H.	November 2, 1983
NJ	N.J. Retail Merchants Association	803-151	All New Jersey Utilities	March 31, 1981
	Department of Public Advocate	815-459	N.J. Natural Gas Company	(none)
	Resorts International Hotel, Inc.	8011-827	Atlantic City Sewerage Co.	(none)
	Dept. of Public Advocate	822-116	Atlantic City Electric Co.	August 11, 1982
	Dept. of Public Advocate	355-87	Elizabethtown Gas	June 9, 1987
	Dover Township Fire Chiefs	88-080967	Tom's River Water Company	February 22, 1989
NY	NY Council of Retail Merchants	26806	All Electric Utilities	February 3. 1976
	Metropolitan N.Y. Retail Council	27029	Consolidated Edison Company	(none)
	Metropolitan N.Y. Retail Council	27136	Long Island Lighting Company	July 1, 1977
	N.Y. Metro. Transit Authority	27353	Consolidated Edison Company	September 5, 1980
OH	Ohio Council of Retail Association	88-170-EL	Cleveland Elec. Illuminating	(none)
	Ohio Council of Retail Association	83-1529-EL	Cincinnati Gas & Electric	February 15, 1992
	Ohio Energy Group	08-936-EL-SSO	FirstEnergy Companies	Filed September 25, 2008

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State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
PA	Pennsylvania Retail Association	76-PRMD-7	All Electric Utilities	September 7, 1977
	Southeastern Pa. Transp. Authority	R-811626	Philadelphia Electric Company	December 11, 1981
	Eastern Penn Energy Users Group	R-822169	Penn. Power & Light Company	March/April 1983
	Eastern Penn Energy Association	R-842651	Penn. Power & Light Company	December 3, 1984
	Penn Business Utility User Group	R-850152	Philadelphia Electric Company	February 19, 1986
	Pennsylvania Office of Consumer Advocate	R-00016339	Pennsylvania-American Water Co.	September 19, 2001
	Pennsylvania Office of Public Advocate	R-2008-203269	Pennsylvania-American Water Co.	August 6, 2008; Sept.15, 2008
TN	Attorney General of Tennessee	07-00105	Atmos Energy Corp.	Filed August 21, 2007
	Attorney General of Tennessee	08-00039	Tennessee-American Water Co.	August 26, 2007
TX	Houston Retailers Association	5779	Houston Lighting Company	October 19, 1984
	Houston Retailers Association	6765	Houston Lighting Company	September 25, 1986
	Cities for Fair Utility Rates	8425/8431	Houston Lighting Company	April 25, 1989
UT	Div. Of Public Utilities Dept of Commerce	98-2035-33	Pacific Corp	Filed August 16, Sept 22, 1999
	Div. Of Public Utilities Dept of Commerce	05-057-T01	Questar Gas Company	May 17, 2006
	Div. Of Public Utilities Dept of Commerce	07-035-13	Rocky Mountain Power Co.	Filed October 15, 2007
VA	Consumer Congress of Virginia	19426	Virginia Electric Power Company	July 1, 1975
	Consumer Congress of Virginia	19960	Virginia Electric Power Company	September 19, 1978
	Va. Business Committee on Energy	PUE 7900012	Virginia Electric Power Company	February 25, 1981
	Virginia Pipe Trades Council	PUE 8900051	Old Dominion Electric Corp. &	October 31, 1989
WA	WA Attorney General - Public Counsel	UE-072300;UG-072301	Puget Sound Energy	Filed May 30, 2008
	WA Attorney General - Public Counsel	UE-080220	PacifiCorp	Filed August 15, 2008
	WA Attorney General - Public Counsel	UE-08416;UG-08417	Avista Utilities	September 19;October 10, 2008
WI	Wisconsin Merchants Federation	6630-ER-2	Wisconsin Electric Power Company	May 15, 1978

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State	Telecommunications Cases			Date
	Client	Case		
		Case Number	Utility	
AL	U.S. Department of Defense	24472	All Telephone Companies	June 14, 1995
AK	GCI Communications, Inc.	U-97-82,U-97-143	Alaska Communications Systems	Filed Feb 25, April 5, 2004
	GCI Communications, Inc.	U-05-46	Matanuska Telephone Association	October 28, 2005
AZ	Arizona Burglar & Fire Alarm Association	9981-E-	Mountain State Telephone	(none)
	Arizona Burglar & Fire Alarm Association	1051-80-64	Mountain State Telephone	
	Federal Executive Agencies	E-1051-88-146	Mountain State Telephone	(none)
	U.S. Department of Defense	T-01051B-99-0105	US WEST Communications	Filed July 26, Sept 8, 2000
	U.S. Department of Defense	T-01051B-10-0194	Qwest/CenturyTel	September 27, 2010
CA	Western Burglar & Fire Alarm Association	59849	Pacific Telephone & Telegraph	March 25, 1981
	Western Burglar & Fire Alarm Association	5984cont.	Pacific Telephone & Telegraph	June 23, 1982
	Western Burglar & Fire Alarm Association	A83-01-22	Pacific Telephone & Telegraph	June 29, 1983
	Western Burglar & Fire Alarm Association	A83-02-02	General Telephone of California	January 17, 1984
	Western Burglar & Fire Alarm Association	A82-11-07	Pacific Telephone & Telegraph	Jan. 18, Oct. 31, Nov 28, 1984
	Western Burglar & Fire Alarm Association	A85-01-034	Pacific Telephone & Telegraph	June 4, 1985, October 2, 1986
	Western Burglar & Fire Alarm Association	A87-01-02	General Telephone of California	October 22, 1987
	Western Burglar & Fire Alarm Association	A88-07-17019	Pac. Bell Tel. & GTE of CA.	January 23, 1989
	California Cellular Resellers	A.88-11-1040	All Cellular Carriers	August 11, 1989
	Federal Executive Agencies	1.87-11-033	All Telephone Companies	March 6-7, 1991
	California Cellular Resellers	1.88-11-040	All Cellular Carriers	August 19, 1991
	Cellular Services, Inc.	1.88-11-040	All Cellular Carriers	October 3, 1991
	Federal Executive Agencies	A92-05-004	Pacific Telephone & Telegraph	June 9, 1993
CO	U.S. Department of Defense	I&S 717	Mountain Bell Telephone Company	1972
	U.S. Department of Defense	I&S 1700	Mountain Bell Telephone Company	(none)
	U.S. Department of Defense	Appl.	Mountain Bell Telephone Company	September 18, 1986
	U.S. Department of Defense	I&S 1766	Mountain Bell Telephone Company	November 28, 1988
	Colorado Municipal League	Appl 36883	Mountain Bell Telephone Company	December 13, 1988
	U.S. Department of Defense	I&S 891-O82T	U.S. West Communications	February 21, 1990
	U.S. Department of Defense	905-544T	U.S. West Communications	July 17, 1991
	U.S. Department of Defense	90A-665T	U.S. West Communications	October 23, 1991
	U.S. Department of Defense	92M-039T	U.S. West Communications	February 24-24, 1992
	U.S. Department of Defense	92S-229T	U.S. West Communications	July 30-31, 1992
	U.S. Department of Defense	90A-665T	U.S. West Communications	November 6, 1996
	AT&T	96S-331T	U.S. West Communications	April 17, 1997
	U.S. Department of Defense	10A-150T	Qwest/CenturyTel	September 15, 2010

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State	Telecommunications Cases			Date
	Client	Case		
		Case Number	Utility	
CT	Connecticut Consumer Counsel	770526	Southern New England Telephone Co.	November 10, 1977
	CT Cellular Resellers Assn.	89-12-05	Southern New England Telephone Co.	(none)
	CT Cellular Resellers Coalition	94-03-27	Springwich Cellular/Bell Atlantic	May 16, June, 1994
	AT&T	AT&T/SNET Arbitration	Southern New England Telephone Co.	Filed October 28, 1996
	Connecticut Consumer Counsel	96-04-07	Southern New England Telephone Co.	February 10,1998
	Connecticut Consumer Counsel	00-07-17	Southern New England Telephone Co.	December 5, 2000
DC	D.C. People's Counsel	729	Chesapeake & Potomac Tel. Co.	May 13, 1980
	D.C. People's Counsel	798	Chesapeake & Potomac Tel. Co.	July 18, 1983
	General Services Administration	827	Chesapeake & Potomac Tel. Co.	May 7, 1985
	General Services Administration	854	Chesapeake & Potomac Tel. Co.	April 16, 1987
	General Services Administration	850	Chesapeake & Potomac Tel. Co.	October 7, 1991
	General Services Administration	926	Chesapeake & Potomac Tel. Co.	October 7, 1993
DE	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	April 1, 1985
	Federal Executive Agencies	86-20	Diamond State Telephone Co.	July 31, 1987
	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	March 8, 1988
FL	GTE Sprint Communications Company	720536-TP	All Telephone Companies	September 12, 1983
	Office of Public Counsel	Depr.Repre	Southern Bell	July 30, 1986
	Federal Executive Agencies	880069-TL	Southern Bell	July 21, 1988
	Federal Executive Agencies	880069-TL	Southern Bell	November 30, 1990
	Federal Executive Agencies	880069-TL	Southern Bell	February 11, 1992
GA	Georgia Attorney General	3893-U	Southern Bell Telephone Co.	January 8, 1990
	Federal Executive Agencies	3905-U	Southern Bell Telephone Co.	June 12, 1990
	Federal Executive Agencies	3987-U	Southern Bell Telephone Co.	February 13, 1992
	Georgia Public Service Commission	4018-U	Southern Bell Telephone Co.	Jan 14, Feb 10, 1993
HI	Hawaii Public Utility Commission	1871	Hawaiian Telephone Company	July 8, 1971
	Four Hawaii Counties	4588	Hawaiian Telephone Company	December 15, 1983
	Department of Defense	7579	Hawaiian Telephone Company	April 26, 1994
	Department of Defense	94-0093	Oceanic Communications	March 13, 1995
	Department of Defense	7702	All Communications Carriers	June 2, 1995
	Department of Defense	94-0298	GTE Hawaiian Telephone Company	May 7, 1996
	Department of Defense	7720	Verizon-Hawaii	November 15, 2000

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State	Telecommunications Cases			Date
	Client	Case		
		Case Number	Utility	
ID	U.S. Department of Energy	U-1000-63	Mountain Bell Telephone Co.	May 16, 1983
	U.S. Department of Energy	U-1000-70	Mountain Bell Telephone Co.	March 6, 1984
IL	Illinois Alarm Companies	79-0143	Illinois Bell Telephone	September 26, 1979
	Attorney General of Illinois	81-0478	Illinois Bell Telephone	December 28, 1981
	GTE Sprint Communications Co.	83-0142	All Telephone Companies	August 4, 1983
	Federal Executive Agencies	89-0033	Illinois Bell Telephone	June 12, 1989
	Federal Executive Agencies	09-0268	Verizon-Frontier Sale	Oct.20, Dec.14, 2009
KS	State Corporation Commission	Depr. Repr.	Southwestern Bell	May 12-14, 1986
	Federal Executive Agencies	166.856-U	Southwestern Bell	November 7, 1989
	Federal Executive Agencies	190, 492	All Telephone Companies	November 4, 1994
KY	Kentucky Cable Telecommunications Assn.	2000-414	Blue Grass Energy Cooperative	January 11, 2001
	Kentucky Cable Telecommunications Assn.	2000-39	Cumberland Valley Electric, Inc.	January 11, 2001
MD	Maryland People's Counsel	6813	C&P Telephone Company	1975
	Maryland People's Counsel	6881	C&P Telephone Company	December 17, 1975
	Maryland People's Counsel	7025	C&P Telephone Company	March 15, 1975
	Maryland People's Counsel	7467	C&P Telephone Company	October 20, 1981
	Federal Executive Agencies	7851	C&P Telephone Company	March 20, 1985
	Federal Executive Agencies	8106	C&P Telephone Company	May 9, 1988
	Federal Executive Agencies	8274	C&P Telephone Company	August 2, 1990
MI	Michigan Attorney General	U-8911	Michigan Bell Telephone Co.	November 7, 1988
	Michigan Attorney General	U-9553	AT&T Communications/MCI	December 4, 1990
MN	GTE Sprint Communications Co.	83-102-HC	All Telephone Companies	August 5, 1983
	U.S. Department of Defense	87-021-BC	Northwest Bell Telephone Co.	(none)

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State	Telecommunications Cases			Date
	Client	Case		
		Case Number	Utility	
MO	GTE Sprint Communications Co.	TR83-253	Southwestern Bell Tel. Co.	September 5, 1983
MO	Federal Executive Agencies	TC-89-14	Southwestern Bell Tel. Co.	(none)
MO	Federal Executive Agencies	TO-89-56	Southwestern Bell Tel. Co.	November 7, 1990
MS	Federal Executive Agencies	U-5453	South Central Bell Tel. Co.	May 15, 1990
NJ	Department of Public Advocate	Depr.Repr.	N.J. Bell Telephone Company	Mar-79
NJ	Department of Public Advocate	815-458	N.J. Bell Telephone Company	October 15, 1981
NJ	Department of Public Advocate	Depr.Repr.	N.J. Bell Telephone Company	March 1, 1982
NJ	Department of Public Advocate	Depr.Repr.	N.J. Bell Telephone Company	February 1, 1985
NJ	Department of Public Advocate	T092030358	N.J. Bell Telephone Company	September 30, 1992
NJ	Department of Public Advocate	TMO05080739	United Telephone Co. of New Jersey	January 5,2006
NM	New Mexico Corporation Commission	1032	Mountain Bell Telephone Co.	November 14, 1983
NM	New Mexico Corporation Commission	86-151-TC	General Telephone of Southwest	February 5, 1987
NV	Prime Cable of Las Vegas	95-8034/8035	Central Telephone - NV	Filed November 22, 1995
NV	Prime Cable of Las Vegas	96-9035	Sprint/Centel, Nevada Bell	June 2, 1997
NY	Holmes Protection, Inc.	27350	New York Telephone Company	October 17, 1978
NY	Holmes Protection, Inc.	27469	New York Telephone Company	May 17, 1979
NY	5 Alarm Companies	27710	New York Telephone Company	July 24, 1980
NY	GTE Sprint Communications Co.	28425	All Telephone Companies	July 8, 1983
PA	City of Philadelphia	R-832316	Pennsylvania Bell Telephone	September 20, 1983
SC	Office of Consumer Advocate	Depr.Repr.	Southern Bell	July 1, 1986
SC	Office of Consumer Advocate	86-511-C	Southern Bell	December 11, 1986
SC	Office of Consumer Advocate	86-541-C	General Telephone of South	April 8, 1987
SC	Office of Consumer Advocate	Depr.Repr.	Southern Bell	July 10, 1989
SC	Office of Consumer Advocate	89-180-C	ALLTEL of South Carolina	September 26, 1989
SC	U.S. Department of Defense	2009-220-C	Verizon/Frontier Communications	August 27, 2009

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date
	Client	Case		
		Case Number	Utility	
TX	U.S. Department of Defense	8585/8218	Southwestern Bell Telephone Co.	(none)
UT	U.S. Department of Defense	10-049-16	Qwest/CenturyTel	August 30, 2010
VA	U.S. Dept. Of Defense, GSA, et	19696	C&P Telephone Company	October 6, 1976
	Federal Executive Agencies	PUC 890014	All Telephone Companies	February 13, 1989
VI	V.I. Department of Commerce	205	Virgin Islands Telephone Co.	April 29, 1980
	V.I. Public Service Commission	341	Virgin Islands Telephone Co.	March 20, 1991
WA	U.S. Department of Defense	U-72-39	Pacific Northwest Bell	1973
	U.S. Department of Defense	U-87-796-T	Pacific Northwest Bell	December 20, 1983
	U.S. Department of Defense	U-88-20524	Pacific Northwest Bell	November 8, 1988
	U.S. Department of Defense	U-89-2698-F	US West Communications	November 28, 1989
	WA Attorney General/TRACER	UT-940641	US West Communications	Filed October 14, 1994
	U.S. Department of Defense	UT-941464	US West Communications	June 22, 1995
	U.S. Department of Defense		US West Communications	January 22, 1996
	WA Attorney General/TRACER	UT-951425	US West Communications	Filed June 23, 1997
	WA Attorney General/TRACER	UT-961632	GTE Northwest, Inc	July 29, 1997
	U.S. Department of Defense	UT-021120	Qwest Communications	May 22, 2003
	WA Attorney General/WeBTEC/AARP	UT-040788	Verizon Northwest, Inc.	August 12, 2004
	WA Attorney General	UT-040520	Verizon Northwest, Inc.	February 2, 2005
	WA Attorney General	UT-050814	Verizon - MCI Merger	November 2, 2005
	U.S. Department of Defense	UT-090842	Verizon-Frontier Sale	Nov.3,2009;Jan 28, 2010
	U.S. Department of Defense	UT-100820		September 27, 2010
WV	U.S. Department of Defense	09-0871-T-PC	Verizon-Frontier Sale	November 16, 2009
WI	GTE Sprint	6720-TR-38	All Telephone Companies	October 20, 1983
	Wisconsin Consumers Utility Board	2055-TR-102	CenturyTel of Central Wisconsin	June 26, 2002
	Wisconsin Consumers Utility Board	5846-TR-102	Telephone USA, LCC	June 26, 2002

CHARLES W. KING
Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date
Federal Communications Commission			
Department of Defense	16020	Consat Rate of Return	1973
Airline Parties	16258	Bell System Rates	July 22, 1968
Airline Parties	18128	TELPAK	3/22, 10/15 1971, Feb. 22, 1972
National Data Corporation	19989	WATS	(none)
Press Wire Services	19919	Private Line Rates	(none)
Aeronautical Radio	20814	Private Line Rates	October 5, 1978
Department of Defense	20690	1,544 Mbps Service	January 30, 1979
State of Hawaii	21263	Interstate Separation	February 7, 1979
International Record Carriers	CC78-97	Telex/TWX Rates	March 6, 1980
ITT World Communications	CC84-633	Rate of Return	(none)
Aeronautical Radio	*CC78-72*	*Access Line Charges*	*(none)*
MCI	CC84-800	Rate of Return	(none)
Ind. Data Com. Mfg. Assn.	CC85-26	AT&T Accounting Plan	(none)
Tymnet, Inc.	ENF84-22	Packet Switching Costs	(none)
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 7/29/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 8/23/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 2/21/95
Nuclear Regulatory Commission			
Fauquier League for Environment Protection	50-328 50-329	Va. Electric Power Co.	1976
Postal Rate Commission			
Association of Third Class Mail Users	R71-1	Rates	1970
Dow Jones & Company	R72-1	Rates	1972
Dow Jones & Company	R74-1	Rates	September 13, 1974
Dow Jones & Company	MC76-2	Rate Structure	January 6, 1979
Dow Jones & Company	MC79-3	Rate Structure	September 12, 1979
Dow Jones & Company	R80-1	Rates	November 25, 1980
Warshawsky & Company	C82-1	Rate Structure	(none)
Dow Jones & Company	R84-1	Postal Costs	June 14, 1984
Dow Jones & Company	R87-1	Rate Structure Costs	November 2, 1987
Dow Jones & Company	R90-1	Rate Structure Costs	Sept 12, Oct 10, 1990
Dow Jones & Company	MC91-1	Pre-barcoding Discounts	November 19, 1991
Dow Jones & Company	MC91-3	Palletization Discounts	March 2, 1992

CHARLES W. KING
Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date
U.S. Congress			
National Retail Merchants Association	House/Senate Hearings	Electric Rate Reform Legislation	1976, 1977 & 1979
National Wireless Resellers Association	House Commerce Committee	Interconnection & Resale of Wireless Services	October 12, 1995
Federal Maritime Commission			
State of Hawaii	71-18	Ocean Shipping Rates	October-71
Foss Alaska Line	79-54	Barge Rate Increase	July 1979
Palmetto Shipping and Stevadoring	85-20	Vessel Charge Liability	October 27, 1986
Interstate Commerce Commission - Surface Transportation Board			
Western Coal Traffic League	Ex Parte 349	R.R. Rate Increase	May-76
Western Coal Traffic League	Ex Parte 357	R.R. Rate Increase	Oct-78
Western Coal Traffic League	Ex Parte 375 (Sub1)	R.R. Rate Increase	June 1, 1980
Arkansas Power & Light Co.	37276	Cost of Capital	(none)
Central Illinois Light Co.	37450	Cost of Capital	March 10, 1981
Western Coal Traffic League	Ex Parte 347	Costing Methods	(none)
Snavely King Majoros O'Connor & Lee, Inc.	Ex Parte 664	Cost of Capital	December 8, 2006
Williams Energy Services, Inc	Ex Parte 582, Sub 1	Rail Merger Guidelines	April 5, 2001
Civil Aeronautics Board			
Thomas Cook, Inc.	36595	Air Fare Deregulation	(none)
Copyright Royalty Tribunal			
Public Broadcasting Service	88-2-86CD	Television Valuation	(none)

CHARLES W. KING
Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date
Federal Energy Regulatory Commission			
Exxon USA	OR89-2-000	Pipeline Quality Bank	October 18, 1990
Consumer Advocates of DE,DC,OH,MD,NJ,PA,WV,VA	ER08-386-000	Electric Transmission Cost of Equity	March 26, 2008
Consumer Advocates of DE,DC,OH,MD,NJ,PA,WV	ER08-23-000	Electric Transmission Cost of Equity	May 21, 2008
Maryland Office of People's Counsel	ER08-686-01	Electric Transmission Cost of Equity	April 7, 2008; July 8, 2008,
Maryland Office of People's Counsel	ER08-23-000	Electric Transmission Cost of Equity	May 21, 2008
Maryland Office of People's Counsel	ER08-1329	Electric Transmission Cost of Equity	August, 2008
Louisiana Public Service Commission	ER09-1224	Depreciation	March 2010
Maryland Office of People's Counsel	ER10-355	Electric Transmission Cost of Equity	December 22, 2010
Canadian Transport Commission			
Rail Costing Inquiry, 1967-1969 Telecommunications Costing Inquiry, 1972-1975			

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	Case No 2011-00036

EXHIBITS

OF

CHARLES W. KING

Big Rivers Electric Corporaton

Annual Depreciation Expense Based on April 30, 2010 Plant in Service

Account	Description	April 30, 2010 Plant Balance	Recommended Depreciation Rate	Annual Depreciation Expense KUIC Recommended	Existing BREC Rates	Proposed BREC Rates
		(1)	(2)	(3)	(4)	(5)
340	Land	475,968				
311	Structures	124,375,974	1.17%	1,459,643	2,126,829	1,717,828
312	Boiler Plant	667,206,536	1.55%	10,371,572	11,942,997	12,543,396
312 A-K	Boiler Plant - Env Compl	574,184,346	1.97%	11,326,090	10,852,084	13,074,185
312 L-P	Short-Life Production Plant -Environmental	3,208,938	19.31%	619,761	60,649	648,949
312 V-Z	Short-Life Production Plant -Other	868,755	19.31%	167,788	16,419	125,054
314	Turbine	225,272,354	1.55%	3,485,620	3,739,521	4,309,293
315	Electric Eqpt	60,355,721	1.09%	655,003	965,692	1,202,952
316	Misc Eqpt	3,014,912	3.79%	114,328	55,173	113,919
341	CT - Structures	154,233	1.17%	1,804	3,563	1,804
342	CT - Fuel Holders & Access.	1,436,912	9.10%	130,751	33,336	130,751
343	CT - Prime Movers	475,968	3.02%	14,369	121,422	148,408
344	CT - Generators	4,915,886	0.50%	24,562	24,596	5,511
345	CT - Access. Elec. Eqpt.	1,102,964	2.05%	22,601	7,085	6,510
	Subtotal	1,667,049,464		28,393,890	29,949,367	34,028,559
	Difference from KUIC Recommendation				**(1,555,477)**	**(5,634,669)**

Sources
(1) AG 1-104 - "Deprec Summary 2010-12-16 FINAL.xls"
(2) Schedule 10
(3) Col (1)*Col (2)
(4) & (5) AG 1-104 - "Deprec Summary 2010-12-16 FINAL.xls"

Big Rivers Electric Corporation
B&M Remaining Life Estimates

		Unit Remaining Life Spans					Account Remaining Life Spans		
		Reid	Coleman	Green	Wilson	HMP&L	311	312	314
1	2010 Minus Retirement Date	26	25	32	41	25			
2	Report, Table II-2, Longest-lifed Unit	31.3	26.0	33.2	35.1	26.2			
	Based on Typical Operating Hours								
3	Jan 2009 Data With NO Extension (400,000 hrs)	22	18	24	28	18	25.3	25.6	25.2
4	7.5 Year Extension Based on Jan 2009 Data, Initial ENG Results	31	25	32	35	25	32.6	32.8	32.5
5	7.5 Year Extension Based on Jan 2009 Data, Wilson Max Life	26	25	32	41	24	36.0	26.4	35.8
6	7.5 Year Extension Based on 2011 Data, Wilson Max Life	26	22	29	32	22	29.6	29.8	29.5
7	2011 Data With 5 Yr Extension	26	22	29	38	22	33.1	33.5	32.8
8	7.5 Year Extension Based on 2011 Data, Initial ENG Results	26	20	26	30	20	27.4	27.6	27.3
9	**Based on 5-year Average Operation Hours**								
10	Jan 2009 Data With NO Extension (400,000 hrs)	70	12	20	29	16	25.4	25.1	24.8
11	7.5 Year Extension Based on Jan 2009 Data, Initial ENG Results	86	19	27	36	23	32.6	32.2	32.0
12	7.5 Year Extension Based on Jan 2009 Data, Wilson Max Life	26	19	27	41	23	33.9	34.5	33.6
13	7.5 Year Extension Based on 2011 Data, Wilson Max Life	26	16	24	33	21	28.1	28.5	27.9
	2011 Data With 5 Yr Extension	26	16	24	38	21	31.0	31.6	30.7
14	7.5 Year Extension Based on 2011 Data, Initial ENG Results	26	14	22	31	18	26.1	26.5	25.9
15	Used in Interm Retirement Analysis						28.5	26.0	26.0
16	**Reported in Table ES-1**						**30**	**28**	**28**

Big Rivers Electric Corporations
Burns & McDonnell Life Span Estimates

Unit	Installation Date	Estimated Retirement Date	Average Service Life	Study Date	Estimated Remaining Unit Life
(1)	(2)	(3)	(4)	(5)	(6)
Coleman 1	1969	2035	66	2010	25
Coleman 2	1970	2035	65	2010	25
Colemen 3	1972	2035	63	2010	25
Green 1	1979	2042	63	2010	32
Green 2	1981	2042	61	2010	32
HMP&L 1	1973	2035	62	2010	25
HMP&L 2	1974	2035	61	2010	25
Reid 1	1966	2036	70	2010	26
Wilson 1	1986	2051	65	2010	41

Source:
(2) & (3) Response to Item KIUC 1-7
(4)=(3)-(3)
(6)=(3)-(5)

Big Rivers Electric Corporation
Development of Account Composite Remaining Life Spans

Account	Orignial Cost 4/30/2010	Remaining Life Span	Life Years
	(1)	(2)	(3)
311 - Structures			
Reid	3,181,843	26	82,727,917
Coleman	18,937,203	25	473,430,085
Green	26,723,028	32	855,136,902
Wilson	73,000,144	41	2,993,005,918
HMPL	421,179	25	10,529,475
Reid/HMPL Shared	553,336	26	14,386,739
Reid/Green/HMPL Shared	933,221	32	29,863,082
Central Machine Shop Green	693,610	32	22,195,513
	124,443,565	**36.01**	4,481,275,631
			-
312 - Boiler Plant			-
Central lab	29,686	59	1,741,602
Reid	7,218,409	26	187,678,638
Coleman	74,518,359	25	1,862,958,983
	161,734,476	32	5,175,503,237
Wilson	407,220,726	41	16,696,049,769
HMPL	16,483,318	25	412,082,957
Reid/HMPL Shared	2,504,162	26	65,108,206
Reid/Green/HMPL Shared	366,885	32	11,740,324
Barges	1,186,253	59	69,593,495
	671,262,275	**36.47**	24,482,457,211
312 -Boiler Plant - Env Compl			
Env - Central Lab	220,241	58	12,778,004
Env - Reid	5,046,851	26	131,218,129
Env - Coleman	121,851,087	25	3,046,277,173
Env - Green	114,693,688	32	3,670,198,026
Env - Wilson	262,004,068	41	10,742,166,803
Env - HMPL - SCR	35,338,718	25	883,467,949
Env - Reid/HMPL Shared	1,899,173	26	49,378,491
Env - Green/HMPL Shared	15,438	32	494,025
Env - HMPL - SCR	36,983,181	26	961,562,702
	578,052,445	**33.73**	19,497,541,301

Big Rivers Electric Corporation
Development of Account Composite Remaining Life Spans

Account	Orignial Cost 4/30/2010	Remaining Life Span	Life Years
314 - Turbine			
Reid	4,310,531	26	112,073,795
Coleman	32,415,575	25	810,389,371
Green	57,679,599	32	1,845,747,175
Wilson	126,942,316	41	5,204,634,936
HMPL	4,509,416	25	112,735,388
Reid/HMPL Shared	226,351	26	5,885,137
Reid/Green/HMPL Shared	18,495	32	591,845
	226,102,282	**35.79**	8,092,057,647
315 - Electric Equipment			
Reid	1,494,659	26	38,861,126
Coleman	7,557,766	25	188,944,154
Green	16,091,240	32	514,919,671
Wilson	35,017,398	41	1,435,713,333
HMPL	171,384	25	4,284,607
Central Machine Shop Green	43,548	32	1,393,538
	60,375,995	**36.18**	2,184,116,429
			-
316 - Misc. Equipment			-
Central lab	56,008	41	2,296,331
Reid	1,227	26	31,904
Coleman	755,850	25	18,896,241
Green	779,448	32	24,942,331
Wilson	666,432	41	27,323,714
HMPL	328,836	25	8,220,905
Reid/HMPL Shared	296,710	26	7,714,458
Reid/Green/HMPL Shared	38,962	32	1,246,782
Central Machine Shop Green	107,700	32	3,446,394
			-
	3,031,173	**30.29**	91,822,730
			-
Reid Combustion Turbine			-
340 Land	475,968		-
341 Structures	154,233	21.32	3,288,195
342 Fuel Holders & Access.	1,436,912	21.48	30,869,902
343 Prime Mover	4,915,886	21.30	104,728,841
344 Generators	1,102,964	21.50	23,713,719
345 Access Elec. Equipment	317,726	21.24	6,749,434
			-
	7,927,719	**21.36**	169,350,091

Big Rivers Electric Corporation
Interim Life Table

311 Structures & Improvements

Remaining Life Year	Surviving Plant	Interim Retirements @.00066	Life Years	Remaining Life
1	124,443,565	82,133	41,066	
2	124,361,432	82,079	123,118	
3	124,279,354	82,024	205,061	
4	124,197,329	81,970	286,896	
5	124,115,359	81,916	368,623	
6	124,033,443	81,862	450,241	
7	123,951,581	81,808	531,752	
8	123,869,773	81,754	613,155	
9	123,788,019	81,700	694,451	
10	123,706,319	81,646	775,639	
11	123,624,673	81,592	856,719	
12	123,543,080	81,538	937,692	
13	123,461,542	81,485	1,018,558	
14	123,380,057	81,431	1,099,316	
15	123,298,626	81,377	1,179,968	
16	123,217,249	81,323	1,260,512	
17	123,135,926	81,270	1,340,950	
18	123,054,656	81,216	1,421,281	
19	122,973,440	81,162	1,501,506	
20	122,892,278	81,109	1,581,624	
21	122,811,169	81,055	1,661,635	
22	122,730,113	81,002	1,741,540	
23	122,649,112	80,948	1,821,339	
24	122,568,163	80,895	1,901,032	
25	122,487,268	80,842	1,980,619	
26	122,406,427	80,788	2,060,100	
27	122,325,638	80,735	2,139,475	
28	122,244,903	80,682	2,218,745	
29	122,164,222	80,628	2,297,909	
30	122,083,593	80,575	2,376,968	
31	122,003,018	80,522	2,455,921	
32	121,922,496	80,469	2,534,769	
33	121,842,027	80,416	2,613,511	
34	121,761,612	80,363	2,692,149	
35	121,681,249	80,310	2,770,682	
36.01	121,600,939		4,378,911,242	
			4,428,465,766	35.59

Big Rivers Electric Corporation
Interim Life Table

312 Boiler Plant

Remaining Life Year	Surviving Plant	Interim Retirements @.00308	Life Years	Remaining Life
1	671,262,275	2,067,488	1,033,744	
2	669,194,787	2,061,120	3,091,680	
3	667,133,667	2,054,772	5,136,929	
4	665,078,896	2,048,443	7,169,550	
5	663,030,453	2,042,134	9,189,602	
6	660,988,319	2,035,844	11,197,142	
7	658,952,475	2,029,574	13,192,229	
8	656,922,901	2,023,323	15,174,919	
9	654,899,579	2,017,091	17,145,271	
10	652,882,488	2,010,878	19,103,342	
11	650,871,610	2,004,685	21,049,188	
12	648,866,925	1,998,510	22,982,866	
13	646,868,415	1,992,355	24,904,434	
14	644,876,060	1,986,218	26,813,947	
15	642,889,842	1,980,101	28,711,460	
16	640,909,741	1,974,002	30,597,031	
17	638,935,739	1,967,922	32,470,714	
18	636,967,817	1,961,861	34,332,565	
19	635,005,957	1,955,818	36,182,639	
20	633,050,138	1,949,794	38,020,991	
21	631,100,344	1,943,789	39,847,676	
22	629,156,555	1,937,802	41,662,747	
23	627,218,752	1,931,834	43,466,260	
24	625,286,919	1,925,884	45,258,267	
25	623,361,035	1,919,952	47,038,824	
26	621,441,083	1,914,039	48,807,983	
27	619,527,044	1,908,143	50,565,797	
28	617,618,901	1,902,266	52,312,321	
29	615,716,635	1,896,407	54,047,606	
30	613,820,228	1,890,566	55,771,706	
31	611,929,661	1,884,743	57,484,672	
32	610,044,918	1,878,938	59,186,558	
33	608,165,980	1,873,151	60,877,415	
34	606,292,829	1,867,382	62,557,294	
35	604,425,447	1,861,630	64,226,248	
36	602,563,816	773,909	27,473,765	
36.47	601,789,907		21,947,277,922	
			23,155,363,304	34.50

Big Rivers Electric Corporation
Interim Life Table

312 A-K Boiler Plant Equipment - Environmental

Remaining Life Year	Surviving Plant	Interim Retirements @.00158	Life Years	Remaining Life
1	578,052,445	913,323	456,661	
2	577,139,122	911,880	1,367,820	
3	576,227,242	910,439	2,276,098	
4	575,316,803	909,001	3,181,502	
5	574,407,803	907,564	4,084,039	
6	573,500,238	906,130	4,983,717	
7	572,594,108	904,699	5,880,541	
8	571,689,409	903,269	6,774,520	
9	570,786,140	901,842	7,665,658	
10	569,884,298	900,417	8,553,963	
11	568,983,881	898,995	9,439,443	
12	568,084,886	897,574	10,322,102	
13	567,187,312	896,156	11,201,949	
14	566,291,156	894,740	12,078,990	
15	565,396,416	893,326	12,953,232	
16	564,503,090	891,915	13,824,681	
17	563,611,175	890,506	14,693,343	
18	562,720,669	889,099	15,559,227	
19	561,831,571	887,694	16,422,337	
20	560,943,877	886,291	17,282,681	
21	560,057,585	884,891	18,140,265	
22	559,172,694	883,493	18,995,096	
23	558,289,202	882,097	19,847,181	
24	557,407,105	880,703	20,696,526	
25	556,526,401	879,312	21,543,137	
26	555,647,090	877,922	22,387,021	
27	554,769,167	876,535	23,228,185	
28	553,892,632	875,150	24,066,635	
29	553,017,482	873,768	24,902,377	
30	552,143,714	872,387	25,735,419	
31	551,271,327	871,009	26,565,765	
32	550,400,318	869,633	27,393,424	
33	549,530,686	334,280	10,864,084	
33.77	549,196,406		18,546,362,640	
			19,009,730,260	32.89

Big Rivers Electric Corporation
Interim Life Table

314 Turbines

Remaining Life Year	Surviving Plant	Interim Retirements @.00226	Life Years	Remaining Life
1	225,272,354	509,116	254,558	
2	224,763,238	507,965	761,947	
3	224,255,273	506,817	1,267,042	
4	223,748,457	505,672	1,769,850	
5	223,242,785	504,529	2,270,379	
6	222,738,256	503,388	2,768,637	
7	222,234,868	502,251	3,264,630	
8	221,732,617	501,116	3,758,368	
9	221,231,501	499,983	4,249,857	
10	220,731,518	498,853	4,739,106	
11	220,232,665	497,726	5,226,121	
12	219,734,939	496,601	5,710,911	
13	219,238,338	495,479	6,193,483	
14	218,742,860	494,359	6,673,845	
15	218,248,501	493,242	7,152,003	
16	217,755,259	492,127	7,627,967	
17	217,263,132	491,015	8,101,742	
18	216,772,117	489,905	8,573,337	
19	216,282,212	488,798	9,042,759	
20	215,793,415	487,693	9,510,016	
21	215,305,722	486,591	9,975,114	
22	214,819,131	485,491	10,438,062	
23	214,333,639	484,394	10,898,866	
24	213,849,245	483,299	11,357,533	
25	213,365,946	482,207	11,814,072	
26	212,883,739	481,117	12,268,490	
27	212,402,622	480,030	12,720,793	
28	211,922,592	478,945	13,170,989	
29	211,443,647	477,863	13,619,085	
30	210,965,784	476,783	14,065,089	
31	210,489,002	475,705	14,509,007	
32	210,013,296	474,630	14,950,847	
33	209,538,666	473,557	15,390,615	
34	209,065,109	472,487	15,828,319	
35	208,592,622	186,211	6,517,372	
35.79	208,406,411		7,458,733,615	
			7,745,174,427	34.38

Big Rivers Electric Corporation
Interim Life Table

315 Electric Equipment

Remaining Life Year	Surviving Plant	Interim Retirements @.00112	Life Years	Remaining Life
1	60,355,721	67,598	33,799	
2	60,288,122	67,523	101,284	
3	60,220,600	67,447	168,618	
4	60,153,152	67,372	235,800	
5	60,085,781	67,296	302,832	
6	60,018,485	67,221	369,714	
7	59,951,264	67,145	436,445	
8	59,884,119	67,070	503,027	
9	59,817,049	66,995	569,458	
10	59,750,053	66,920	635,741	
11	59,683,133	66,845	701,874	
12	59,616,288	66,770	767,858	
13	59,549,518	66,695	833,693	
14	59,482,823	66,621	899,380	
15	59,416,202	66,546	964,919	
16	59,349,656	66,472	1,030,310	
17	59,283,184	66,397	1,095,553	
18	59,216,787	66,323	1,160,649	
19	59,150,464	66,249	1,225,598	
20	59,084,216	66,174	1,290,399	
21	59,018,041	66,100	1,355,054	
22	58,951,941	66,026	1,419,563	
23	58,885,915	65,952	1,483,925	
24	58,819,963	65,878	1,548,141	
25	58,754,084	65,805	1,612,212	
26	58,688,280	65,731	1,676,137	
27	58,622,549	65,657	1,739,917	
28	58,556,892	65,584	1,803,552	
29	58,491,308	65,510	1,867,043	
30	58,425,798	65,437	1,930,388	
31	58,360,361	65,364	1,993,590	
32	58,294,997	65,290	2,056,647	
33	58,229,707	65,217	2,119,561	
34	58,164,489	65,144	2,182,332	
35	58,099,345	65,071	2,244,959	
36	58,034,274	5,850	210,595	
36.18	58,034,274		2,099,404,085	
			2,139,974,653	35.46

Big Rivers Electric Corporation
Development of KUIC Recommended Depreciation Rates

Account	Net Salvage Factor	Orignial Cost 4/30/2010	Accumulated Depreciation	Total To Be Accrued	Remaining Life	Annual Accrual	Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
311 - Structures	-4.50%	124,375,974	78,124,758	51,943,043	35.59	1,459,643	1.17%
312 - Boiler Plant	-5.03%	667,206,536	347,237,018	357,770,010	34.50	10,371,572	1.55%
312 -Boiler Plant - Env Compl	-1.96%	574,184,346	216,926,144	372,467,792	32.89	11,326,090	1.97%
312 Short-lived Boiler Plant	0.00%	4,077,693	376,213	3,701,480	4.70	787,549	19.31%
314 - Turbine	-8.17%	225,272,354	124,744,924	119,840,416	34.38	3,485,620	1.55%
315 - Electric Equipment	2.98%	60,355,721	35,350,377	23,223,801	35.46	655,003	1.09%
316 - Misc. Equipment	0.55%	3,014,912	42,128	2,972,518	26.00	114,328	3.79%
Reid Combustion Turbine							
340 Land		475,968	0				
341 Structures	0.0%	154,233	115,766	1,321,145	21.32	61,968	4.31%
342 Fuel Holders & Access.	-134.8%	1,436,912	564,590	552,884	21.48	25,735	5.41%
343 Prime Mover	-38.3%	4,915,886	3,637,977	3,161,718	21.30	148,408	3.02%
344 Generators	0.0%	1,102,964	984,479	118,484	21.50	5,511	0.50%
345 Access Elec. Equipment	0.0%	317,726	179,425	138,301	21.24	6,510	2.05%
		7,455,761	5,482,237	5,292,533		248,133	

Sources:
(1) Table ES-1
(2) Response to Item KIUC 1-4, "Active Property Records.xls" and AG 1-104 - "Deprec Summary 2010-12-16 FINAL.xls"
(3) Responose to Item KIUC 1-4, "Acct 1089 Accum Depr by RUS Account at 04-30-10.xls"
(4) ((2)-(3)) - ((1)x(2))
(5) Schedules 4-8
(6) (4)/(5)
(7) (6)/(1)

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Initial Request for Information dated April 1, 2011

April 15, 2011

Item 7) *Please identify the date of installation and the currently forecast year of retirement of each:*

a. Production unit and plant,

b. Transmission substation,

c. Structure in Account 290.

Provide all underlying documentation.

Response) a. The date of installation may not always align with the date in service. The date in service for each production unit was provided to Burns & McDonnell by Big Rivers. Discussion of each unit's year of retirement is provided in Part II of the Report on the Comprehensive Depreciation Study. The date in service and the estimated year of retirement for the production facilities are shown below:

	Date of Installation	Year of Retirement
COLEMAN 1	1969	2035
COLEMAN 2	1970	2035
COLEMAN 3	1972	2035
GREEN 1	1979	2042
GREEN 2	1981	2042
HMP&L - 1	1973	2035
HMP&L - 2	1974	2035
REID 1	1966	2036
WILSON 1	1986	2051

VERIFICATION

I verify, sate, and affirm that I prepared or supervised the preparation of my Supplemental Testimony filed with this verification, and that this Supplemental Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Charles W. King

DISTRICT OF COLUMBIA
WASHINGTON, DC

SUBSCRIBED AND SWORN TO before me by Charles W. King on this the 23rd day of May, 2011.

Donna A. Jeffries, Notary Public

DONNA ANN JEFFRIES
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires July 14, 2015

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

REDACTED

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	**)**	
ELECTRIC CORPORATION FOR	**)**	**CASE NO. 2011-00036**
A GENERAL ADJUSTMENT IN RATES	**)**	

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

Q. Please state your occupation and employer.

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, and a Certified Management Accountant ("CMA").

I have been an active participant in the utility industry for more than thirty years, as a consultant in the industry since 1983 and as an employee of The Toledo Edison Company from 1976 to 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on more than two hundred occasions, including proceedings before the Kentucky Public Service Commission ("Commission"). I have testified in several Big Rivers Electric Corporation ("BREC" or "Company") proceedings before the Commission. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service on the Big Rivers Electric Corporation system.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's revenue requirement, including specific adjustments, to summarize the revenue requirement effects of recommendations made by various KIUC witnesses, and to address the retirement of patronage capital to mitigate the effects of the rate increase.

Q. Please summarize your testimony.

A. I recommend that the Commission increase BREC's base rates by no more than $18.679 million, a reduction of at least $21.274 million compared to the Company's requested increase of $39.953 million. This reduction is comprised of numerous adjustments to the Company's revenue requirement as filed, which are summarized on the following table.

Summary of KIUC Adjustments to Big Rivers Revenue Requirement
$ Million

Big Rivers Requested Increase		39.953
KIUC Adjustments		
Increase Smelter Rates to Top of TIER Adjustment	(7.129)	
Exclude Avoided Interest on RUS Series A Note	(2.046)	
Exclude TIER on Avoided Interest on RUS Series A Note	(0.491)	
Exclude Current Interest on CWIP	(0.516)	
Exclude TIER on Current Interest on CWIP	(0.124)	
Exclude MISO Rate Case Amortization Expense	(0.534)	
Exclude Capitalized Labor and Labor Overheads	(1.034)	
Exclude 2012-2014 Inflation on Non-Labor Non-Outage Maintenance	(1.324)	
Exclude Non-Recurring MISO Expenses	(0.062)	
Exclude Depreciation Expense on Retirements	(1.045)	
Reduce Transmission Expense Consistent with BREC OSS Assumptions	(0.194)	
Eliminate DSM Expenses	(1.000)	
Adjust Depreciation Expense Based on KIUC Depreciation Rates	(5.776)	
Total KIUC Adjustments		(21.274)
Big Rivers Increase after KIUC Adjustments		18.679

I address the substance of all the adjustments on the preceding table except for those supported by KIUC witnesses Mr. Stephen Baron and Mr. Charles King.

I also quantify the effect on the revenue requirement of the depreciation rates recommended by Mr. King.

In addition to the revenue requirement adjustments, I recommend that the Commission direct the Company to adopt and implement a plan to retire (refund) patronage capital. The retirement of patronage capital is an important component of the KIUC proposal in this proceeding and provides an opportunity for the Commission to mitigate the effects of the rate increase on all ratepayers. I recommend that the Company adopt and implement a plan to annually retire patronage capital equivalent to 25% of the prior year's net margins, subject to various qualifications. This recommendation carefully balances the need to mitigate the effect of the rate increase on ratepayers, including the Smelters and their continued financial viability, with the need to maintain and enhance the Company's financial health. This recommendation also recognizes that Big Rivers must comply with the requirements of its lenders and limitations on the retirement of patronage capital set forth in various agreements.

Finally, this recommendation is consistent with the recommendations of the Capital Credits Task Force, a joint project of the National Rural Electric Cooperative Association ("NRECA") and the National Rural Utilities Cooperative Finance Corporation ("CFC"), with the assistance of the RUS. In its Report, the Capital Credits Task Force recommended that "Every electric cooperative should have a policy for annually allocating capital credits and, subject to the board of directors' discretion and the cooperative's financial condition, annually retiring capital credits."

I have structured the remainder of my testimony to follow the same sequence as this summary.

II. REVENUE REQUIREMENT ISSUES

Smelter TIER Adjustment Charges and Revenues Will Not be Reduced When Rates Are Reset on September 1, 2011 or on January 1, 2012

Q. Mr. Baron, Mr. Fayne and you all recommend that the Commission reject the Company's proposal that rates should be established based on the assumption that the Smelters will be charged the midpoint of the $1.95/mWh TIER Adjustment bandwidth. What effect does this recommendation have on the Company's proposed rate increase?

A. The Company's assumption that the Smelters will be charged the midpoint of the $1.95/mWh TIER Adjustment has the effect of reducing revenues by $7.129 million and in that manner, increasing the revenue requirement by the same amount. Thus, the elimination of the proforma adjustment restores the revenues to the amount the Company actually received during the test year and reduces the revenue requirement by the same $7.129 million.

Q. Is the Company's proforma reduction to the TIER Adjustment Charge revenues consistent with the TIER Adjustment Charge and revenues that are reflected in the Company's multi-year financial forecast provided in response to discovery in this proceeding?

A. No. The Company's proposed proforma adjustment to test year revenues assumes that it will reduce the TIER Adjustment Charge from the present $1.95 per mWh, the maximum under the present bandwidth, to $0.975 per mWh, or the midpoint of the present TIER Adjustment bandwidth and that this will reduce the Smelter revenues by $7.129 million. The Company's calculation of the proforma adjustment is reflected on Exhibit Wolfram-2 Reference Schedule 2.22.

However, there is no evidence that the Company actually will reduce the TIER Adjustment Charge; in fact, all the evidence is to the contrary. For each month of the test year and each month since the end of the test year to date, the Smelters actually paid the full $1.95 TIER Adjustment.

For each month in the Company's 2011 budget, as revised to reflect its request in this proceeding (response to KIUC 1-43), the Company assumed that the TIER Adjustment Charge will remain at [redacted] per mWh through the end of 2011 and that there will be no reduction in September 2011, the effective date of the rates set in this proceeding. In its 2012 through 2014 multi-year forecast, the Company assumed that the TIER Adjustment Charge will increase to the maximum [redacted] per mWh on January 1, 2012, the date when the maximum additional charge allowed under the Smelter contracts is increased. The Company provided its 2011 budget and its multi-year financial forecast, along with supporting schedules in the confidential responses to KIUC 1-43, 1-44 and 1-45.

These assumptions reflected in the Company's budget and multi-year forecast are relevant because they demonstrate that the proforma reduction in revenues from the Smelters is illusory; the Company itself assumes that there actually will be no reduction in the TIER Adjustment Charge on or after September 1, 2011. Instead, the Company actually will continue to recover the maximum TIER Adjustment Charge and revenue from the Smelters and this will increase by another $1.00 per mWh or $7.3 million annually on January 1, 2012. Big Rivers' assumption that the Smelters will pay only half of the $1.95/mWh TIER Adjustment Charge will result in a biased and inaccurate test year and should be rejected.

<u>Interest Expense and TIER Should be Reduced for Actual Prepayment on RUS Series A Note</u>

Q. Please describe the Company's calculation of the annualized interest expense and TIER included in the revenue requirement.

A. The Company calculated the annualized interest expense at the end of the test year and computed the TIER on that interest expense using the Contract TIER of 1.24. The Company's calculation of annualized interest expense is detailed on the Int_WP workpaper supporting Exhibit Wolfram-2 Reference Schedule 2.15 provided in response to KIUC 1-37. I have attached a copy of this workpaper as my Exhibit___(LK-2).

Q. Are there known and measurable changes to the Company's interest expense that the Company failed to reflect in its calculation of annualized interest expense?

A. Yes. On April 1, 2011, the Company paid off $35.000 million of the RUS Series A Note, which it confirmed in response to KIUC 2-37. The Company used the funds in the Transition Reserve for this purpose after seeking and obtaining a waiver from CoBank enabling the payment to proceed. The correspondence between the Company and CoBank was provided in response to KIUC 1-38. I have attached a copy of the Company's response to KIUC 2-37 as my Exhibit___(LK-3) and a copy of certain relevant pages from the Company's response to KIUC 1-38 as my Exhibit___(LK-4).

Q. Should this known and measurable reduction in interest expense be reflected in the Company's revenue requirement?

A. Yes. The effect of this reduction in interest expense should be reflected in its revenue requirement as a matter of principle and consistency, particularly given the Company's attempt to convert the historic test year to a projected test year on a selective basis rather than on a comprehensive basis. As to the principle and the conceptual foundation for reflecting post test year changes in the revenue requirement, this is a known and measurable change and there is no uncertainty. This change actually has occurred and the Company's interest expense actually is lower than the amount reflected in its filing.

As to consistency, the Company proposes numerous other post test year adjustments that selectively increase its revenue requirement, all of which it claims are known and measurable, but which are subject to various uncertainties. Among its proposed post test year adjustments are depreciation expense on construction work in progress ("CWIP"), increases in maintenance expenses through 2014, and increases in labor and labor overheads through 2011. If the Commission adopts the Company's proposed post test year adjustments, which are subject to various uncertainties, on the arguable basis that they are known and measurable, then the Commission also should adopt an adjustment to reflect the actual reduction in interest expense, which is certain, on the basis that it actually is known and measurable.

Q. What is the effect of this known and measurable reduction in interest expense on the revenue requirement?

A. The effect is to reduce the revenue requirement by $2.537 million, consisting of the $2.046 million reduction in interest expense ($35.000 million times 5.845%) plus the contract TIER of $0.491 million (using the contract TIER of 1.24). The Company confirmed the reduction in interest expense in response to KIUC 2-37.

Q. In its response to KIUC 2-37, the Company asserted that the reduction in interest expense should be offset by the loss in interest income on the Transition Reserve. Please respond.

A. That assertion is not correct. The interest income on the Transition Reserve was not included in the Company's calculation of the revenue requirement and is not included in the computation of the Contract TIER. This can be seen on Exhibit Wolfram-2 page 2 of 2 on lines 4 and 5 where the Company removes the interest income from the test year margins used to compute the revenue deficiency. Thus, there is no interest income on the Transition Reserve to remove from the revenue requirement, which is based on meeting the Contract TIER.

<u>Current Recovery of Interest on CWIP Is Not Appropriate</u>

Q. Please describe the Company's proposal to include interest on CWIP in the revenue requirement.

A. The Company proposes to currently recover interest on CWIP along with the related contract TIER and discontinue its current policy of capitalizing the interest expense on CWIP as Allowance for Funds Used During Construction ("AFUDC"). This proposal has the effect of increasing the revenue requirement by $0.640 million, consisting of $0.516 million in avoided AFUDC (normally a reduction to the interest expense because it is capitalized) and $0.124 million for the related contract TIER.

Q. Should the Commission adopt this proposal?

A. No. First, the current recovery of interest on construction results in intergenerational inequities. The interest incurred during the construction of an asset is a cost of the asset and should be included in the CWIP and in plant in service after the construction is completed. All costs of that asset should be recovered from the ratepayers who are provided service from those assets over the lives of those assets.

Second, the Company's proposal will pressure and degrade its future financial performance through lower net margins, at least to the extent the Company cannot concurrently recover the increases in interest expense between rate cases through increases in the TIER Adjustment Charge. This will occur because the Company no longer will be able to capitalize the interest expense on future construction as AFUDC. The interest expense that otherwise would have been capitalized instead will directly reduce the Company's margins. The effect of this degradation will be particularly severe if the Company commences construction on new generating facilities, major non-environmental capital additions on its existing generating facilities, or new or major upgrades of its existing transmission facilities.

Third, the Company's proposal unnecessarily harms ratepayers. It is not revenue neutral because the increase in recoverable interest expense also requires the addition of the related Contract TIER to determine the revenue requirement. Thus, the loss of each dollar of AFUDC results in an increase in the revenue requirement of $1.24.

<u>Retroactive Deferral and Prospective Amortization of MISO Rate Case Expenses Is Not Appropriate</u>

Q. Please describe the Company's proposal to defer the MISO rate case expenses and amortize the deferral amounts.

A. The Company proposes to defer $1.603 million that it incurred prior to and during the test year in conjunction with Case No. 2010-00043 and FERC Docket Nos.

ER11-15 and ER11-16. Of this amount, the Company incurred $0.298 million prior to the test year and $1.305 million during the test year, according to Exhibit Wolfram-2 Reference Schedule 2.21. The Company included $0.534 million in amortization expense in its revenue requirement based on a 3 year amortization of the $1.603 million incurred.

Q. Did the Company defer these amounts prior to or during the test year?

A. No. The Company expensed these amounts. The Company now seeks to retroactively defer the amounts that it already expensed and then to prospectively amortize the deferred amount over three years commencing when rates are reset on or about September 1, 2011.

Q. Should the Commission authorize the proposed retroactive deferral and prospective amortization expense?

A. No. First, a portion of the expense was incurred prior to the test year and the Company's request, at least for this portion of the expense, constitutes improper retroactive ratemaking. Second, the expense incurred during the test year is non-recurring and simply should be removed from the test year, as the Company has proposed for other non-recurring expense amounts, and not deferred and amortized. Third, the proposed deferral and amortization is discretionary at best and will create an unnecessary and completely avoidable expense for the next three rate-effective years. Fourth, the Company's proposal could result in overrecovery of this completely avoidable expense. To the extent that rates are not reset precisely at the end of the three year amortization period in order to eliminate recovery of the discretionary expense, the Company will continue to recover as if the expense were continuing even though there no longer will be any expense to recover.

<u>Labor and Labor Overheads Should Be Reduced To Exclude Amounts That Will Be Capitalized</u>

Q. Are all the Company's labor and labor overhead costs actually expensed?

A. No. A portion of the Company's labor and labor overhead costs is expensed and a portion is capitalized and included in CWIP. In the test year, the Company capitalized and included in CWIP 1.505% of its labor and labor overhead costs, according to its response to KIUC 2-32(c). I have attached a copy of the Company's response to KIUC 2-32 as my Exhibit__(LK-5).

Q. Did the Company properly reduce its proforma labor and labor overheads costs for the portion that will be capitalized to CWIP?

A. No. The Company stated in response to KIUC 2-32(c) that: "None of the $68,708,897 pro forma labor and labor overheads were assumed to be capitalized."

Q. Should the Company's proposed labor and labor overhead costs be reduced by the amount that will be capitalized to CWIP?

A. Yes. The Company's failure to do so is an error in its filing that should be corrected to avoid double recovery through rates today and then again through rates over the life of the Company's CWIP assets once they are placed in-service. The Company actually capitalized 1.505% of its labor and labor overhead costs in the test year and the proforma costs should be reduced accordingly. The amounts that are capitalized are not a current expense and, unlike an expense, do not reduce the Company's margin. The Company's recovery of capitalized amounts will occur in the future through recovery of depreciation expense and interest and the related contract TIER on the amounts capitalized and financed.

Q. Have you quantified the adjustment to reduce the Company's proposed labor and labor overhead costs for the amount that will be capitalized.

A. Yes. The effect is a reduction in expense and the revenue requirement of $1.034 million ($68.709 million proforma labor and labor overheads cost times 1.505% capitalization percentage).

<u>Inflation Growth in Non-Labor and Non-Outage Maintenance Expense Projected For 2012 through 2014 Is Inappropriate</u>

Q. Please describe the calculations underlying the Company's proposed post-test year proforma adjustment to increase non-labor and non-outage maintenance expense.

A. The Company projected maintenance expenses for the years 2011 through 2014 and calculated the proforma expense based on the average expense projected for this 4 year period. The Company's calculations in support of its request are detailed on Exhibit Berry-3. The amounts on Exhibit Berry-3 were revised slightly in response to KIUC 2-34; however, I used the amounts included in the Company's revenue requirement as filed because I used the Company's request as the starting point for my analysis.

The Company's calculations include inflation growth on the test year maintenance expense in each year 2011 through 2014. The Company then added the incremental expense associated with specific projects for each year 2011 through 2014. Finally, the Company calculated the 4 year average of the expense calculated in this manner for 2011 through 2014.

Q. How much of the Company's proposed proforma adjustment is due to the projected inflation growth in the years 2011 through 2014?

A. The inflation-related expense is $2.155 million for the years 2011 through 2014, or 38%, of the $5.661 million proforma adjustment included in the Company's request as filed. The inflation-related expense included in the Company's proforma adjustment is $0.830 million in 2011 alone. The inflation-related expense included in the Company's proforma adjustment for the years 2012 through 2014 is $1.324 million.

Q. What is your recommendation?

A. I recommend that the Commission reduce the Company's proforma adjustment by $1.324 million to remove the projected inflation growth for the years 2012 through 2014. The Company's proposal to include inflation growth for 4 years beyond the test year violates any reasonable determination of the test year expense. At most, such an adjustment should be limited to the year immediately following the test year, assuming that all other relevant post test year adjustments also are made. The Company's proposal to include specific incremental maintenance expense in addition to the test year expense in and of itself provides a significant and reasonable increase in the maintenance expense without the need to resort to multi-year inflation growth extrapolations. In addition, the Company's estimate of inflation during 2012-2014 is not known and measurable; rather, it is arbitrary and the resulting proforma increase in expense appears to have been included for the sole purpose of increasing the revenue requirement.

Q. If the Commission does adopt the Company's proposed inflation-related expense for the years 2012 through 2014, then should it incorporate other proforma adjustments that in fact are known and measurable?

A. Yes. If the Commission adopts the Company's proposed inflation-related expense for the years 2012 through 2014, then it also should reflect the additional revenues the Company will recover due to the increase in the TIER Adjustment Charge from $1.95 to $2.95 on January 1, 2012. Such a proforma adjustment to revenues is known and measurable and would reduce the Company's revenue requirement by $7.312 million.

<u>Non-Recurring MISO Expenses Should Be Removed</u>

Q. Since its filing, has the Company identified additional non-recurring MISO expenses that should be removed from the revenue requirement?

A. Yes. The Company identified another $0.062 million in non-recurring MISO expenses that it should have removed from the revenue requirement, according to its response to KIUC 2-39. I have attached a copy of the Company's response to KIUC 2-39 as my Exhibit___(LK-6).

Q. Have you reflected this reduction in expense in your recommendations?

A. Yes. I have reflected this reduction on the table in the Summary section of my testimony.

<u>Depreciation Expense on Retirements Is Inappropriate</u>

Q. Please describe the Company's proposal to include depreciation expense on CWIP as of the end of the test year.

A. The Company's depreciation expense includes $2.313 million in proforma depreciation expense on $46.802 million in CWIP at the end of the test year. The Company's calculations are detailed on the Depr WP1 workpaper in the excel workbook provided in response to KIUC 1-37. The Company considers the CWIP as a "known and measurable" post test year adjustment to increase plant in service for capital additions through August 2011 and also considers the depreciation expense on the CWIP as a post test year adjustment, according to its response to KIUC 2-30. I have attached a copy of the narrative portion of the Company's response to KIUC 2-30 as my Exhibit___(LK-7).

Q. Does the Company also propose a proforma adjustment to reflect the reduction in depreciation expense due to post test year retirements from plant in service?

A. No. The Company failed to include such a proforma reduction in depreciation expense and the failure to include the post test year retirements along with the post test year additions violated the fundamental ratemaking principle of matching. The Company's proforma adjustment to increase depreciation expense is selective and one-sided; it includes only the depreciation expense on projected post test year additions to plant in service, but does not include the matching and offsetting reduction in depreciation expense on projected post test year retirements from plant in service. The Company argues that the projected additions are known and measurable, but that the projected retirements are not, according to its response to KIUC 2-30(h).

Q. Do you agree with the Company's rationale that the projected retirements are not known and measurable and should not be used in the calculation of proforma adjustment to reflect post test year depreciation expense?

A. No. The Company's rationale is inconsistent and inequitable. If the Commission adopts a post test year adjustment to depreciation expense, then it should reflect post test year changes in plant in service for both projected plant additions and projected retirements. If the Commission adopts a post test year adjustment to depreciation expense only for plant additions, then the adjustment necessarily overstates depreciation expense and overstates the revenue requirement.

Q. Have you quantified the effect on depreciation expense of the post test year retirements?

A. Yes. The effect is to reduce depreciation expense and the revenue requirement by $1.045 million. The Company's test year actual retirements constitute 45.15% of test year plant additions, according to the information provided by the Company in response to KIUC 2-31. I reduced the Company's proposed proforma depreciation expense on the projected plant additions by the test year percentage of retirements to plant additions. I have attached the relevant pages from the Company's response to KIUC 2-31 as my Exhibit___(LK-8) and provided my calculations of the reduction in depreciation expense on my Exhibit___(LK-9).

<u>Transmission of Electricity by Others Expense Should Be Reduced to Reflect Post Test Year Expense Reductions</u>

Q. Has the Company reduced the transmission of electricity by others expense since the test year?

A. Yes. The Company's 2011 budget and multi-year forecast through 2014 reflect $2.718 million for this expense, according to the Trial Bal workpaper in the excel workbook provided by the Company in response to KIUC 1-43 and its response to KIUC 2-28. This is $0.194 million less than the test year amount after adjustments to exclude the expenses paid to E.ON and Kentucky Utilities that are offset by equivalent revenue amounts, according to the response to KIUC 2-28. I have attached a copy of the relevant page from the Company's response to KIUC 1-43 as my Exhibit___(LK-10) and the Company's response to KIUC 2-28 as my Exhibit___(LK-11).

Q. Should the Commission adopt a post test year proforma adjustment to reflect the reduction in transmission of electricity by others expense?

A. Yes. The Company has proposed numerous post test year proforma adjustments, most of which increase the revenue requirement. The Commission should ensure that it also considers post test year adjustments that reduce the revenue requirement.

<u>DSM Expenses Should Be Eliminated</u>

Q. Mr. Baron recommends that the Commission reject the Company's proposed proforma adjustment to incur and recover $1.000 million in DSM expenses. Have you reflected this recommendation in your summary?

A. Yes. I reflected this recommendation in the table summarizing the KIUC recommendations in the Summary section of my testimony.

<u>Depreciation Expense Should Be Modified to Reflect KIUC Recommendations</u>

Q. Mr. King recommends that the Commission adopt depreciation rates that are different than those proposed by the Company. Have you quantified the effect of Mr. King's recommendations?

A. Yes. The effect is to reduce depreciation expense and the revenue requirement by $5.776 million. I calculated the proforma depreciation expense using the depreciation rates recommended by Mr. King applied to the Company's proposed plant in service, including the post test year plant additions from CWIP proposed by the Company, and reduced for the post test year plant retirements that I recommend. I then subtracted the proforma depreciation expense proposed by the Company, adjusted for the post test year plant retirements that I separately quantified. The calculations are shown on my Exhibit___(LK-12).

III. PATRONAGE CAPITAL

Q. What is patronage capital?

A. Patronage capital is the equity ownership or investment of the cooperative's members in the cooperative, according to the Capital Credits Task Force Report ("CCTFR").[1] The Company's patrons, or members, are Kenergy, Meade County, and Jackson Purchase. Generally, margins are credited to the patrons of a cooperative based on their relative purchases from the cooperative, according to

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[1] The Capital Credit Task Force Report was prepared jointly by NRECA and CFC. The CCTF Report was issued in January 2005.

the CCTFR. I have attached a copy of the entire CCTFR as my Exhibit___(LK-13).

In general, cooperatives must operate at cost with respect to their tax exempt purposes. That means that any excess of operating revenues collected over operating expenses from the provision of electricity must be allocated to patrons as capital credits, based on their participation, and ultimately returned to patrons, according to the CCTFR.

Q. What is the Company's patronage capital or members' equity at the end of the test year?

A. The Company had a very healthy $385.705 million in members' equity at October 31, 2010, according to its RUS Form 12 report provided in Exhibit 37 in the Company's filing. The Company also provided the amount of patronage capital in various formats for each of the member cooperatives and for each of the member's large customers, including each of the Smelters, in response to KIUC 2-24, 2-25 and 2-26. I have attached a copy of each of these responses as my Exhibit___(LK-14), Exhibit___(LK-15) and Exhibit___(LK-16), respectively.

Q. What is the Company's members' equity as a percentage of total capitalization and how does this compare to other generation and transmission cooperatives?

A. The Company's members' equity ratio was 32.11%, based on the members' equity and total capitalization provided in Exhibit 28 in the Company's filing.

The Company's members' equity ratio compares very favorably with other generation and transmission cooperatives that also are investment rated. In Case No. 2010-00067, East Kentucky Power Cooperative witness Mr. Daniel Walker sponsored two exhibits in which he compared the members' equity ratio of generation and transmission cooperatives that were investment rated and all generation and transmission cooperatives.

The average equity ratio for generation and transmission cooperatives that were investment rated was 17.6%, according to Mr. Walker's Exhibit DMW-2 in that proceeding. The average equity ratio for all generation and transmission cooperatives that were members of CFC was 15.21%, according to Mr. Walker's Exhibit DMW-3 in that proceeding. I have attached a copy of Mr. Walker's testimony and exhibits in Case No. 2010-00067 as my Exhibit___(LK-17).

Q. Is a 32.11% equity ratio consistent with an investment grade credit rating from Moody's?

A. Yes, an equity ratio of between 20% and 35% is consistent with an A investment grade credit rating for a generation and transmission cooperative. The Company's 32.11% equity ratio is near the top of that range, providing strong support for an investment grade credit rating.

Q. Does the Company presently have a plan for the retirement of patronage capital?

A. No. In response to KIUC 1-49, which asked for a copy of the Company's most recent capital rotation or capital credits distribution implementation plan, the Company stated the following:

> **Big Rivers has only had a positive equity position since the closing of the Unwind Transaction, which occurred less than 24 months ago. Big Rivers has not yet developed a more detailed implementation plan for the retirement or distribution of patronage capital other than what is provided in Article VIII, Section 5 of the current bylaws.**

The cited section of the Company's Bylaws is entitled "Retirement of Patronage Capital" and generally provides that the Board of Directors may retire patronage capital if the financial condition of the cooperative will not be impaired. The relevant language is as follows:

> **If, at any time prior to the liquidation of the cooperative, the board of directors shall determine that the financial condition of the cooperative will not be impaired thereby, the patrons' capital accounts may be retired in full or in part (except that no distribution shall be made that would result in a violation of any financial covenant of the cooperative). Generally, such retirements of capital shall be made in order of priority according to the year in which the patronage net earnings were allocated. Notwithstanding the foregoing, however, the board of directors shall have the discretion to determine the method of allocation, basis and order of priority of repayment for all amounts furnished as patronage capital.**

Q. Should the Company have a plan for the retirement of patronage capital?

A. Yes. One of the recommendations in the CCTFR is that every electric cooperative should have a Board-approved policy for annually allocating capital credits, and subject to the Board's discretion and the cooperative's financial condition, annually retiring capital credits.

Q. What factors should the Commission and the Company's Board of Directors consider in the development of a plan to retire patronage capital?

A. The CCTFR cites six factors to consider: 1) the cooperative's financial performance, 2) its equity management plan, 3) rate competitiveness, 4) regulatory bodies, 5) lender requirements, and 6) financial markets. Each of these factors is described in greater detail on pages 36-38 of the CCTFR.

Q. Is rate mitigation a factor in rate competitiveness?

A. Yes. The retirement of patronage capital can mitigate the effects of rate increases that are necessary to meet loan contract or covenants requirements, but that are in excess of the cooperative's expenses. The patronage capital belongs to the patrons. The CCTFR describes the retirement of patronage capital for this purpose as follows: "The cash members receive from capital credits retirements may effectively offset part of costs paid through rates. Depending on the retirement method adopted, this can have an immediate impact."

Q. Should the Commission direct the Company to adopt a plan to retire patronage capital to mitigate the effect of rate increases?

A. Yes. The mitigation of the effects of rate increases is an appropriate and relevant factor in such a plan, particularly given the magnitude of the Company's proposed increases on all customers, including the Smelters. Rate mitigation through the retirement of patronage capital will make the Smelters more competitive and thus help to maintain the critical economic benefits that they provide to the economy of Western Kentucky.

The CCFTR confirms the rate mitigation benefit through the retirement of patronage capital noting the advantage of the "reduced net cost of electricity for members" and noting further that "capital credit retirements offset a portion of the costs consumers pay through electric rates."

The important point is that the patronage capital belongs to the members and revenues collected in excess of the Company's costs in prior years can be used to mitigate the ongoing effects of present rates. Under a plan to retire patronage capital, this approach can be sustained year after year, where rates initially are set at levels in excess of costs sufficient for the Company to meet its Margins for Interest Ratio ("MFIR"), Contract TIER, Debt Service Coverage Ratio ("DSCR") and all other relevant ratios through the income statement, but then the excess amounts collected from ratepayers are returned to ratepayers on a rotation basis through the balance sheet (with no impairment of the various ratios that are measured using the income statement margins and expenses).

Q. Are there financial and other factors that should be considered in a plan to retire patronage capital?

A. Yes. The Commission and the Company should consider the Company's financial metrics, particularly as they impact the Company's liquidity and its debt ratings. In addition, the Commission and the Company should consider the RUS and CFC loan covenant and contract limitations.

Q. Will your proposal to retire patronage capital have a significant effect on the Company's financial metrics?

A. No. The proposal that I subsequently describe will result in the annual retirement of less than $3 million in patronage capital, or approximately 25% of the Company's annual margins. That means that there will be no deterioration of the Company's equity ratio from the present 32.11% due to the retention of 75% of the annual margins, all else equal.

In addition, the Company's equity ratio of 32.11% is substantially greater than required to maintain its investment grade credit rating according to the Company's own assessment. The Company itself has determined that it can "ensure its ability to maintain the targeted investment grade credit rating and ensure access to low-cost sources of capital" by maintaining a minimum equity ratio of 20%, according to its Financial Policy 104, which it claims "incorporates the key elements of an equity management plan." The Company provided this Financial Policy in response to Staff 1-2, which sought a copy of the Company's equity management plan.

The significance of the Financial Policy is that the Company believes it needs only a 20% equity ratio to maintain its investment grade credit rating. I have attached a copy of the Company's response to Staff 1-2 as my Exhibit___(LK-18).

Q. What are the restrictions on the retirement of patronage capital that are set

forth in the Company's loan agreements?

A. In response to KIUC 2-58, the Company identified the restrictions set forth in the Indenture dated July 1, 2009 and in the Amended and Consolidated Loan Contract dated July 16, 2009 between the Company and the United States of America. I have attached a copy of the Company's response to KIUC 1-58 as my Exhibit___(LK-19).

Under the Indenture, the Company may not make a distribution if it results in the equity ratio (defined in this case as equity divided by capitalization) being less than 20% as of the most recent quarter, or the Company may not make a distribution if it results in cumulative distributions made since the equity ratio first exceeded 20% exceeding the cumulative margins since that time. Regardless of these two limitations, the Company may make a distribution to the extent the resulting equity ratio is 30% or greater.

Under the Loan Contract, the Company may not make a distribution without prior written approval of the RUS if it violates the two limitations set forth in Section 5.24, entitled "Limitations on Distributions," of the Loan Contract, which states the following:

> **Without the prior written approval of RUS, the Borrower shall not in any calendar year make any Distributions to its members or stockholders except as follows:**
>
> ***(a) Equity above 30%.*** **If, after giving effect to any such Distribution, the Equity of the Borrower shall be greater than or equal to 30% of its Total Assets; or**
>
> ***(b) Equity above 25%.*** **If, after giving effect to any such Distribution, the aggregate of all Distributions made during the calendar year**

when added to such Distribution shall be less than or equal to 25% of the margins for the year to which the Distribution relates.

The Company claims that the limitations in the Loan Contract are more restrictive than those in the Indenture. The Company claims that the restriction under (a) above prohibits any retirement of patronage capital without written authorization from the RUS and without consideration of the restriction under (b) above, according to its response to KIUC 1-58.

Q. Do you agree that Section 5.24(a) of the Loan Contract prohibits any retirement of patronage capital without written authorization from the RUS?

A. No. First, the "or" between Section 5.24(a) and (b) means that the Company may make a distribution without written approval from the RUS if the Company does not violate either one or both of the (a) and (b) provisions. The Company must violate both limitations to trigger the requirement for written approval from the RUS.

Second, the Company apparently did not hold this interpretation of Section 2.54 of the Loan Contract in the manner described in its response to KIUC 1-58 until this rate proceeding. In its Prospectus for the $83.3 million County of Ohio, Kentucky Pollution Control Refunding Revenue Bonds, Series 2010A dated May 27, 2010, under the heading "Limitation on Distributions to Members," the Company did not mention any limitations on distributions to members arising from the Loan Contract. The Company cited only the provisions of the "Mortgage Indenture" and claimed that "[a]s of December 31, 2009, our equity to total capitalization ratio was 31% and we could have distributed approximately $21.8 million to our Members under the criteria described above." The description of the limitations on distributions is on page x of the Prospectus, which the Company provided as Exhibit 35 in its filing in this proceeding.

Q. Does the Company meet the requirements of Section 5.24(b) if its equity ratio, defined as equity divided by total assets, is more than 25% and it retires no more than 25% of the margins for the prior year?

A. Yes.

Q. How much could the Company distribute as of December 31, 2010?

A. The Company could distribute as much as $18.529 million. I calculated this amount by subtracting 25% of the $1,472.185 million total capitalization from the $386.575 million in equity at December 31, 2010 shown in the Company's response to KIUC 1-58.

Q. What is your recommendation?

A. I recommend that the Commission direct the Company to adopt and implement a plan for the annual retirement of patronage capital as a means of mitigating the ongoing effects of the rate increase on all ratepayers (rural, industrial, and Smelters) in this and future proceedings. The Company should distribute 25% of the prior year's margins each year to the extent the margins are available for distribution, subject to retaining its investment grade debt rating and meeting all

Indenture and Loan Contract limitations. The Commission should use all reasonable means to keep the Smelters' effective cost of power as low as possible in order to avoid the enormous risk to other ratepayers and creditors that would result from the total or partial shutdown of one or more of the Smelters and the transformation of Big Rivers into a merchant generator. Reducing the effective cost of power to the Smelters will help to sustain their viability and the 4,700 jobs, $176 million in annual payroll and the nearly $12.2 million in state and local taxes they provide.

The Commission also should ensure that the plan adopted and implemented retires patronage capital on an equitable basis to all ratepayers: rural, industrial and Smelters. Not only is this important for all ratepayers, it is an important economic development tool for the Commission to minimize the effect of rate increases on industrial ratepayers and to ensure the continued financial viability of the Smelters. The Company has discretion as to the methodology it employs to retire patronage capital. The Commission should ensure that it does not unduly benefit the rural ratepayers to the detriment of the industrials and Smelters.

This recommendation carefully balances the need to mitigate the effect of the rate increase on ratepayers, including the Smelters and their continued financial viability, with the need to maintain and enhance the Company's financial health. This recommendation is also carefully crafted to ensure that the retirement of patronage capital does not cause Big Rivers to violate RUS and CFC loan covenants and contract provisions.

In addition, my recommendation is consistent with that of the Capital Credits Task Force, which recommended that "Every electric cooperative should have a policy for annually allocating capital credits and, subject to the board of directors' discretion and the cooperative's financial condition, annually retiring capital credits."

Finally, my recommendation is consistent with the annual retirement of patronage capital by other cooperatives. For example, NRECA annually retires 50% of the margins from the prior year, according to correspondence from NRECA included in the Company's response to KIUC 1-38. I have attached a copy of the relevant pages from the Company's response to KIUC 1-38 as my Exhibit___(LK-20).

Q. For illustrative purposes, how much would the distribution be if the Company's margins in the prior year equaled the Contract TIER margin that you recommend in this proceeding?

A. The distribution could be as much as $2.708 million based on 25% of the $10.831 million for the Contract TIER margin that I recommend in this proceeding. I computed the amount of the Contract TIER margin that I recommend as the $11.446 million amount requested by the Company (Exhibit Wolfram 2 page 2 of 2) less the Contract TIER of $0.491 million due to the interest reduction on the RUS Series A Notes and less the Contract TIER of $0.124 million on the interest on CWIP recommendations that I discussed previously.

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT___(LK-1)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than thirty years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of May 2011

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.

Expert Testimony Appearances
of
Lane Kollen
As of May 2011

Date	Case	Jurisdict.	Party	Utility	Subject
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92

Expert Testimony Appearances
of
Lane Kollen
As of May 2011

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.

Expert Testimony Appearances
of
Lane Kollen
As of May 2011

Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements , detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.

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4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
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.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.

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5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

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12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.

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9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery mechanisms.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co. and Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.

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07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.

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01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp/	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/01	U-21453, U-20925, U-22092 Subdocket B Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense
04/02	U-25687 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092		Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless

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	(Subdocket C)		Staff		conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459, PUC Docket	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues, ITC, ADIT, excess earnings.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
05/04	29206 04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4556 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	Docket No. U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	Docket No. U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, etal.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and § 199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co Louisville Gas and Electric Co.	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06 05/06	31994 31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change. Retrospective ADFIT, prospective ADFIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
3/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPioint Energy Houston Electric	Proposed Regulations affecting flow-through to ratepayers of excess deferred income taxes and investment Tax credits on generation plant that Is sold or deregulated.
4/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated programs costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925 U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co..	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental And Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuctionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue Requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
04/08	2007-00562 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Supplemental Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, incl costs recovered in existing rates, TIER
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, incl projected test year rate base and expenses.
07/08	27163 Panel with Victoria Taylor	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO 08-918-EL-SSO	OH OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-564 2007-565 2008-251 2008-252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09	U-21453,U-20925 U-22092 (Subdocket J)		Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	U-21453, U-20925 U-22092 (Subdocket J) Rebuttal		Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925 U-22092 (Subdocket J) Supplemental Rebuttal		Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue Requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00458 2009-00459	KY	Kentucky Industrial	Kentucky Utilities Company Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation, FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.

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Date	Case	Jurisdict.	Party	Utility	Subject
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, the Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, including resolution of S02 allowance expense, variable O&M expense, and tiered sharing of off-system sales margins.
04/11 05/11	38306 Direct Supplemental Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company and Wheeling Power Company	Deferral recovery phase-in, construction surcharge

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-2)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

Historical Interest Expense - November 2009 to October 2010

	YTD-December 2009	YTD-October 2009	Actual Interest Expense November - December 2009	YTD October 2010	Total Interest Expense November 2009 - October 2010
RUS Note - Series A	$ 43,830,833.92	$ 37,327,612.71	$ 6,503,221.21	$ 30,949,411.62	$ 37,452,632.83
DS/L Adjustment	(4,089,399.98)	(3,405,966.01)	(683,433.97)	(3,405,966.01)	(4,089,399.98)
RUS Note - Series B	6,136,352.28	5,088,902.19	1,047,450.09	5,389,228.45	6,436,678.54
RUS Arbitrage Interest	213,490.04	213,490.04	-	-	-
P.C. Bonds - Bond Int-1983 Series	1,563,841.77	1,247,865.54	315,976.23	1,599,951.67	1,915,927.90
P.C. Bonds - Bond Int-2001A/2010A Series	8,744,567.90	8,147,202.77	597,365.13	3,222,923.27	3,820,288.40
P.C. Bonds-Remarking/Broker Fees	269,942.34	224,828.69	45,113.65	132,685.65	177,799.30
Dexia Credit Local - Commitment Fee	48,916.10	48,532.57	383.53	1,206.46	1,589.99
AMBAC	2,060,613.53	1,401,408.71	659,204.82	1,247,987.52	1,907,192.34
LEM Settlement Note	675,850.54	675,850.54	-	-	-
Defeased S/L Int	-	-	-	-	-
PMCC Promissory Note-DS/L	572,918.91	572,918.91	-	-	-
Total	$ 60,027,927.35	$ 51,542,646.66	$ 8,485,280.69	$ 39,137,428.63	$ 47,622,709.32

Proforma Year - November 2010 to October 2011

RUS Note - Series A	$ 37,692,851.83
DS/L Adjustment	(4,089,399.98)
RUS Note - Series B	6,818,112.92
RUS Arbitrage Interest	-
P.C. Bonds - Bond Int-1983 Series	1,937,541.64
P.C. Bonds - Bond Int-2001A/2010A Series	5,067,416.64
P.C. Bonds-Remarking/Broker Fees	58,799.99
Dexia Credit Local - Commitment Fee	-
AMBAC	207,794.49
LEM Settlement Note	-
Defeased S/L Int	-
PMCC Promissory Note-DS/L	-
Total	$ 47,693,117.53

	Proforma	Historical	Proforma Adjustment	
RUS Note - Series A	$ 37,692,851.83	$ 37,452,632.83	$ 240,219.00	Proforma amount is based on scheduled payments without additional prepayments
DS/L Adjustment	(4,089,399.98)	(4,089,399.98)	-	
RUS Note - Series B	6,818,112.92	6,436,678.54	381,434.38	Interest is capitalized quarterly into principal
RUS Arbitrage Interest	-	-	-	
P.C. Bonds - Bond Int-1983 Series	1,937,541.64	1,915,927.90	21,613.74	
P.C. Bonds - Bond Int-2001A/2010A Series	5,067,416.64	3,820,288.40	1,247,128.24	P.C. Bonds were reissued at higher rate in June 2010
P.C. Bonds-Remarking/Broker Fees	58,799.99	177,799.30	(118,999.31)	Broker Fees were eliminated with reissue of 2010 P.C. Bonds
Dexia Credit Local - Commitment Fee	-	1,589.99	(1,589.99)	Dexia purchased all shares from the market in November 2009
AMBAC	207,794.49	1,907,192.34	(1,699,397.85)	Amortization for 2001A P.C. Bonds were complete in 2010
LEM Settlement Note	-	-	-	
Defeased S/L Int	-	-	-	
PMCC Promissory Note-DS/L	-	-	-	
Total	$ 47,693,117.53	$ 47,622,709.32	$ 70,408.21	

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT___(LK-3)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 37) *Refer to the Debt tab in the Company's excel workbook provided in response to KIUC 1-43, which provide the multi-year financial forecast model.*

a. Please confirm that the April 2011 entries under RUS [Debt] GAAP reflects the Company's use of the transition reserve to prepay the RUS Series A Note and that this transaction actually occurred.
b. Please provide the accounting journal entries and the date at which the transaction occurred.
c. Please confirm that this transaction reduced the Company's interest expense and provide a quantification of the reduction in interest expense on an annualized basis.
d. Please confirm that this reduction in interest expense was not reflected in the proforma interest expense shown on Exhibit Wolfram-2 Reference Schedule 2.15.
e. Please provide a copy of the RUS written authorization to use the transition reserve in this manner.

Response)

a. Yes. The April 2011 entries under RUS [Debt] GAAP reflect Big Rivers' use of the Transition Reserve to prepay the RUS Series A Note on April 1, 2011.
b. The Transition Reserve funds were wired into Big Rivers' general fund account on March 31, 2011, were invested over night, then applied to the RUS Series A Note on April 1, 2011. The journal entries to account for the transaction were as follows:

<u>Cash Receipts Journal Entry (March 31, 2011)</u>

13110000 Cash-General	$35,451,994.51
12840001 Other Special Funds-Trans Res	
	$35,451,994.51

<u>Wire Request (April 1, 2011)</u>

23715000 Accrued Interest-RUS Series A Note	$7,992,497.92
22435000 RUS Series A Note	$27,459,496.59
13110000 Cash-General	$35,451,994.51

c. Yes. On an annualized basis this transaction will reduce interest expense on long-term debt approximately $2,045,750.00 ($35,000,000.00 X 5.845%). Big Rivers will lose interest income of approximately $262,500.00 ($35,000,000.00 X .75%) as a result of these funds not residing in the Transition Reserve. The net benefit to Big Rivers and its members is approximately $1,783,250.00 ($2,045,750.00 - $262,500.00). In calculating the annualized benefit of this transaction, $35 million is used rather than $35,451,994.51 because Big Rivers must maintain $35 million prepaid in accordance with an agreement with CoBank whose approval was needed because the transition reserve was included in the line of credit agreement, and plans to "claw back" $451,994.51 at the next RUS Series A Note quarterly payment date.

d. Yes. The net benefit resulting from this transaction, as described above, is not reflected in the pro forma interest expense per Exhibit Wolfram-2 Reference Schedule 2.15. As of March 1, 2011 when the Application for this general adjustment in rates was filed with the Commission there was still uncertainty about whether a limited waiver of Section 5.09(C) of the Revolving Credit Agreement between Big Rivers Electric Corporation and

CoBank, ACB could be obtained to enable this transaction to move forward. CoBank agreed to grant such a waiver on March 11, 2011, and Big Rivers' board of directors approved the transaction on March 18, 2011.

e. No RUS approval, written or otherwise, was required for this transaction. Big Rivers is not aware of any agreement with RUS that requires such authorization prior to using the Transition Reserve in this manner. Section 3.4 of the Amended and Consolidated Loan Contract between Big Rivers Electric Corporation (the "Borrower") and the United States of America (acting by and through the Administrator of the Rural Utilities Service) grants the Borrower the right to prepay RUS Notes in whole or in part in the sole discretion of the Borrower without penalty or prepayment premium.

Witness) Mark A. Hite

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-4)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

CoBANK

5500 South Quebec Street
Greenwood Village, CO 80111
800-542-8072
www.cobank.com

March 11, 2011

Mr. Mark Bailey
President and Chief Executive Officer
Big Rivers Electric Corporation
P.O. Box 24
Henderson, KY 42419-0024

RE: Limited waiver of Section 5.09(C) of that certain Revolving Credit Agreement between Big Rivers Electric Corporation ("Big Rivers") and CoBank, ACB ("CoBank") dated as of July 16, 2009

Dear Mr. Bailey.

Big Rivers and CoBank are parties to that certain Revolving Credit Agreement, dated as of July 16, 2009, as may be amended from time to time (the "**Revolving Credit Agreement**"). All capitalized terms used herein shall have the meanings assigned to them in the Revolving Credit Agreement. Pursuant to Section 5.09(C) of the Revolving Credit Agreement, Big Rivers is required to maintain a Thirty-Five Million Dollar ($35,000,000) transition reserve which is to be utilized to offset any costs and expenses related to a termination of a Smelter Power Contract (the "**Transition Reserve**"). Big Rivers has requested that CoBank provide a limited waiver of the requirement to maintain the Transition Reserve (the "**Limited Waiver**"), so that it may voluntarily prepay the RUS 2009 Promissory Note Series A, dated as of July 16, 2009 (the "**RUS Note**"), thereby avoiding interest expense on the portion of the RUS Note being prepaid.

To induce CoBank to supply the Limited Waiver, pursuant to Section 5.06(I) of the Revolving Credit Agreement Big Rivers represents and warrants that:

- No event of default currently exists, nor would exist as the result of CoBank and Big Rivers agreeing to, executing, delivering and implementing the Limited Waiver and any subsequent voluntary prepayment of the RUS Note as described above, under (i) the Indenture, dated as of July 1, 2009, by and between Big Rivers and U.S. Bank National Association, as trustee, as may be amended from time to time, (ii) the Revolving Credit Agreement, (iii) the Amended and Consolidated Loan Contract, dated as of July 16, 2009, by and between Big Rivers and the United States of America, as may be amended from time to time, or (iv) any other material agreement or contract to which Big Rivers is a party; and
- The RUS Note permits voluntary prepayment, and Big Rivers has the ability to "claw back" such voluntary prepayments by foregoing quarterly payments under the RUS Note and applying those funds to replenish the Transition Reserve in the event that Big Rivers receives notice that a Smelter Power Contract is being terminated.

Pursuant to the terms of the Revolving Credit Agreement, including without limitation Section 9.01, and based on the foregoing representations, warranties and agreements, CoBank hereby provides the Limited Waiver of that Section 5.09(C) of the Revolving Credit Agreement to permit Big Rivers to use the amounts in the Transition Reserve to make voluntary prepayments on the RUS Note as described herein, subject to acceptance and performance by Big Rivers of the following terms, conditions and restrictions:

1. Except as otherwise set forth herein, all of the terms and provisions of the Revolving Credit Agreement are hereby ratified and shall remain in full force and effect.
2. This Limited Waiver shall be limited as expressly set forth herein and shall not be construed to be a waiver of, or obligate CoBank to waive any other provision of the Revolving Credit Agreement at any point in the future.
3. In accordance with Section 9.05 of the Revolving Credit Agreement, Big Rivers shall pay all costs and expenses incurred by CoBank with respect to the negotiation, execution, delivery and performance of this Limited Waiver, including CoBank's attorneys' fees and expenses.
4. Big Rivers shall pay all costs and expenses that it incurs with respect to the negotiation, execution, delivery and performance of this Limited Waiver.
5. The Transition Reserve shall be used by Big Rivers only for the purpose of voluntarily prepaying the RUS Note, except as otherwise provided for in the Revolving Credit Agreement.
6. Big Rivers shall (i) maintain a Transition Reserve of Thirty-Five Million Dollars ($35,000,000) in accordance with Section 5.09(C) of the Revolving Credit Agreement, (ii) voluntarily prepay at least Thirty-Five Million Dollars ($35,000,000) on the RUS Note using the Transition Reserve, or (iii) implement a combination of (i) and (ii) above totaling a minimum of Thirty-Five Million Dollars ($35,000,000).
7. If Big Rivers receives notice that a Smelter Power Contract is being terminated. and the Transition Reserve is less than Thirty-Five Million Dollars ($35,000,000), Big Rivers shall forego all immediately following quarterly payments under the RUS Note, as allowed by the RUS Note, until such time as the Transition Reserve is fully replenished to Thirty-Five Million Dollars ($35,000,000), less any amounts that have been distributed from the Transition Reserve to offset costs and expenses related to termination of a Smelter Power Contract, at which time the Limited Waiver, immediately and without any further action, shall be terminated and of no further effect.
8. Big Rivers shall notify CoBank of any amendments or modifications to the RUS Note, including, but not limited to, such amendments or modifications that would restrict Big Rivers' ability to forego future quarterly payments under the RUS Note.

[Rest of page intentionally left blank]

If you accept this Limited Waiver on the terms offered, please sign one copy and return it to me.

IT IS IMPORTANT THAT THIS DOCUMENT BE KEPT WITH YOUR ORIGINAL LOAN DOCUMENTATION.

Best Regards,

Jeffrey E. Childs

Jeffrey E. Childs
Assistant Vice President
CoBank, ACB

BIG RIVERS ELECTRIC CORPORATION	
Accepted By:	_______________________ **(signature)**
Name:	Mark A. Bailey
Title:	President and Chief Executive Office
Date:	_______________________

c: James M. Miller, Esq., Sullivan, Mountjoy, Stainback & Miller

Mark Hite

From: Childs, Jeffrey [jchilds@cobank.com]
Sent: Monday, January 24, 2011 1:14 PM
To: Mark Hite
Subject: RE: Big Rivers Electric Corporation

I understand. I'll wait a couple days and that way we can use recent unaudited data. Thanks.

Jeff

From: Mark Hite [mailto:Mark.Hite@bigrivers.com]
Sent: Monday, January 24, 2011 12:00 PM
To: Childs, Jeffrey
Subject: RE: Big Rivers Electric Corporation

As we've discussed, Big Rivers hasn't yet closed its books for December 2010. At this time, I'm uncomfortable estimating December's margins. We do hope to have a preliminary trial balance in a couple of days, at which time I will likely have number I feel comfortable giving you. Perhaps best to wait until the December books are closed... unaudited. At this time we do know that YTD Nov 2010, TIER was 1.11. And, I do believe 2010 MFIR will be at least 1.10, as required by the Indenture.

Thanks,
Mark

Mark A. Hite, CPA
VP Accounting
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42420
Corporate: 270-827-2561
Office Direct: 270-844-6149
Cell: 270-577-6815
Fax: 270-827-2558
Home: 812-853-0405

From: Childs, Jeffrey [mailto:jchilds@cobank.com]
Sent: Monday, January 24, 2011 12:51 PM
To: Mark Hite
Subject: RE: Big Rivers Electric Corporation

Mark,

I'm preparing a request to our credit approvals group to waive Section 5.09 (C) and I want to make sure they get the right information. Can you correct me if I'm wrong on the 2010 info below, and feel free to add any big picture/summary info (MFI, DSC, Equity to Assets, Net Margin, etc.) that you are comfortable disclosing?

- $4.8 million net margin thru November
- Preliminary projected net margin for 2010 of $8 million, thanks to strong December performance
- 2010 preliminary projected TIER of 1.15x

Thanks,

Jeff

From: Mark Hite [mailto:Mark.Hite@bigrivers.com]
Sent: Monday, January 24, 2011 11:16 AM
To: Childs, Jeffrey
Subject: RE: Big Rivers Electric Corporation

Thanks Jeff. The estimate below is fine. Have a great day, Mark

Mark A. Hite, CPA
VP Accounting
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42420
Corporate: 270-827-2561
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From: Childs, Jeffrey [mailto:jchilds@cobank.com]
Sent: Monday, January 24, 2011 12:06 PM
To: Mark Hite
Subject: RE: Big Rivers Electric Corporation

Mark,

I asked Steptoe and Johnson for an estimate of the legal fees for the waiver letter re the Transition Reserve and here's what they said:

"In terms of an estimate, assuming there is not a lot of push back from and negotiations with Big River, I would think that an upward end in the range of $3,000-$5,000 would be sufficient."

I assume that's alright with you given the large savings that you will achieve thru the use of the reserve to prepay the Series A Note. If not, let me know.

Thanks,
Jeff

From: Mark Hite [mailto:Mark.Hite@bigrivers.com]
Sent: Wednesday, January 19, 2011 4:00 PM
To: Childs, Jeffrey
Subject: FW: Big Rivers Electric Corporation

Hope you had a great day. As I haven't heard yet back from you from you, just wanted to ensure you received the email below, and the attachment. Thanks much, Mark

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Home: 812-853-0405

From: Mark Hite
Sent: Friday, January 14, 2011 1:10 PM
To: 'Childs, Jeffrey'
Cc: Ralph Ashworth; Travis Siewert
Subject: Big Rivers Electric Corporation

Good afternoon Jeff. Good to chat with you regarding Big Rivers' desire for CoBank to waive Section 5.09 (C) of the revolver, allowing Big Rivers to use such monies to voluntarily prepay the RUS 5.75% Series A Note, rather than maintaining the current $35 million Transition Reserve which is earning about 75 basis points. This action would save Big Rivers $1.75 million annually. Then, in the unlikely event that a smelter termination notice is subsequently received, a $35 million transition reserve will be fully re-established prior to such smelter termination, and the Section 5.09 (C) waiver will be automatically and immediately withdrawn . As promised, attached is draft letter agreement language for you to consider and edit as you deem appropriate. Once we get the language to our liking, we can then take it up the chain of command for final approval.

Let me know of any questions you may have regarding this matter. By the way, the next quarterly RUS 5.75% Series A Note payment date is 4/1/1.

Thanks,
Mark

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- $4.8 million net margin thru November
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I assume that's alright with you given the large savings that you will achieve thru the use of the reserve to prepay the Series A Note. If not, let me know.

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Jeff

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To: Childs, Jeffrey
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From: Mark Hite
Sent: Friday, January 14, 2011 1:10 PM
To: 'Childs, Jeffrey'
Cc: Ralph Ashworth; Travis Siewert
Subject: Big Rivers Electric Corporation

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Thanks,
Mark

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Home: 812-853-0405

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT___(LK-5)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 32) *Refer to the Labor_WP1 tab in the excel workbook provided in response to KIUC 1-37, which provides the total proforma labor (payroll) expense used to compute the labor and labor overheads expense proforma adjustment on Exhibit Wolfram-2 Reference Schedule 2.07.*

a. Please provide the equivalent total proforma labor (payroll) expense annualized at October 31, 2010, assuming no other post test year adjustments. Provide all computations, including assumptions, data, and electronic spreadsheets with formulas intact.

b. Please separate the Company's proposed proforma adjustment to labor and labor overheads expenses into an adjustment to annualize labor expenses at October 31, 2010 (based on the information provided in response to part (a) of this question) and each proposed post-test year proforma adjustment, e.g., "step increases and contract increases for the bargaining employees, and qualification increase for non-bargaining employees." Provide a description of each of these other post test year proforma adjustments and all source documents and computations, including assumptions, data, electronic spreadsheets with formulas intact, and actuarial reports.

c. Please demonstrate that the proforma adjustment is to labor and labor overheads expense only and not to the portion of such costs that is capitalized. If this is not the case, then please provide the Company's test year actual labor and labor overheads expense ratio.

Response)

a. Please see Big Rivers' response to Item 7d of the Commission Staff's Third Request for Information ("Staff's Third Request"), which provides normalized test year labor and labor overheads based on employees of record and their wage and salary rates as of October 31, 2010, the end of the test year, and the workpapers attached to the response to Item 7e of Staff's Third Request.
b. The attached schedule starts with the annualized labor expenses at October 31, 2010, that were reported in the workpapers attached in response to PSC 3-7e. The schedule then shows the changes in those expenses resulting from the change in employees of record that occurred from October 31, 2010, to December 31, 2010, the date used in determining the pro forma employees of record. The schedule next shows the amount of the post 10/31/10 pay adjustments, including the 1/2/11 pay adjustments and 2011 qualification increases for the salaried employees, and the 2011 annual and step increases under the labor agreement for the bargaining employees. The pro forma adjustment reflects the proration of the pay adjustments, based on their effective date, rather than normalization of these known adjustments. Normalization of the pay adjustments would have increased the pro forma adjustment by $872,521, from a total of $68,708,897 for pro forma labor and labor overheads, to a total of $69,581,418.
c. None of the $68,708,897 pro forma labor and labor overheads were assumed to be capitalized. The numerical summary below provides the calculation of the percent of test year labor and labor overhead capitalized, 1.505%.

Test Year Labor and Labor Overheads	
Expensed:	
Wages/Salaries	45,955,019
Benefits	22,128,984
	68,084,003
Capitalized:	
Wages/Salaries	705,158
Benefits	335,105
	1,040,263
Total:	
Wages/Salaries	46,660,177
Benefits	22,464,089
	69,124,266
Percent Test Year Labor and Labor Overheads Capitalized	**1.505%**

Witnesses) James V. Haner – Subparts a. and b.

Mark A. Hite – Subpart c.

Big Rivers Electric Corporation
Case No. 2011-00036

Salaried

			Labor	Overhead	Total	
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Annualized Pay Rates 10/31/10**					
2	Number of Employees 10/31/10	246	19,424,712	11,047,862	30,472,574	(See PSC 3-7e)
3	Transfer from Bargaining to Salaried	3	233,042	123,731	356,773	
4	Hired	1	49,642	30,502	80,144	
5	Terminated	(1)	(64,993)	(37,530)	(102,523)	
6	**Pro Forma Employees 12/31/10**	**249**	**19,642,403**	**11,164,565**	**30,806,968**	
7						
8	**Post 10/31/10 Pay Adjustments-Prorated**		**772,549**	**177,810**	**950,359**	
9	(includes 1/2/11 pay adjustments and 2011 qualification increases)					
10						
11	**Pro Forma Labor and Labor Overhead**		**20,414,952**	**11,342,375**	**31,757,327**	(See PSC 1-54)
12						
13						
14	**BARGAINING**					
15						
16	**Annualized Pay Rates 10/31/10**					
17	Number of Employees 10/31/10	360	24,726,328	12,125,150	36,851,478	(See PSC 3-7e)
18	Transfer from Bargaining to Salaried	(3)	(220,959)	(100,775)	(321,734)	
19	Hired	2	127,853	65,306	193,159	
20	Terminated	(2)	(129,961)	(61,978)	(191,939)	
21	**Pro Forma Employees 12/31/10**	**357**	**24,503,261**	**12,027,703**	**36,530,964**	
22						
23	**Post 10/31/10 Pay Adjustments-Prorated**		**349,051**	**71,555**	**420,606**	
24	(includes 2011annual and step increases under labor agreement)					
25						
26	**Pro Forma Labor and Labor Overhead**		**24,852,312**	**12,099,258**	**36,951,570**	(See PSC 1-54)
27						
28						
29	**TOTAL PRO FORMA**		**45,267,264**	**23,441,633**	**68,708,897**	(See PSC 1-54)
30						

The $68,708,897 total pro forma amount in the summary on page 72 of the workpapers provided in Big Rivers' updated response to PSC 1-54 on April 15, 2011, is identifcal to the pro forma amount listed above and identical to the pro forma amount listed in Big Rivers' response to PSC 2-21. All calculations are net of the City's share of HMP&L's Station Two. The amount of the City's share of HMP&L's Station Two attributable to labor versus overhead, in arriving at the breakdown of the total between labor and overhead above, was arrived at using the individual breakdown for each employee identified in the PSC 1-54 workpapers as having time charged to Henderson Station Two. The amount of the City's share of HMP&L's Station Two attributable to labor versus overhead, in arriving at the breakdown of the total between labor and overhead in Big Rivers' response to PSC 2-21, was arrived at using the total of the City's share of HMP&L's Station Two based on total labor and total overhead.

Case No. 2011-00036
Witness: James V. Haner
Attachment for Item KIUC 2-32(b)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-6)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 39) ***Refer to the Company's response to AG 1-20. Please respond to the question posed. The response referred to the Company's response to AG 1-18; however, the response to AG 1-18 addressed only the Company's proposed proforma adjustments for MISO related expenses and did not address the MISO amounts in the historic test year.***

Response) As noted in the response to AG 1-18, Big Rivers did participate in Midwest ISO markets prior to becoming a transmission-owning member of the Midwest ISO in December 2010. The revenue requirement does include other Midwest ISO-related costs booked in the test year. These costs are primarily associated with wholesale energy market activities that are incremental to and/or separate from the administrative costs reflected in Reference Schedule 2.14. The total amount of such costs is $105,366.57. See attached.

Additionally, upon further review of the Midwest ISO invoices, Big Rivers has identified certain costs included in the test year that are not related to the energy purchased or sold in the Midwest ISO market. These are:

MISO Membership Fee:	$15,000.00
MISO Telephone Connection	
Hardware & Installation One-Time Charge:	$4,700.00
Reliability Coordination Service Cost for Sept 2010:	$41,856.38
TOTAL	$61,556.38

These are non-recurring costs and are not included in the proposed pro forma adjustment.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Witness) John Wolfram

Big Rivers Electric Corporation
Case No. 2011-00036
MISO Expenses in Test Year

Invoice #	Invoice Date	Operating Period	Amount	Source
SCHEDULE 17 - Market Admin Fees				
Reverse Oct-09 Estimate		10/31/09-10/31/09	(4.20)	JE 11-013
1142551	11/24/09	10/31/09-11/06/09	524.39	JE 11-013
1143247	12/01/09	11/07/09-11/13/09	372.45	JE 11-013
1143954	12/08/09	11/15/09-11/17/09	106.92	JE 11-013
1144672	12/15/09	11/21/09-11/27/09	40.15	JE 11-013
1145372	12/22/09	11/28/09-12/04/09	510.33	JE 12-015
1146092	12/29/09	12/05/09-12/11/09	2,037.51	JE 12-015
1146832	01/05/10	12/12/09-12/18/09	2,362.85	JE 12-015
1147594	01/12/10	12/19/09-12/24/09	1,434.10	JE 12-015
1148333	01/19/10	12/26/09-12/31/09	128.38	JE 12-015
1149051	01/26/10	01/02/10-01/08/10	699.42	JE 01-014
1149770	02/02/10	01/09/10-01/15/10	1,156.17	JE 01-014
1150509	02/09/10	01/16/10-01/22/10	1,521.65	JE 01-014
1151251	02/16/10	01/23/10-01/29/10	2,085.28	JE 01-014
1151982	02/23/10	01/30/10-02/05/10	1,877.90	JE 02-012
1152717	03/02/10	02/06/10-02/12/10	2,334.11	JE 02-012
1153837	03/09/10	02/13/10-02/19/10	2,612.88	JE 02-012
1154595	03/16/09	02/20/10-02/26/10	2,219.04	JE 02-012
1155355	03/23/10	02/27/10-03/05/10	3,302.32	JE 03-013
1156118	03/30/10	03/06/10-03/12/10	2,414.94	JE 03-013
1156874	04/06/10	03/13/10-03/19/10	1,706.41	JE 03-013
1157614	04/13/10	03/20/10-03/26/10	2,079.19	JE 03-013
1158354	04/20/10	03/27/10-04/02/10	1,798.40	JE 04-013
1159092	04/27/10	04/03/10-04/09/10	1,259.49	JE 04-013
1159813	05/04/10	04/10/10-04/16/10	1,876.28	JE 04-013
1160544	05/11/10	04/17/10-04/23/10	2,065.99	JE 04-013
1161318	05/18/10	04/24/10-04/30/10	1,482.49	JE 04-013
1162054	05/25/10	05/01/10-05/07/10	2,648.03	JE 05-014
1162772	06/01/10	05/08/10-05/14/10	2,746.34	JE 05-014
1163491	06/08/10	05/15/10-05/21/10	2,539.63	JE 05-014
1164213	06/15/10	05/22/10-05/28/10	2,567.76	JE 05-014
1164959	06/22/10	05/29/10-06/04/10	2,273.26	JE 06-012
1166054	06/29/10	06/05/10-06/11/10	2,097.41	JE 06-012
1167503	07/06/10	06/12/10-06/18/10	2,485.24	JE 06-012
1168238	07/13/10	06/19/10-06/25/10	2,661.68	JE 06-012
1168954	07/20/10	06/26/10-07/02/10	2,486.82	JE 07-014
1169674	07/27/10	07/03/10-07/09/10	2,311.04	JE 07-014
1170394	08/03/10	07/10/10-07/16/10	2,339.43	JE 07-014
1171117	08/10/10	07/17/10-07/23/10	1,959.67	JE 07-014
1171856	08/17/10	07/24/10-07/30/10	2,144.20	JE 07-014
1172596	08/24/10	07/31/10-08/06/10	1,352.68	JE 08-014
1173360	08/31/10	08/07/10-08/13/10	1,178.21	JE 08-014
1174118	09/07/10	08/14/10-08/20/10	923.92	JE 08-014
1174879	09/14/10	08/21/10-08/27/10	1,140.12	JE 08-014
1175614	09/21/10	08/28/10-09/03/10	1,453.88	JE 09-015
1176330	09/28/10	09/04/10-09/10/10	1,309.77	JE 09-015
1177071	10/05/10	09/11/10-09/17/10	1,331.32	JE 09-015
1177839	10/12/10	09/18/10-09/24/10	1,547.54	JE 09-015
1178600	10/19/10	09/25/10-10/01/10	1,769.55	JE 09-015
1179357	10/26/10	10/02/10-10/08/10	2,375.93	JE 10-011
1180094	11/02/10	10/09/10-10/15/10	2,141.41	JE 10-011
1180837	11/09/10	10/16/10-10/22/10	2,134.87	JE 10-011
1181602	11/16/10	10/23/10-10/29/10	1,480.40	JE 10-011
Estimate Oct-10 not invoiced		10/30/10-10/31/10	537.99	JE 10-011
TOTAL SCHEDULE 17			**91,942.94**	

Booked to a/c 447 (Revenue) or 555 (Purch Power)

Big Rivers Electric Corporation
Case No. 2011-00036
MISO Expenses in Test Year

Invoice #	Invoice Date	Operating Period	Amount	Source
SCHEDULE 24 - Balancing Authority Fees				
REVERSE ESTIMATE		10/31/09-10/31/09	(0.53)	JE 11-013
4623:73602	11/27/06	10/31/09-11/06/09	73.69	JE 11-013
4663:73891	12/01/09	11/07/09-11/13/09	52.37	JE 11-013
4706:74164	12/08/09	11/15/09-11/17/09	15.16	JE 11-013
4743:74447	12/15/09	11/21/09-11/27/09	5.62	JE 11-013
4764:74768	12/22/09	11/28/09-12/04/09	61.74	JE 12-015
4803:75087	12/29/09	12/05/09-12/11/09	240.51	JE 12-015
4843:75341	01/05/10	12/12/09-12/18/09	266.93	JE 12-015
4883:75603	01/12/10	12/19/09-12/24/09	169.28	JE 12-015
4923:75885	01/19/10	12/26/09-12/31/09	15.15	JE 12-015
4963:76163	01/26/10	01/02/10-01/08/10	98.67	JE 01-014
5003:76446	02/02/10	01/09/10-01/15/10	162.95	JE 01-014
5043:76728	02/09/10	01/16/10-01/22/10	214.54	JE 01-014
5064:77001	02/16/10	01/23/10-01/29/10	293.81	JE 01-014
5084:77275	02/23/10	01/30/10-02/05/10	253.01	JE 02-012
5123:77563	03/02/10	02/06/10-02/12/10	307.35	JE 02-012
5183:77984	03/09/10	02/13/10-02/19/10	343.96	JE 02-012
5223:78303	03/16/09	02/20/10-02/26/10	292.17	JE 02-012
5244:78615	03/23/10	02/27/10-03/05/10	375.56	JE 03-013
5283:78899	03/30/10	03/06/10-03/12/10	261.95	JE 03-013
5323:79184	04/06/10	03/13/10-03/19/10	185.02	JE 03-013
5363:79464	04/13/10	03/20/10-03/26/10	225.37	JE 03-013
5403:79788	04/20/10	03/27/10-04/02/10	214.15	JE 04-013
5443:80106	04/27/10	04/03/10-04/09/10	185.55	JE 04-013
5483:80406	05/04/10	04/10/10-04/16/10	276.40	JE 04-013
5523:80983	05/11/10	04/17/10-04/23/10	304.32	JE 04-013
5563:81260	05/18/10	04/24/10-04/30/10	218.25	JE 04-013
5603:81567	05/25/10	05/01/10-05/07/10	307.23	JE 05-014
5643:81890	06/01/10	05/08/10-05/14/10	318.48	JE 05-014
5683:82210	06/08/10	05/15/10-05/21/10	294.80	JE 05-014
5723:82508	06/15/10	05/22/10-05/28/10	297.87	JE 05-014
5763:82807	06/22/10	05/29/10-06/04/10	258.19	JE 06-012
5823:83313	06/29/10	06/05/10-06/11/10	234.44	JE 06-012
5846:83919	07/06/10	06/12/10-06/18/10	276.50	JE 06-012
5883:84229	07/13/10	06/19/10-06/25/10	297.87	JE 06-012
5923:84650	07/20/10	06/26/10-07/02/10	279.56	JE 07-014
5963:85069	07/27/10	07/03/10-07/09/10	263.72	JE 07-014
6003:85392	08/03/10	07/10/10-07/16/10	266.75	JE 07-014
6043:85704	08/10/10	07/17/10-07/23/10	223.47	JE 07-014
6083:86064	08/17/10	07/24/10-07/30/10	244.74	JE 07-014
6123:86428	08/24/10	07/31/10-08/06/10	190.38	JE 08-014
6163:86723	08/31/10	08/07/10-08/13/10	175.10	JE 08-014
6184:87006	09/07/10	08/14/10-08/20/10	137.31	JE 08-014
6223:87283	09/14/10	08/21/10-08/27/10	169.26	JE 08-014
6263:87630	09/21/10	08/28/10-09/03/10	217.36	JE 09-015
6303:87972	09/28/10	09/04/10-09/10/10	197.17	JE 09-015
6343:88251	10/05/10	09/11/10-09/17/10	200.05	JE 09-015
6383:88503	10/12/10	09/18/10-09/24/10	232.71	JE 09-015
6423:88803	10/19/10	09/25/10-10/01/10	255.21	JE 09-015
6463:89127	10/26/10	10/02/10-10/08/10	289.91	JE 10-011
6503:89429	11/02/10	10/09/10-10/15/10	261.31	JE 10-011
6543:89728	11/09/10	10/16/10-10/22/10	260.62	JE 10-011
6583:90003	11/16/10	10/23/10-10/29/10	180.71	JE 10-011
ESTIMATED		10/30/10-10/31/10	65.67	JE 10-011
TOTAL SCHEDULE 24			**11,509.34**	

Booked to a/c 447 (Revenue) or 555 (Purch Power)

Big Rivers Electric Corporation
Case No. 2011-00036
MISO Expenses in Test Year

Invoice #	Invoice Date	Operating Period	Amount	Source
SCHEDULE 10 - ISO Cost Recovery Fees				
9308071110	11/06/09		80.44	V# 0548409
9337071110	12/07/09		93.30	V# 0548909
10006071110	01/08/10		8.55	V# 0549582
9435071110	02/05/10		40.86	V# 0549964
9462071110	03/05/10		419.42	V# 0550366
9495071110	04/07/10		117.05	V# 0550784
9525071110	05/07/10		657.83	V# 0551342
9554071110	06/07/10		125.34	V# 0551844
9587071110	07/08/10		93.57	V# 0552323
9616071110	08/06/10		99.87	V# 0552846
9649071110	09/08/10		69.74	V# 0553373
8400071110	10/07/10		108.32	V# 0553917
TOTAL SCHEDULE 10			**1,914.29**	
Booked to a/c 565.100 Transmission of Electricity to Others				
GRAND TOTAL			**105,366.57**	

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT___(LK-7)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 30) *Refer to the Depr WP1 tab in the excel workbook provided in response to KIUC 1-37, which provides the computation of annualized depreciation expense using the Company's existing depreciation rates and its proposed depreciation rates.*

a. Please confirm that the Company's calculations include depreciation expense on CWIP.

b. Please confirm that the amount of CWIP used in these calculations is $46.802 million.

c. Please provide the Company's definition and/or description of CWIP on which it computed depreciation expense. Please provide all references to the RUS USOA relied on for this definition and/or description of CWIP.

d. Please provide a description of each CWIP project, the amount of each CWIP project included for each CWIP/plant account listed on this schedule, and the actual (if now in service) or projected (if not now in-service) in-service date for each project. Please correlate the transmission CWIP projects on the referenced tab to those identified on Table 2 on page 10 of Mr. Crockett's testimony.

e. Please identify all testimony by Company witnesses in this proceeding that address the depreciation on CWIP.

f. Please identify and provide a copy of all authorities and precedent relied on for depreciation on CWIP.

g. Please provide all reasons in support of the Company's request for depreciation on CWIP.

h. Does the Company consider the CWIP a post test year adjustment to plant in service? If so, then please explain.

i. ***If the Company considers the CWIP to be a post test year adjustment to plant in service, then why did it not also propose a post test year adjustment to accumulated depreciation for depreciation expense after the test year?***

j. ***If the Company considers the CWIP to be a post test year adjustment to plant in service, why did it not also propose a post test year adjustment to reduce plant in service for retirements after the test year?***

Response)

a. Yes, in calculating pro forma depreciation expense, whether using existing depreciation rates or proposed depreciation rates, tab Depr WP1 included construction work in progress (CWIP) as a component of depreciable plant. CWIP was included in the depreciable plant balance in order to reflect depreciation expense on these "known and measurable" (prospective) additions to plant in service. Note that this CWIP is anticipated to be placed in service *prior to* the proposed rates in the proceeding being made effective. See the response to KIUC 2-29.

b. Yes, the amount of CWIP included in depreciable plant for the purpose of calculating pro forma depreciation expense was $46,802,137.

c. Please see Big Rivers' response to KIUC 2-29.

d. Please see the attached details of the $46,802,137 of CWIP at October 31, 2010, included in depreciable plant for the purpose of calculating pro forma depreciation expense. Big Rivers does not record CWIP by plant account. Also, prior to the Oracle R12 November 1, 2010, "go-live" date, CWIP reporting via the legacy AS400 for transmission and headquarters projects indicated an expected completion date, while the CWIP reporting via Oracle

11i for the generation projects did not. In Oracle R12, there is no CWIP reporting of the projected in-service date of a project. For the purpose of calculating pro forma depreciation expense, the October 31, 2010, CWIP balance was appropriately classified among the plant accounts.

e. Please see the response to Item 29. The pro forma adjustment for Depreciation Expenses, Schedule 2.06, clearly stated that CWIP was included, and the associated workpapers clearly set forth the $46,802,138 amount of CWIP.

f. Please see Big Rivers' response to KIUC 2-29.

g. Please see Big Rivers' response to KIUC 2-29.

h. For the purpose of calculating pro forma depreciation expense, CWIP at October 31, 2010, was included in depreciable plant balance in order to reflect depreciation expense on these "known and measurable" (prospective) additions to plant in service. Note that this CWIP is anticipated to be placed in service *prior to* the proposed rates in this proceeding being made effective. Any associated adjustment for retirements and accumulated depreciation was not "known and measurable"; as such details are not generally known prior to the project completion.

i. See the response to Subpart h. Adjusting accumulated depreciation was deemed irrelevant to this proceeding, as it has no impact on the proposed revenue requirement (i.e. no pro forma return on rate base was proposed or prepared.).

j. See the response to Subpart h.

Witness) Mark A. Hite

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT___(LK-8)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

Big Rivers Electric Corporation
Case No. 2011-00036
Statement of Electric Plant in Service
Twelve Months Ended October 21, 2010
Total Company

	Account Number	Title of Accounts	Beginning Balance	Additions	Retirements	Transfers	Ending Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	3555	POLES AND FIXTURES - KU	-	79,206.80			$79,206.80
2	3560	OVERHEAD CONDUCTOR & DEVICES	40,579,890.47	3,409,335.25	315,942.94		$43,673,282.78
3	3561	OVERHEAD CONDUCTOR & DEVICES	86,900.75				$86,900.75
4	3565	OVHD CONDUCTORS AND DEVICES - KU	-	104,571.36			$104,571.36
5	3890	LAND & LAND RIGHTS	407,251.23				$407,251.23
6	3900	STRUCTURES & IMPROVEMENTS	3,944,895.21	4,038.68			$3,948,933.89
7	3910	OFFICE FURNITURE & EQUIPMENT	623,124.71	16,847.84	50,069.63		$589,902.92
8	3912	COMPUTER EQUIPMENT AND SOFTWARE	6,815,319.81	486,500.43	138,648.45		$7,163,171.79
9	3916	OFFICE FURNITURE & EQUIP-REID, STA TWO	1,894.73				$1,894.73
10	3917	OFFICE FURNITURE & EQUIP-REID, GREEN, STA TWO	3,059.60				$3,059.60
11	3922	TRANSPORTATION EQUIPMENT	1,729,389.24	229,004.13	19,629.08	174,085.17	$1,764,679.12
12	3923	TRANSPORTATION EQUIPMENT-SPECIAL	1,257,239.84				$1,257,239.84
13	3930	STORAGE EQUIPMENT	98,765.68				$98,765.68
14	3940	TOOLS,SHOP & GARAGE EQUIPMENT	716,613.73	6,216.26	752.58		$722,077.41
15	3950	LABORATORY EQUIPMENT	221,278.64				$221,278.64
16	3960	POWER OPERATED EQUIPMENT	321,665.34	21,242.06			$342,907.40
17	3961	GO TRACT VEHICLE	183,073.76				$183,073.76
18	3970	COMMUNICATIONS EQUIPMENT	1,639,437.34	682.16			$1,640,119.50
19	3980	MISC EQUIPMENT	160,713.76	5,069.55	713.12		$165,070.19
20	3987	MISC EQUIPMENT-REID, GREEN, STATION 2	1,625.49				$1,625.49
21							
22		Total Plant in Service	1,906,895,512.43	66,422,882.34	29,991,845.39	292,442.29	1,943,034,107.09

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-9)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

KIUC Adjustment to Exclude Depreciation Expense on Retirements
$ Million

		Amount
Depreciation Expense on CWIP Additions - See Response to KIUC 1-37 Worksheet Tab Depr_WP1		2.313
Retirement Percentage For Test Year Additions - See Response to KIUC 2-31		
Retirements in Test Year	29.992	
Additions in Test Year	66.423	
Retirements as Percentage of Additions During the Test Year		-45.15%
Exclude Depreciation Expense on Retirements		(1.045)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

REDACTED
EXHIBIT __ (LK-10)

OF

LANE KOLLEN

RECEIVED
JUN 10 2011
PUBLIC SERVICE COMMISSION

CONFIDENTIAL – FILED UNDER SEAL

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-11)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 28) ***Please refer to line 400 of the schedule provided in the Company's response to PSC 1-19(b) for account 565100 Transmission of Electricity by Others. The Company's actual test year expense for this account was $3.064 million. Refer also to the Company's response to KIUC 1-43 and the Trial Bal tab in the workbook for 2011, 2012, 2013, and 2014 and the expense amount shown for this account in each of those years, which is substantially less than the test year. Please describe and quantify all reasons for the reductions in expense after the test year.***

Response) The charges to account 565100 represent transmission charges incurred for the transmission of Big Rivers' electricity over the transmission facilities owned by other utilities. The test year reflects transmission charges from Tennessee Valley Authority (TVA), Midwest ISO, E.ON U.S. LLC, and Kentucky Utilities Company that are quantified in the table below:

Vendor	**Amount (in thousands)**
Tennessee Valley Authority	$2,835
Midwest ISO	77
E.ON U.S. LLC	50
Kentucky Utilities Company	102
Test Year Total	$3,064

The $50,000 and $102,000 amounts reflected in the table above for E.ON U.S. LLC and Kentucky Utilities Company, respectively, are related to providing service to two separate locations of a Member's industrial customer. This total of $152,000 is invoiced, collected, and recorded in revenue as an offset to the expense reflected in account 565100 resulting in a zero impact to margins.

The $2.718 million of annual charges to account 565100 shown in the multi-year financial forecast provided by the Company in response to KIUC 1-43 reflects only the budgeted charge related to the TVA transmission reservation. Note that the TVA transmission reservation is primarily in support of Big Rivers' off-system sales activity, for which Big Rivers did not propose a pro forma adjustment in this proceeding.

Witness) Mark A. Hite

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-12)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

KIUC Adjustment to Depreciation Expense

ACCT	BALANCE 10/31/2010	COMPANY'S NEW YEARLY RATE	COMPANY'S NEW DEPRECIATION RATE	COMPANY'S PRO FORMA DEPRECIATION EXPENSE	VARIANCE	KIUC NEW YEARLY RATE	KIUC NEW DEPRECIATION RATE	KIUC PRO FORMA DEPRECIATION EXPENSE	KIUC ADJUSTMENT
3010	419.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3020	66,475.65	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3030	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3101	83,342.47	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3102	1,124,664.82	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3103	1,110,711.72	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3104	2,218,857.54	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3111	3,236,944.36	1.38	0.001150	44,669.83	(10,681.92)	1.17	0.000975	37,872.25	(6,797.58)
3112	18,977,054.83	1.38	0.001150	261,883.36	(62,624.28)	1.17	0.000975	222,031.54	(39,851.82)
3113	26,723,028.18	1.38	0.001150	368,777.79	(88,185.99)	1.17	0.000975	312,659.43	(56,118.36)
3114	73,073,034.47	1.38	0.001150	1,008,407.88	(241,141.01)	1.17	0.000975	854,954.50	(153,453.38)
3115	421,179.00	1.38	0.001150	5,812.27	(1,389.89)	1.17	0.000975	4,927.79	(884.48)
3116	577,533.07	1.38	0.001150	7,969.96	(1,905.86)	1.17	0.000975	6,757.14	(1,212.82)
3117	937,856.03	1.38	0.001150	12,942.41	(3,094.93)	1.17	0.000975	10,972.92	(1,969.49)
3119	693,609.79	1.38	0.001150	9,571.82	(2,288.91)	1.17	0.000975	8,115.23	(1,456.59)
3120	29,686.39	1.88	0.001567	558.10	26.59	1.54	0.001283	457.17	(100.93)
312A	220,240.55	2.28	0.001900	5,021.48	858.93	1.97	0.001642	4,338.74	(682.74)
3121	7,193,006.17	1.88	0.001567	135,228.52	6,444.94	1.54	0.001283	110,772.30	(24,456.22)
312B	5,061,431.08	2.28	0.001900	115,400.63	19,739.58	1.97	0.001642	99,710.19	(15,690.44)
3122	77,143,667.49	1.88	0.001567	1,450,300.95	69,120.73	1.54	0.001283	1,188,012.48	(262,288.47)
312C	121,989,593.12	2.28	0.001900	2,781,362.72	475,759.41	1.97	0.001642	2,403,194.98	(378,167.74)
3123	161,617,029.17	1.88	0.001567	3,038,400.15	144,808.86	1.54	0.001283	2,488,902.25	(549,497.90)
312D	113,968,704.31	2.28	0.001900	2,598,486.46	444,477.95	1.97	0.001642	2,245,183.47	(353,302.99)
3124	402,071,586.26	1.88	0.001567	7,558,945.82	360,256.14	1.54	0.001283	6,191,902.43	(1,367,043.39)
312E	268,650,680.12	2.28	0.001900	6,125,235.51	1,047,737.66	1.97	0.001642	5,292,418.40	(832,817.11)
3125	17,389,606.87	1.88	0.001567	326,924.61	15,581.09	1.54	0.001283	267,799.95	(59,124.66)
312F&312K	71,086,231.78	2.28	0.001900	1,620,766.08	277,236.30	1.97	0.001642	1,400,398.77	(220,367.31)
3126	2,554,464.97	1.88	0.001567	48,023.94	2,288.80	1.54	0.001283	39,338.76	(8,685.18)
312G	1,899,172.74	2.28	0.001900	43,301.14	7,406.78	1.97	0.001642	37,413.70	(5,887.44)
3127	376,268.58	1.88	0.001567	7,073.85	337.14	1.54	0.001283	5,794.54	(1,279.31)
3128	1,186,252.75	1.88	0.001567	22,301.55	1,062.88	1.54	0.001283	18,268.29	(4,033.26)
312J	15,438.27	2.28	0.001900	351.99	60.21	1.97	0.001642	304.13	(47.86)
3140	0.00	1.91	0.001592	0.00	0.00	1.54	0.001283	0.00	0.00
3141	4,310,530.58	1.91	0.001592	82,331.13	10,793.56	1.54	0.001283	66,382.17	(15,948.96)
3142	32,762,390.07	1.91	0.001592	625,761.65	82,037.02	1.54	0.001283	504,540.81	(121,220.84)
3143	57,679,599.22	1.91	0.001592	1,101,680.35	144,429.72	1.54	0.001283	888,265.83	(213,414.52)
3144	127,883,751.07	1.91	0.001592	2,442,579.65	320,220.92	1.54	0.001283	1,969,409.77	(473,169.88)
3145	4,991,571.10	1.91	0.001592	95,339.01	12,498.90	1.54	0.001283	76,870.19	(18,468.82)
3146	262,741.29	1.91	0.001592	5,018.36	657.91	1.54	0.001283	4,046.22	(972.14)
3147	18,495.15	1.91	0.001592	353.26	46.31	1.54	0.001283	284.83	(68.43)
3151	1,494,658.69	1.99	0.001658	29,743.71	5,835.15	1.08	0.000900	16,142.31	(13,601.40)
3152	8,552,676.77	1.99	0.001658	170,198.27	33,389.65	1.08	0.000900	92,368.91	(77,829.36)
3153	16,091,239.72	1.99	0.001658	320,215.67	62,820.20	1.08	0.000900	173,785.39	(146,430.28)
3154	35,070,442.41	1.99	0.001658	697,901.80	136,915.00	1.08	0.000900	378,760.78	(319,141.02)
3155	171,384.26	1.99	0.001658	3,410.55	669.09	1.08	0.000900	1,850.95	(1,559.60)
3159	43,548.07	1.99	0.001658	866.61	170.02	1.08	0.000900	470.32	(396.29)
3160	56,008.08	3.78	0.003150	2,117.11	1,092.16	3.77	0.003142	2,111.50	(5.61)
3161	1,227.09	3.78	0.003150	46.38	23.92	3.77	0.003142	46.26	(0.12)

KIUC Adjustment to Depreciation Expense

ACCT	BALANCE 10/31/2010	COMPANY'S NEW YEARLY RATE	COMPANY'S NEW DEPRECIATION RATE	COMPANY'S PRO FORMA DEPRECIATION EXPENSE	VARIANCE	KIUC NEW YEARLY RATE	KIUC NEW DEPRECIATION RATE	KIUC PRO FORMA DEPRECIATION EXPENSE	KIUC ADJUSTMENT
3162	849,312.17	3.78	0.003150	32,104.00	16,561.59	3.77	0.003142	32,019.07	(84.93)
3163	779,447.85	3.78	0.003150	29,463.13	15,199.23	3.77	0.003142	29,385.18	(77.95)
3164	749,577.26	3.78	0.003150	28,334.02	14,616.76	3.77	0.003142	28,259.06	(74.96)
3165	345,677.46	3.78	0.003150	13,066.61	6,740.71	3.77	0.003142	13,032.04	(34.57)
3166	308,147.79	3.78	0.003150	11,647.99	6,008.89	3.77	0.003142	11,617.17	(30.82)
3167	88,777.93	3.78	0.003150	3,355.81	1,731.17	3.77	0.003142	3,346.93	(8.88)
3169	107,699.80	3.78	0.003150	4,071.05	2,100.14	3.77	0.003142	4,060.28	(10.77)
3401	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3410	154,232.79	1.17	0.000975	1,804.52	(1,758.26)	1.17	0.000975	1,804.52	0.00
3420	1,436,911.63	9.10	0.007583	130,758.96	97,428.36	9.10	0.007583	130,758.96	0.00
3430	4,915,885.63	3.02	0.002517	148,459.75	27,057.04	3.02	0.002517	148,459.75	0.00
3440	1,102,963.67	0.50	0.000417	5,514.82	(19,076.86)	0.50	0.000417	5,514.82	0.00
3450	383,519.62	2.05	0.001708	7,862.15	(688.80)	2.05	0.001708	7,862.15	0.00
3460	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3500	13,151,946.52	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3501	704,868.36	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3520	5,817,594.61	1.90	0.001583	110,534.30	8,121.36	1.90	0.001583	110,534.30	0.00
3521	20,369.05	1.90	0.001583	387.01	28.43	1.90	0.001583	387.01	0.00
3522	157,304.64	1.90	0.001583	2,988.79	219.60	1.90	0.001583	2,988.79	0.00
3524	679,442.21	1.90	0.001583	12,909.40	948.50	1.90	0.001583	12,909.40	0.00
3530	78,645,358.50	2.23	0.001858	1,753,791.49	7,864.53	2.23	0.001858	1,753,791.49	0.00
3531	3,031,650.37	2.23	0.001858	67,605.80	303.16	2.23	0.001858	67,605.80	0.00
3532	5,573,659.91	2.23	0.001858	124,292.62	557.37	2.23	0.001858	124,292.62	0.00
3533	5,947,214.37	2.23	0.001858	132,622.88	594.72	2.23	0.001858	132,622.88	0.00
3534	22,364,145.19	2.23	0.001858	498,720.44	2,236.42	2.23	0.001858	498,720.44	0.00
3540	8,134,239.23	1.42	0.001183	115,506.20	(69,954.45)	1.42	0.001183	115,506.20	0.00
3541	146,747.32	1.42	0.001183	2,083.81	(1,262.03)	1.42	0.001183	2,083.81	0.00
3550	42,097,383.75	2.06	0.001717	867,206.11	(496,749.12)	2.06	0.001717	867,206.11	0.00
3551	234,314.24	2.06	0.001717	4,826.87	(2,764.91)	2.06	0.001717	4,826.87	0.00
3560	43,673,282.78	1.69	0.001408	738,078.48	(340,476.91)	1.69	0.001408	738,078.48	0.00
3561	86,900.75	1.69	0.001408	1,468.62	(677.48)	1.69	0.001408	1,468.62	0.00
3890	407,251.23	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3900	3,948,933.89	2.84	0.002367	112,149.72	9,888.13	2.84	0.002367	112,149.72	0.00
3910	589,902.92	17.12	0.014267	100,991.38	94,443.46	17.12	0.014267	100,991.38	0.00
3912	7,163,171.79	10.29	0.008575	737,090.38	657,579.17	10.29	0.008575	737,090.38	0.00
3913	0.00	0.00	0.000000	0.00	0.00	0.00	0.000000	0.00	0.00
3916	1,894.73	17.12	0.014267	324.38	303.35	17.12	0.014267	324.38	0.00
3917	3,059.60	17.12	0.014267	523.80	489.84	17.12	0.014267	523.80	0.00
3922	1,764,679.12	4.39	0.003658	77,469.41	(21,698.50)	4.39	0.003658	77,469.41	0.00
3923	1,257,239.84	6.14	0.005117	77,194.53	6,542.68	6.14	0.005117	77,194.53	0.00
3930	98,765.68	4.40	0.003667	4,345.69	819.76	4.40	0.003667	4,345.69	0.00
3940	722,077.41	4.61	0.003842	33,287.77	12,708.56	4.61	0.003842	33,287.77	0.00
3950	221,278.64	4.41	0.003675	9,758.39	3,430.71	4.41	0.003675	9,758.39	0.00
3960	342,907.40	3.70	0.003083	12,687.57	1.37	3.70	0.003083	12,687.57	0.00
3961	183,073.76	3.70	0.003083	6,773.73	0.73	3.70	0.003083	6,773.73	0.00
3970	1,640,119.50	4.35	0.003625	71,345.20	0.00	4.35	0.003625	71,345.20	0.00
3980	165,070.19	11.80	0.009833	19,478.28	10,499.12	11.80	0.009833	19,478.28	0.00
3986	0.00	11.80	0.009833	0.00	0.00	11.80	0.009833	0.00	0.00

KIUC Adjustment to Depreciation Expense

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	3987	1,625.49	11.80	0.009833	191.81	103.39	11.80	0.009833	191.81	0.00
	312 L-P	3,208,938.00	20.22	0.016850	648,847.26	588,198.33	19.31	0.016092	619,645.93	(29,201.33)
	312 V-Z	868,755.00	14.39	0.011992	125,013.84	109,459.65	19.31	0.016092	167,756.59	42,742.75
	3525	185,107.45	1.90	0.001583	3,517.04	258.41	1.90	0.001583	3,517.04	0.00
	3535	6,511,340.66	2.23	0.001858	145,202.90	651.14	2.23	0.001858	145,202.90	0.00
	3545	312,557.79	1.42	0.001183	4,438.32	(2,688.00)	1.42	0.001183	4,438.32	0.00
	3555	79,206.80	2.06	0.001717	1,631.66	(934.64)	2.06	0.001717	1,631.66	0.00
	3565	104,571.36	1.69	0.001408	1,767.26	(815.23)	1.69	0.001408	1,767.26	0.00
CWIP										
	312	18,256,534.04	1.88	0.001567	343,222.84	16,357.85	1.54	0.001283	281,150.62	(62,072.22)
	312 env	4,191,946.40	2.28	0.001900	95,576.38	16,348.59	1.95	0.001625	81,742.95	(13,833.43)
	3530	7,475,859.18	2.23	0.001858	166,711.66	747.59	2.23	0.001858	166,711.66	0.00
	3910	2,165,170.04	17.12	0.014267	370,677.11	346,643.72	17.12	0.014267	370,677.11	0.00
	3912	11,736,080.31	10.29	0.008575	1,207,642.66	1,077,372.17	10.29	0.008575	1,207,642.66	0.00
	3970	2,976,548.00	4.35	0.003625	129,479.84	0.00	4.35	0.003625	129,479.84	0.00
Total Before Retirements		1,989,360,277.56			42,532,088.77	5,475,111.24			36,721,956.92	(5,810,131.85)
Retirements										
	312	-8,243,351.13	1.88	0.001567	(154,975.00)		1.54	0.001283	(126,947.61)	28,027.39
	312 env	-1,892,784.58	2.28	0.001900	(43,155.49)		1.95	0.001625	(36,909.30)	6,246.19
	3530	-3,375,565.81	2.23	0.001858	(75,275.12)		2.23	0.001858	(75,275.12)	0.00
	3910	-977,636.66	17.12	0.014267	(167,371.40)		17.12	0.014267	(167,371.40)	0.00
	3912	-5,299,178.40	10.29	0.008575	(545,285.46)		10.29	0.008575	(545,285.46)	0.00
	3970	-1,343,997.18	4.35	0.003625	(58,463.88)		4.35	0.003625	(58,463.88)	0.00
Total Retirements		-21,132,513.76			(1,044,526.35)				(1,010,252.77)	
Adjustments After Retirements					41,487,562.42	4,430,584.89			35,711,704.15	(5,775,858.27)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT___(LK-13)

OF

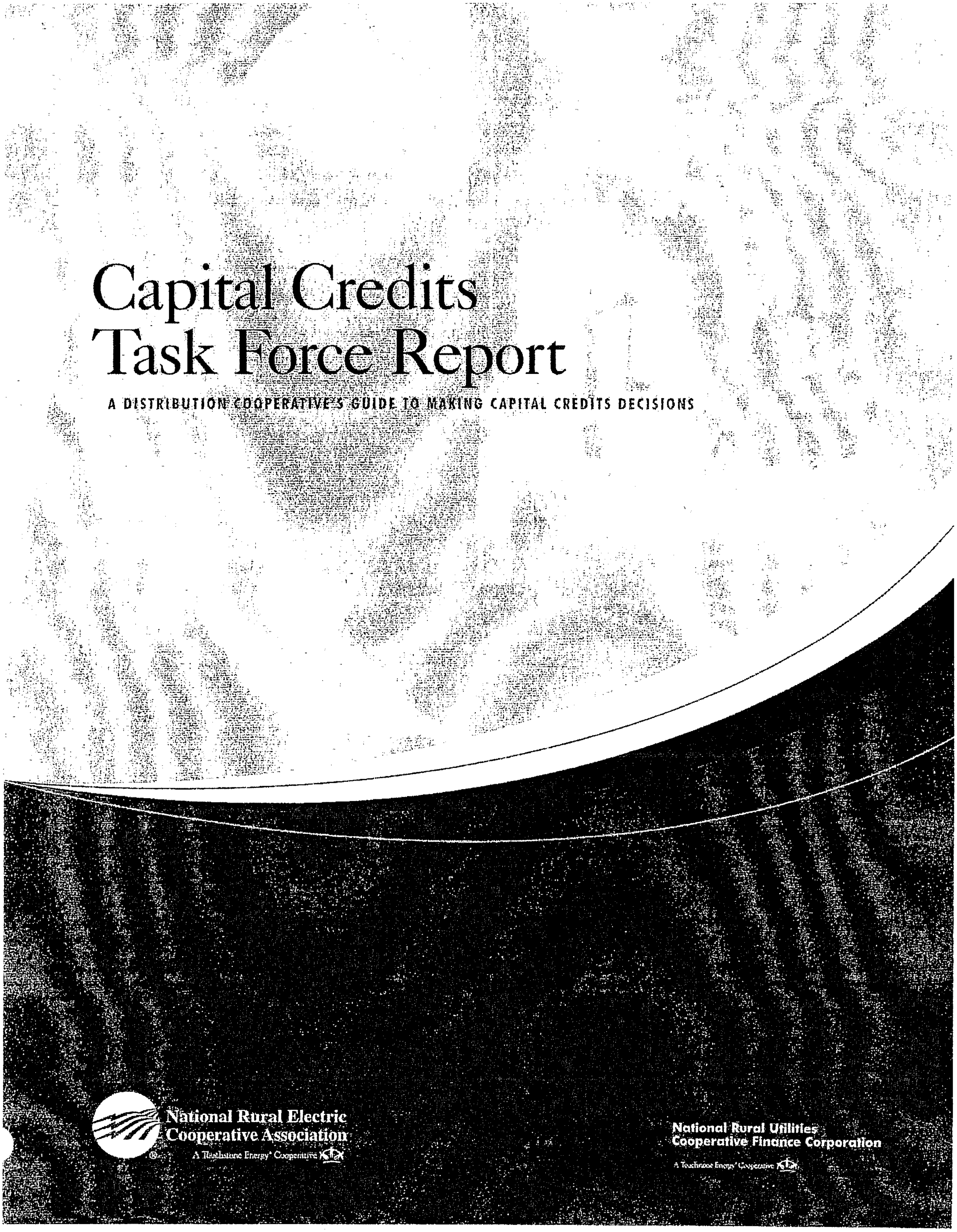
LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011



Capital Credits Task Force Report

A DISTRIBUTION COOPERATIVE'S GUIDE TO MAKING CAPITAL CREDITS DECISIONS

National Rural Electric Cooperative Association
A Touchstone Energy® Cooperative

National Rural Utilities Cooperative Finance Corporation
A Touchstone Energy® Cooperative

In Memoriam

Stephen J. Piecara

The Capital Credits Task Force dedicates this report and the work it represents to the memory of Stephen J. Piecara. As executive director of Tax, Finance & Accounting Policy for NRECA, Steve was a valuable resource for the task force and for the entire cooperative network. He had a detailed knowledge of tax, finance and accounting principles, rules and regulations, especially as applied to electric cooperatives. Even more important, he was skilled at sharing his knowledge in ways that anyone could understand. Whatever value this report has can in large part be attributed to Steve's contributions, his wisdom and his commitment. He was a supremely competent advocate for electric cooperatives.

More than that, Steve was a truly nice and decent person. He was never too busy to take the time to answer a question, or even the same question again. It was a pleasure for all of us to work with him. He will be greatly missed and long remembered.

Capital Credits Task Force Report

A Distribution Cooperative's Guide to
Making Capital Credits Decisions

National Rural Electric
Cooperative Association

National Rural Utilities
Cooperative Finance Corporation

January 2005

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A Message from the Task Force

Back Row (Left to Right): James Andrews, Joe Cole, Dave Eames, Roger Yoder, R. Layne Morrill, Jack Preston, Charles Barton, Mike Bash, Bill Kopacz, John R. Smith, Charles Lopez

Front Row (Left to Right): Eunice Bartels, Gene Smith, Debbie Robinson

Not Pictured Michael Whiteside, Gary Voigt, Denise Barrera

The well-known business scandals of recent years present a challenge and an opportunity to explain why cooperatives are different from other forms of business. A cooperative's capital credits policy and practices can clearly demonstrate this authentic difference.

Establishing a capital credits policy is one of the most important responsibilities of a co-op's board of directors. It requires the board to make important decisions, not only about allocating and retiring capital credits, but also about the co-op's capital structure. This report has been developed to assist cooperatives in making these key decisions.

In December 2003, CFC and NRECA appointed the Capital Credits Task Force to conduct a study of capital credits issues and provide guidance to cooperatives. During our deliberations we reviewed extensive information on capital credits issues. We sought the advice of many experts, including lawyers, accountants, tax advisers, data processing specialists and the RUS staff. We also sought the input of other co-ops and conducted two surveys to determine practices and concerns.

Each cooperative has unique circumstances that affect its capital credits decisions, but the task force found that there are many common issues. Wherever possible, the task force has provided information about alternative approaches to these issues. We also offer our recommendations where we believe that the appropriate action is clear and applicable in most situations. The task force believes very strongly that every staff member and every co-op director should understand the co-op's capital credits policy, be able to explain it to members, and be able to answer any questions that members might have.

We urge each electric cooperative to use this report as a guide to a thorough review of its capital credits policy and practices. Such a review is worthy of each co-op's time and attention because capital credits demonstrate—in a tangible and powerful way—the cooperative difference that is central to the future success and growth of the entire rural electric cooperative network.

J.E. "Gene" Smith *Chairman*	James Andrews	Mike Bash	Bill Kopacz	John R. Smith
	Denise Barrera	Joe Cole	R. Layne Morrill	Gary Voigt
	Charles Barton	Dave Eames	Jack Preston	Michael Whiteside
	Eunice Bartels	Charles Lopez	Debbie Robinson	Roger Yoder

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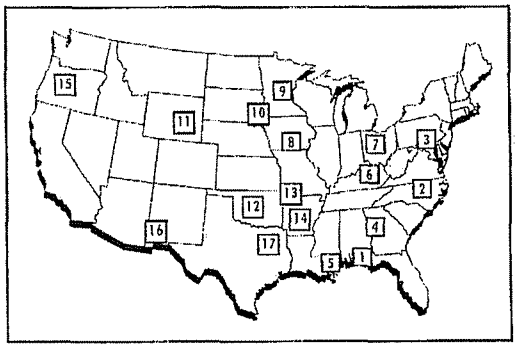
Carrollton, Georgia

Their understanding of the issues facing the electric cooperative network and their willingness to assist the task force in its deliberations is much appreciated.

Thanks also to RUS, CFC and NRECA for providing staff support for the project, including project coordinators Rich Larochelle, CFC, and Mike Ganley, NRECA; Diana Alger and Patrick Sarver, RUS; Steve Piccara, Bob Patton, and Ty Thompson, NRECA; and Lynn Midgette, Claudia Phillips, Tom Nusbaum, Marty Crowson, Jim Kaufman and Beth Ann Johnson, CFC; and to Patricia Lloyd Williams and Vicki Albizo for editorial services.

Task Force Members



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1. Gene Smith *CEO*
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Region I

2. James Andrews *Director*
Randolph EMC, Liberty, NC

3. Joe Cole *Manager, Finance & Corporate Services*
Adams EC, Gettysburg, PA

Region II

4. Michael Whiteside *President & CEO*
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5. Charles Lopez *Director*
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8. John R. Smith *CEO*
Pella CEA, Pella, IA

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10. Eunice Bartels *Director*
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16. Denise Barrera *Manager of Finance*
Columbus EC, Deming, NM

17. Debbie Robinson *CEO & General Manager*
Wood County EC, Quitman, TX

Recommendations of the Task Force

Following is a summary of the task force's 12 recommendations.

Strategic Goals

A Board-Approved Policy: Every electric cooperative should have a policy for annually allocating capital credits and, subject to the board of directors' discretion and the cooperative's financial condition, annually retiring capital credits.

Equity Management Plan: Every electric cooperative should develop and implement an equity management plan that supports its capital credits policy based on the co-op's equity and debt requirements, financial performance and competitive situation. The equity management plan should include rates that will generate adequate cash to provide capital credits retirements.

Adequate Equity Level: Each electric cooperative should seek to maintain an equity level adequate to retire capital credits on an annual basis and meet the goals and requirements of its equity management plan. The task force suggests that a reasonable equity level for most distribution systems is in the range of 30 to 50 percent, depending on the cooperative's financial and competitive situation.

Permanent Equity: The development of permanent equity should not be a goal of a cooperative's capital credits policy. Any advantages of permanent equity, such as building a cooperative's equity level or developing reserves, can be achieved in more direct ways that do not involve the same tax, takeover or other risks inherent in a policy of permanent equity.

Allocating Capital Credits

Member Notification: Cooperatives should notify members in writing of the dollar amount of annual capital credits allocations.

Contractual Forfeiture: Electric cooperatives should not enter contracts that require members to forfeit the right to capital credits in return for other considerations, such as reduced rates.

Retiring Capital Credits

Selecting Retirement Method Based on Goals: Each cooperative should choose a retirement method that will help the co-op achieve its goals, recognizing the effect the tenure and age of its members has on the perception of the value of membership in the cooperative. The task force strongly recommends that each cooperative know the percentage of its current membership receiving a capital credits retirement each year and seek to maximize that percentage.

Discount Special, Not General, Retirements: If an electric cooperative chooses to make special retirements, such as retirements to estates, the amount of the retirement should be discounted to reflect the time value of money. Cooperatives should not offer discounted general retirements.

Recommended Discount Rate: If a cooperative makes discounted capital credits retirements, the task force suggests that the discount rate selected should be based on the cooperative's weighted cost of capital, which includes the cost of equity and the cost of debt.

Age of Members: Electric cooperatives should not make special capital credits retirements based solely on the age of the member.

Compliance

Director Flexibility and Discretion: Every electric cooperative should review its bylaws, state laws and other applicable governing factors in terms of the impact on capital credits policies. If a cooperative's bylaws do not permit the board to exercise sufficient discretion regarding the method for allocating or retiring capital credits, the cooperative should consider seeking changes to give directors such flexibility in determining capital credits policies.

Maximizing the Benefits of Capital Credits Decisions

Communications Plan: Every cooperative should have a communications plan for educating members about capital credits and the cooperative's capital credits policies. Every director and each employee should understand the policy and be able to explain how it works and why it was adopted to members who have questions.

Executive Summary

In 1976, the first Capital Credits Study Committee issued a comprehensive report addressing many questions concerning capital credits. While the information in that report continues to be valid, since that time there have been many new developments, such as:

- Demographic changes among cooperative consumers,
- An increase in the use of discounting of capital credits retirements,
- Interest in developing permanent equity,
- An increased awareness of alternative retirement methods that may better demonstrate cooperative value to today's consumers, and
- Diversification into additional services.

In December 2003, the NRECA and CFC boards of directors appointed the Capital Credits Task Force to conduct a new capital credits study. The 17-member task force includes seven CEOs, five CFOs and five directors from co-ops representing the diversity of the electric cooperative network in terms of size and geographic location. It includes representatives from generation and transmission (G&T) cooperatives and distribution cooperatives.

In addition to reviewing the extensive information already available on capital credits, the task force enlisted the assistance of legal, tax, finance and accounting experts as well as the RUS staff to advise it on relevant issues. It sought and received input from the cooperative network through many channels, including separate surveys of distribution cooperatives and G&T cooperatives to identify their current practices and concerns.

While every cooperative has unique circumstances that affect capital credits decisions, the task force found many common issues. In its report, the task force addresses basic issues, evaluates alternative approaches and guides the co-op through the process of establishing a comprehensive policy.

Capital Credits Basics

Capital credits are the primary source of equity for most cooperatives, and allocating and retiring capital credits are two of the practices that distinguish cooperatives from other businesses. In 2003, electric distribution cooperatives returned $351 million in general capital credits retirements to consumers and $94 million in special retirements, primarily to estates.

Adopting and implementing a capital credits policy are key responsibilities of a co-op's board of directors and management. As the elected representatives of the members, directors must understand the co-op's capital credits policy and be able to explain why it was adopted and how it works to members who have questions. Management and staff are responsible for executing the board's policy. In doing so, a cooperative will face important decisions, including:

- What funds will be allocated to members,
- How funds will be allocated,
- How members will be notified of their allocations,
- What amount of capital credits to retire each year,
- Which retirement method to use,
- Whether to make special retirements,
- Whether to discount any retirements and, if so, the discount rate to use, and
- Which approach to retiring capital credits will maximize the value for the co-op and its members.

The board should also establish an equity management plan to support capital credits policies that allows it to balance equity and debt effectively to meet a variety of financial needs and criteria, including:

- Maintaining financial strength,
- Meeting mortgage requirements,
- Funding new construction,
- Retiring capital credits, and
- Ensuring fairness across generations.

Allocating Capital Credits

To qualify for federal tax-exempt status under Internal Revenue Code (IRC) Section 501(c)(12), a co-op generally must allocate capital credits to patrons each year and maintain records sufficient to reflect the equity of each member in the assets of the cooperative. State statutes and regulations and the cooperative's bylaws may impose additional allocation requirements and restrictions.

Audit guidelines issued by the Internal Revenue Service require a cooperative to allocate operating margins. Depending on circumstances, the board may have some discretion in choosing whether to allocate other patronage-sourced margins, non-patronage sourced margins or losses.

Co-ops may allocate capital credits on a variety of bases, provided that the basis is fair and equitable to patrons, including:

- Value (dollar amount of purchases),
- Quantity (kilowatt-hours or other measure), or
- Cost of service (contribution to margins).

A cooperative may use different allocation methods for different customer classes, but the same method must be used for all customers within a class.

A co-op must keep adequate records of each member's rights and interests in the cooperative's assets, including capital credits balances and a history of patronage. A co-op cannot terminate a member's rights and interests if the member moves or otherwise terminates membership, so the co-op must maintain records for former members until their capital credits are retired.

There are no requirements under Section 501(c)(12) for an exempt co-op to notify patrons of capital credits allocations, although many choose to do so, and the Capital Credits Task Force specifically recommends such annual notification as an important best practice. A taxable cooperative is required to give each member a written notice of the specific dollar amount within 8 1/2 months from the end of the co-op's tax year in order to claim a patronage dividend exclusion against its patronage-sourced margins.

Retiring Capital Credits

There are good business reasons to retire capital credits. It provides tangible evidence of members' ownership in the cooperative and demonstrates the difference between cooperatives and other organizations. Since the funds members invest in the cooperative do not earn dividends or other financial remuneration, retiring capital credits is a way to ensure that each generation of members pays its own way by providing its own equity. Failure to retire capital credits can have a negative impact on public relations and even lead to litigation or a hostile takeover if unhappy members try to recover their investment in the cooperative.

There are also legal reasons to retire capital credits in order to preserve a cooperative's status under the tax laws, but the IRS and the courts give cooperative boards considerable discretion in determining when to retire capital credits.

The board determines whether the co-op is in a financial position to retire capital credits and, if so, the dollar amount to retire in a given year. That decision is influenced by a number of factors, including:

- The co-op's financial performance,
- Its equity management plan,
- Rate competitiveness, and
- Regulatory bodies.

Other considerations include lender requirements and the views of the financial markets, both of which influence the cooperative's ability to obtain funds in the future. The board may choose to retire a percentage of the previous year's margins, capital credits allocated for specific years or a specific dollar amount.

Unless the bylaws or other authority specify retirement procedures, the board decides how capital credits are returned. In determining a method, the board should consider factors such as:

- **Cooperative philosophy.** Who should provide equity to the co-op, current and newer members or longer-term and former members?
- **Membership expectations.** Do the members expect to receive a retirement every year?
- **Demographics.** Is the membership of the cooperative stable, or is the rate of turnover high?
- **Customer classes.** Are sales predominantly to residential consumers, or are there significant sales to commercial customers?
- **Cooperative's accounting procedures.** Can the cooperative's accounting system and data service provider easily implement the method chosen?
- **Sellout exposure.** Could failure to retire capital credits lead to internal or external pressure to sell the cooperative?

Common retirement methods for general retirements include:

- First-in, first-out (FIFO),
- Percentage of total allocated capital credits,
- Percentage/FIFO hybrid, and
- FIFO/Last-in, first-out (LIFO) hybrid.

While FIFO continues to be the most commonly used method, the use of hybrid approaches is increasing because they provide benefits to current consumers. The Capital Credits Task Force recommends that before a cooperative retires capital credits in any year, it should know the percentage of its current members that will receive a capital credits refund, and select a retirement method or hybrid of methods that will maximize that percentage.

The board may decide as part of its policy to authorize special retirements of capital credits to recognize special circumstances, such as the death of a member. A special retirement allows the cooperative to make a payment sooner than it otherwise would. However, there is a real cost to the other members of the cooperative to retire capital credits out of sequence, and there is a benefit to the member to receive money sooner than the member would otherwise. Discounting special retirements to reflect the time value of money provides a fair way to recognize special circumstances while continuing to treat members equitably.

If a cooperative elects to discount capital credits retirements, the board must then choose the appropriate discount rate. It is important that the board consider this issue carefully, because the discount rate is the key to making discounted retirements fair and equitable. Too high a rate penalizes the member. Too low a rate penalizes the cooperative and its remaining members.

There is no one standard that is appropriate for every cooperative in every situation. The measure chosen should be easy to calculate, easy to explain and defensible. It should be fair to members both individually and collectively. The Capital Credits Task Force recommends that cooperatives use their own weighted average cost of capital as the discount rate.

Compliance Issues

A cooperative's policy for allocating and retiring capital credits must comply with applicable state and federal laws as well as the co-op's articles of incorporation and bylaws. The policy should also take into consideration the requirements of lenders and the financial markets. Directors should understand the legal and financial consequences of decisions they make about capital credits.

Maximizing the Benefit of Capital Credit Retirements

The act of distributing capital credits retirements offers an opportunity to address the special value of co-op membership. Basic knowledge of the characteristics of its membership, especially the age and tenure of members, can help a co-op devise capital credits policies and communications programs that will maximize the benefit of capital credits retirements.

A well-designed communications plan can help members understand what they are receiving. Communications materials should answer questions from the member's perspective, such as:

- What are capital credits?
- Why is it important for electric cooperatives to allocate and retire capital credits?
- How do capital credits benefit the cooperative and membership?
- Who receives capital credits allocations?
- When and how are capital credits returned?

In addition to written materials, the Capital Credits Task Force recommends that cooperatives take the time and devote the effort to ensure that every co-op employee and every co-op director understands the co-op's capital credits policy and is able to explain it to co-op members.

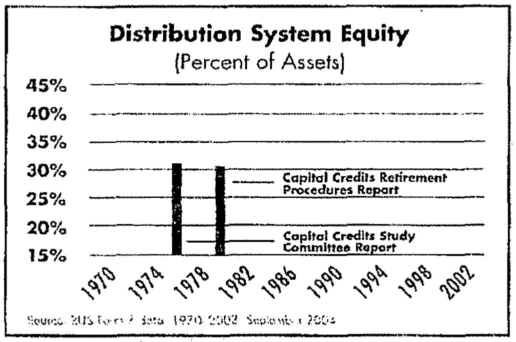
Thoughtful timing and the method of the distribution can maximize the benefit of that communication. The best approach for an individual co-op depends on what it wants to accomplish, demographics and the size of the distributions. For example, the co-op may issue retirements at a time when members will appreciate extra money or when the cooperative wants to draw attention to cooperative principles. The co-op can issue the retirement as a check or bill credit effectively, depending on its goals and communications plan.

Members, nonmembers and the public respond very favorably to the concept, principles and values that electric cooperatives offer consumers. An effective capital credits policy can help build member loyalty and educate consumers about the advantages of cooperative membership.

Origins of the Capital Credits Task Force

Electric cooperatives were born of necessity. They have succeeded for almost 70 years because they conduct business in accordance with core principles and values that put the consumer first. The foremost goal of every electric cooperative is to deliver power reliably at a reasonable cost. Co-ops have adopted a basic set of principles to guide their efforts to achieve that goal. Returning the funds members invest in the cooperative—capital credits—to the members is an important part of the cooperative philosophy.[1]

In the early years of the rural electric program, cooperatives were seldom able to return capital credits, because systems needed to retain equity in order to meet member needs and build financial strength. By the early 1970s, however, the composite equity of electric distribution systems approached 35 percent. Yet in 1975 only 127 systems out of 1,050 borrowers reporting to the Rural Electrification Administration (REA)[2] made general capital credits retirements. Cooperative leaders recognized that it was time to address this issue. The National Rural Electric Cooperative Association (NRECA) and the National Rural Utilities Cooperative Finance Corporation (CFC) jointly commissioned the first Capital Credits Study Committee in 1974 to investigate the issues regarding capital credits and to make recommendations that cooperatives could incorporate into their own objectives, policies and programs. The committee report,[3] issued in February 1976, was the first document to address the legal, accounting and philosophical aspects of equity management, capital credits allocations and capital credits retirements in a comprehensive manner.



Since the original capital credits studies in 1976 and 1980, co-ops have substantially increased equity levels.

The first Capital Credits Study Committee succeeded in focusing attention on capital credits issues, but many co-ops needed more information about the procedural aspects of retirement. In 1980, the Capital Credits Retirement Procedures Task Force was appointed to evaluate alternatives and develop guidelines for co-ops considering a retirement program. The task force report,[4] issued in August 1980, provided a thorough examination of retirement issues and made 12 specific recommendations related to administering capital credits policies.

The original Capital Credits Study Committee based its deliberations on the need for member understanding and support and the financial requirements of the cooperatives.

The committee recommended that co-ops retire capital credits to emphasize the benefits of member ownership. It also emphasized the importance of maintaining financial strength in order to ensure access to capital, recommending a minimum equity level of 30 percent.

In the time since that report was completed, most cooperatives have complied with those recommendations. Analysis of the 2003 Form 7 data reported to RUS and CFC shows that the composite equity of distribution cooperatives exceeded 40 percent, and 84 percent of eligible systems were retiring capital credits.[5] Electric distribution cooperatives are now retiring more than $300 million in capital credits each year. (Additional information about trends in co-op equity and capital credits retirement levels is available online at Cooperative.com.)

Now that capital credits allocations have grown to significant dollar amounts, there are a number of reasons for taking another look at capital credits issues. For example, there have been questions about the practices of some co-ops that have accumulated significant equity but do not retire capital credits. Some co-ops face contractual, legal and regulatory challenges in retiring capital credits. Others have chosen to accumulate equity as a matter of policy.

[1] The Tennessee Valley Authority (TVA) interprets its power contracts with electric cooperatives as prohibiting the retirement of capital credits. Because of this prohibition, the information and recommendations contained in this report may not apply, or may apply differently, to electric cooperatives served by TVA. Further, because of the TVA power contract, case law in the U.S. Court of Appeals for the Sixth Circuit regarding the tax-exempt status of electric cooperatives, and the application of Internal Revenue Code (IRC) Section 501(c)(12) to mutual, as well as cooperative, organizations, the Internal Revenue Service (IRS) has accepted certain capital credits practices by TVA electric cooperatives. It is unclear whether the IRS would accept similar practices in other areas of the country.

[2] REA was the predecessor to the Rural Utilities Service (RUS).

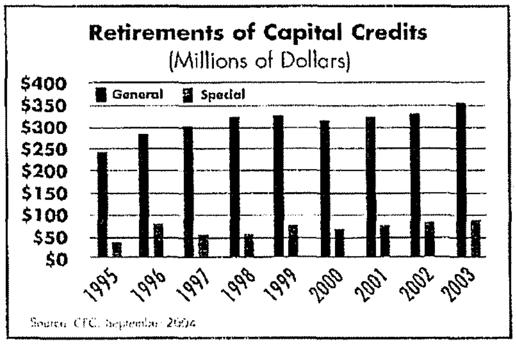
[3] *Final Report and Recommendations*, Capital Credits Study Committee, February 1976.

[4] *Capital Credits Retirement Procedures, The Report of the Capital Credits Retirement Procedures Task Force*, August 1980.

[5] The number of eligible systems does not include cooperatives served by TVA, Public Power Districts and mutual companies. As noted above, TVA has interpreted its power contracts with electric cooperatives as prohibiting the retirement of capital credits.

More and more cooperative boards are looking at their patronage capital policies and asking some very good questions, such as:

- Do current and historic policies maximize benefits to the cooperative and for its members?
- Do the co-op's practices balance the need to return capital to the members with the need to maintain the financial strength of the cooperative?



Co-ops are retiring capital credits in significant dollar amounts.

In addition, the demographics of some cooperative service territories have changed substantially since the 1970s studies. Some serve areas with rapid growth and a high rate of member turnover.* While basic capital credits tenets still apply, the practices and procedures appropriate for those co-ops may be different than those appropriate for co-ops serving stable areas with less customer turnover.

Other developments since the last studies include an increase in the use of discounting, new interest in developing permanent equity and increased awareness of alternatives to the traditional first-in, first-out (FIFO) retirement method. There also are new legal, accounting and operating issues that require attention, and many co-ops now offer diversified services.

In December 2003, the NRECA and CFC boards of directors adopted a recommendation by the NRECA issues committee to appoint a Capital Credits Task Force to conduct a new study of capital credits issues. The task force was put in place to address:

- The balance between retaining capital credits to build co-op financial strength and returning those benefits of ownership to co-op members,
- The advantages, disadvantages and legal issues associated with the various allocation and retirement methods,
- Short- and long-term trends in equity development and capital credits retirements,
- Tax and accounting considerations, and
- Legal issues arising from state and federal laws and regulations.

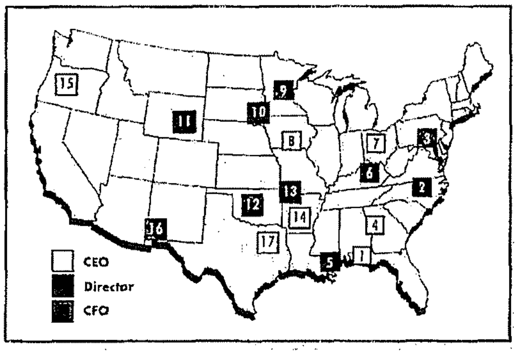
Survey Results

Seventy-eight percent of respondents to the task force survey say they retire capital credits annually, and 80 percent retired capital credits in 2003. The respondents also reported that on average, 72.8 percent of their current members received a retirement in 2003.

Source: *Survey Report*, Capital Credits Task Force March 9, 2004

* See page 65.

The 17-member task force includes seven CEOs, five CFOs and five directors from co-ops representing the diversity of the cooperative network in terms of size and geographic location. It includes representatives from generation and transmission (G&T) cooperatives and distribution cooperatives. A list of the task force members is included on page 6.



The Capital Credits Task Force represents co-ops across the nation.

1. Gene Smith Chairman
2. James Andrews
3. Joe Cole
4. Michael Whiteside
5. Charles Lopez
6. Dave Eames
7. Roger Yoder
8. John R. Smith
9. Mike Bash
10. Eunice Bartels
11. Jack Preston
12. Charles Barton
13. R. Layne Morrill
14. Gary Voigt
15. Bill Kopacz
16. Denise Barrera
17. Debbie Robinson

The task force has enlisted the assistance of legal, tax, finance and accounting experts to advise it on relevant issues. It has sought and received input from the cooperative network through several channels, including separate surveys of distribution cooperatives and G&T cooperatives to determine their practices and concerns. The distribution survey was sent to 885 cooperatives; 509, or 58 percent, replied. Of those responding, 78 percent retire capital credits annually, and 43 percent use the FIFO method.[7] Many co-ops report using a hybrid of two methods. Survey respondents said that the strengths associated with current policies for retiring capital credits include creating loyalty and good member relations, demonstrating the benefit of being a member/owner and consistency. Weaknesses cited include little benefit to new and current members, too much lag time, and the difficulty and expense of administering the program.

A survey of G&T systems was sent to 80 cooperatives; 30, or 38 percent, replied. Of those responding, 97 percent said they allocate capital credits with about 50 percent retiring on an annual basis. While results indicated that it is not a common practice for a G&T cooperative to collaborate with its distribution members on a capital credits plan, it is clear that directors and CEOs of distribution systems, serving as G&T directors, do influence the amount and timing of patronage retirements, providing some coordination of patronage allocation and retirement practices.

(Complete survey results are available online at Cooperative.com.)

The task force has produced this document with the hope that it will enable co-ops to consider a variety of successful practices and adopt an approach best suited for the unique requirements of their membership.

[7] See page 39.

Chapter 1: Capital Credits Basics

Questions for board consideration

- What are capital credits?
- How do capital credits help co-ops operate in accordance with cooperative principles?
- What are the business advantages of allocating and retiring capital credits?
- Should cooperatives convert some capital credits to permanent equity?
- What are the responsibilities of the board of directors and management regarding capital credits policies?

All business organizations need capital to operate, which is usually supplied by a combination of equity and debt. A stock company, such as an investor-owned utility, can raise equity by selling shares of stock, or ownership, in the company to the general public. Stockholders invest in the stock willingly with the expectation of earning a return on the investment through dividends and capital appreciation.

An electric cooperative generally cannot issue stock and pay dividends to the general public.[6] However, it still needs to maintain an adequate level of equity to ensure financial health and stability.

WHAT ARE CAPITAL CREDITS?

The most significant source of equity for most cooperatives is the retention of margins from the sale of products and services.[7] These margins are allocated to patrons as capital credits based on their purchases from the cooperative, or patronage.

A cooperative's capital credits practices are grounded in cooperative principles. They are also governed by:

- Federal laws and regulations,
- State laws and regulations,
- Articles of incorporation,
- Mortgage covenants and other contractual obligations,
- Bylaws, and
- Board policies.

Other factors affecting capital credits practices include financial considerations, such as the need to balance debt and equity to maintain creditworthiness, rate competitiveness, accounting practices, and the opportunity to use capital credits to build greater awareness of the values and heritage that make co-ops unique among electricity providers.

Keywords

member *Any individual or entity that is* entitled to participate in cooperative elections and vote and to share in patronage capital allocations.

patron Any individual or entity doing business with the cooperative that is entitled to share in patronage capital allocations. All members are patrons. All patrons, however, are not necessarily members. Only members are entitled to participate in cooperative elections. A cooperative also may have customers that are neither patrons entitled to share in patronage capital allocations nor members entitled to vote.

capital credits Margins credited to patrons of a cooperative based on their relative purchases from the cooperative. Capital credits are used by the cooperative as its primary equity base, then paid back to the membership as financial conditions permit. Capital credits reflect each member's ownership in the cooperative. Also called patronage capital or equity capital.

allocate capital credits To assign capital credits to members/patrons.

retire capital credits To pay capital credits to members/patrons either through cash, credit or property. Also called revolving, rotating or redeeming capital credits.

rotation period The period of time that capital credits are held by the cooperative before being returned to members. For example, a co-op retiring capital credits using the first-in, first-out (FIFO) method and a 20-year rotation period would return capital credits allocated in 1984 in 2004.

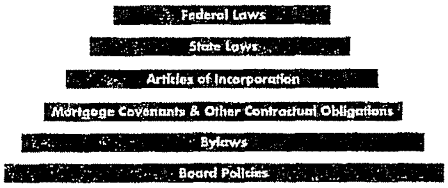
[6] A few co-ops have suggested converting capital credits to preferred stock with a dividend of up to 8 percent in order to establish a permanent pool of equity (see page 19).

[7] Other potential sources of co-op equity include items such as member fees and unallocated accumulated non-operating margins

HOW DO CAPITAL CREDITS HELP CO-OPS OPERATE IN ACCORDANCE WITH COOPERATIVE PRINCIPLES?

The International Cooperative Alliance (ICA), an association that serves all kinds of cooperatives worldwide, has identified basic values shared by all co-ops: "Cooperatives are based on the values of self-help, self-responsibility, democracy, equality, equity and solidarity. In the tradition of their founders, cooperative members believe in the ethical values of honesty, openness, social responsibility and caring for others."[iii] The ICA has adopted seven principles to guide co-ops in putting these values into practice. Adherence to these principles is one of the characteristics that distinguish cooperatives from other electricity suppliers.

The Pyramid of Authority
(Legal Authorities That Govern Capital Credits Practices)



Membership in an electric cooperative is open to anyone who is able to purchase electric service through the cooperative and is willing to accept the responsibilities of membership. Each member also is an owner of the cooperative. As owners, the members want to see that the cooperative maintains good financial health. Maintaining adequate equity is part of the board of directors' responsibility.

Member-owners control the cooperative by approving matters affecting the governance of the co-op and by electing members to serve on the board of directors. The board is accountable to the membership for the cooperative's operations and results. This keeps operations focused on meeting member needs, and it also obligates the members to elect directors who make sure the cooperative maintains fiscally sound operations.

Members have an economic stake in the cooperative. By acting together through the cooperative, members can obtain services that might otherwise not be available and achieve the advantages of economies of scale and bargaining power. They have an obligation to pay rates sufficient to meet the co-op's operating expenses and financing needs, to provide for growth and to provide margins to meet equity goals. Members are also entitled to a return of their equity investment, at some point, in proportion to their use of services from the cooperative.

Electric cooperatives implement cooperative principles by, among other things, allocating capital credits to members each year and by retiring capital credits when authorized by the board of directors as the co-op's financial situation allows. In devising a capital credits policy, it is important to remember that capital credits are an investment in the cooperative that should ideally be returned to the member on a reasonable, systematic basis.

Seven Principles Distinguish Co-ops from Other Electric Suppliers

1. **Voluntary and Open Membership** Cooperatives are voluntary organizations, open to all persons able to use their services and willing to accept the responsibilities of membership, without gender, social, racial, political or religious discrimination.

2. **Democratic Member Control** Cooperatives are democratic organizations controlled by their members who actively participate in setting their policies and making decisions. Men and women serving as elected representatives are accountable to the membership. In primary cooperatives, members have equal voting rights (one member, one vote) and cooperatives at other levels are organized in a democratic manner.

[iii] *Statement on the Cooperative Identity* adopted at the 1995 Congress and General Assembly of the International Cooperative Alliance.

3. **Member Economic Participation** Members contribute equitably to, and democratically control, the capital of their cooperative. At least part of that capital is usually the common property of the cooperative. The members usually receive limited compensation, if any, on capital subscribed as a condition of membership. Members allocate surpluses for any or all of the following purposes: developing the cooperative, possibly by setting up reserves, part of which at least would be indivisible; benefiting members in proportion to their transactions with the cooperative; and supporting other activities approved by the membership.

4. **Autonomy and Independence** Cooperatives are autonomous, self-help organizations controlled by their members. If they enter into agreements with other organizations, including governments, or raise capital from external sources, they do so on terms that ensure democratic control by their members and maintain their cooperative autonomy.

5. **Education, Training and Information** Cooperatives provide education and training for their members, elected representatives, managers and employees so they can contribute effectively to the development of their cooperatives. They inform the general public—particularly young people and opinion leaders—about the nature and benefits of cooperation.

6. **Cooperation Among Cooperatives** Cooperatives serve their members most effectively and strengthen the cooperative movement by working together through local, regional, national and international structures.

7. **Concern for Community** While focusing on member needs, cooperatives work for the sustainable development of their communities through policies accepted by their members.

WHAT ARE THE BUSINESS ADVANTAGES OF ALLOCATING AND RETIRING CAPITAL CREDITS?

Research shows that most consumers judge a cooperative on the basis of its quality of service and reasonableness of rates. A sound capital credits policy can help a cooperative improve member perception of its performance in these areas and distinguish it from other service providers. Research shows that returning capital credits to consumers contributes significantly to their perception of receiving good value as well as increasing their sense of membership. It can help a co-op connect with members in a way that contributes to satisfaction and customer loyalty.

Reduced cost of doing business Capital credit allocations help a cooperative qualify for cooperative status under federal income tax law, thus eliminating or reducing income tax liabilities and the associated costs.

Reduced net cost of electricity for members Capital credit retirements offset a portion of the costs consumers pay through electric rates.

Member education and public relations benefits A co-op member who receives a capital credits retirement receives a tangible reminder of the values and heritage that make cooperatives unique among electric providers.

Reduced vulnerability to takeover and sellout attempts Members who realize tangible benefits from cooperative ownership are more likely to resist takeover attempts, while failure to retire capital credits may provide an incentive for sellout.

Learn from Experience
Boone EC Educates the Educated

In the bustling university town of Columbia, Missouri, Boone Electric Cooperative knows it needs to think out of the box when it comes to educating its members about the cooperative way of doing business.

Home to three major universities and colleges, including University of Missouri's main campus, this 27,000-meter co-op disconnects and reconnects about 8,000 meters every year. "We have an extremely high volume of transient members," says Boone EC General Manager and CEO Roger Clark. "In the short time that many of them are here, it is a daily challenge to find creative ways of helping them see the benefits of cooperative membership."

One way Boone tackles this challenge is by using a LIFO/FIFO hybrid to retire its capital credits. "Last year we had such a good year—primarily weather driven—that we were able to retire $3 million," Clark says. "We returned $2 million in current-year margins and $1 million in old margins. Since margins were so high this year, we decided to retire a higher percentage than usual—which is typically a 50/50 split."

Boone mails notices to its members at the end of March letting them know their portion of the capital credits allocation. In mid-December, just before the holidays, they send capital credits checks to qualifying members. "We know it costs more to send checks, but we believe the money is well spent. These checks are the best way for us to tell the cooperative story," Clark says. "Many times we'll get calls from members asking why they received a check—there is no better opportunity for us to explain what makes us different and what it means to them to be a member." He said one member even sent a special thank-you note to the co-op for her capital credits check. "This member told us that she wouldn't have been able to buy Christmas presents for her children without it."

When it comes to reviewing its capital credits policy, Boone says it's an ongoing process. "Our board and staff use the three-legged-stool approach—we look at where we want rates to be, where we want our equity and financial ratios to be, and how we can best meet our capital credits retirement goal for the year," Clark says. "We do this planning with the help of our 10-year financial forecast. It helps us to keep a healthy balance and ease into where we want to be down the road."

Boone is making big strides in a big college town. "Last year, for the first time, we ran an ad about our capital credits payout in the *Columbia Daily Tribune*. This got the attention of members and non-members alike," Clark says. "Customers of the local municipal utility wanted to know why they weren't getting checks from their utility!"

It's all about education at this university town co-op.

SHOULD COOPERATIVES CONVERT SOME CAPITAL CREDITS TO PERMANENT EQUITY?

One emerging issue is whether there is a need for cooperatives to create a pool of permanent equity not allocated to the members as capital credits. In some cases, permanent equity results from a business decision made for other reasons. For example, when a cooperative retires capital credits to an estate at a discount, the cooperative assumes ownership of the difference between the total allocation and the amount retired.[11] The decision to make that retirement was likely based on the mutual benefits to the cooperative and the member's estate. In another example, a cooperative may choose to not allocate an extraordinary gain for which it receives no cash. The decision is likely based on cash requirements rather than a desire to create additional equity.

Some cooperatives, however, have considered accruing permanent equity as a matter of policy. Whether to do so is a fundamental strategic decision. It represents a basic change in interpretation of cooperative principles. It also may require changes in allocation and retirement decisions.

[11] In some cases, the IRS has allowed cooperatives to reallocate the difference to remaining members of the cooperative. In other cases, the IRS has denied this approach.

There are at least three potential sources for funding permanent equity:

- Non-patronage-sourced margins,[12]
- The amounts remaining after discounted special retirements,[13] and
- The amounts remaining after discounted general retirements.[14]

If a co-op chooses to develop permanent equity, its capital credits policies will determine the level that can be reasonably attained and how quickly it will be reached.

Those who favor developing permanent equity say that it:

- Provides permanent reserves,
- Allows the co-op to rotate operating margins more quickly, and
- Improves a co-op's credit profile when implemented in conjunction with a sound equity management plan.

In addition, permanent equity may provide capital for investing in diversified goods or services to meet member and community needs—when a cooperative may lawfully do so. Further, if an electric cooperative loses its federal income tax exemption, then retaining non-patronage-sourced, non-operating margins prevents the cooperative from being in the unenviable position of paying tax on these margins and having allocated them.

Those who oppose creating permanent equity say that it is not necessary because the same goals can be achieved through other means. In addition, adopting the practices that create permanent equity may appear to consumers to be unfair and contrary to cooperative principles.

Co-ops can manage their balance sheets without permanent equity because capital credits retirements are discretionary. The board determines when, how and how much to retire. If a co-op has a low level of equity overall, some say accumulating permanent equity can be an option for reaching an adequate equity level in a reasonable time frame. With an appropriate equity management planning process, however, the board can achieve the same thing by adjusting its capital credits retirement schedule. If a co-op already has a high level of equity, it probably would not benefit from developing permanent equity. If funds are needed for a special purpose, the co-op can establish a reserve for that purpose.[15]

In considering the issues associated with permanent equity, it is important to remember that a cooperative's equity does not belong to the cooperative. It belongs to its members. To the degree that an equity contribution becomes permanent, it now belongs to all members instead of an individual member. By creating permanent equity, the co-op may be creating an incentive for sellout as the members may perceive that their best option for getting their money back is to sell the cooperative.

Recommendation
Permanent Equity

The development of permanent equity should not be a goal of a cooperative's capital credits policy. Any advantages of permanent equity, such as building a cooperative's equity level or developing reserves, can be achieved in more direct ways that do not involve the same tax, takeover or other risks inherent in a policy of permanent equity.

[12] See page 24
[13] See page 47
[14] See page 47
[15] See page 35

Some electric co-ops have proposed converting capital credits to preferred stock bearing a dividend of up to 8 percent as a means of creating permanent equity. IRS Publication 557[16] states that cooperatives that are tax-exempt under Section 501(c)(12) may not issue stock that pays a dividend. The IRS has, however, acknowledged in an information letter that electric co-ops may have preferred stock but has refused to issue advanced rulings approving any particular terms and conditions for such an issuance. Whether the amount of stock issued would violate the subordination of capital principle would have to be determined on audit. In addition, many state electric cooperative acts require co-ops to operate on a non-profit basis, which in most cases precludes paying dividends on shares of stock issued to members. From a financial perspective, preferred stock is an expensive source of capital, particularly compared to debt and internally generated funds.

Depending on the source of the permanent equity, the co-op also may incur significant costs in terms of time and money in obtaining the legal and IRS rulings necessary to establish permanent equity. Creating permanent equity through discounting also may create taxable income. A cooperative considering this approach should consult its tax experts regarding approaches that will avoid creating taxable income.

In considering a policy to create permanent equity, the board must compare the potential costs and benefits with similar results that can be obtained through other means. There may be occasions when a cooperative has a unique need or opportunity that results in permanent equity, for example, as a result of retaining unclaimed capital credits; not allocating non-patronage-sourced, non-operating income; or discounting capital credits retirements. This approach may have value, but, depending on the source of permanent equity, the process may be complicated by state enabling statutes and potential federal tax liabilities. Any system contemplating the retention of permanent capital should seek expert advice in developing and implementing such a plan.

Directors Should Carefully Consider the Issues Before Adopting a Policy to Develop Permanent Equity	
Arguments in Favor of Permanent Equity	**Arguments Against Permanent Equity**
• Provides permanent reserves • May allow co-op to rotate remaining patronage capital more quickly • May improve credit profile • May reduce requirements for keeping records • May be best alternative for treating extraordinary gains • May provide capital for diversified goods and services • Avoids allocation and taxation of non-patronage-sourced, non-operating margins	• Requires fundamental change in interpretation of cooperative philosophy and may require a change in bylaws • May appear to members to be inconsistent with cooperative principles • Could result in non-member taxable income • Costs more than other sources of capital • May create incentive for sellout • May achieve same results more easily and less expensively through other means

WHAT ARE THE RESPONSIBILITIES OF THE BOARD OF DIRECTORS AND MANAGEMENT REGARDING CAPITAL CREDIT POLICIES?

A co-op's board of directors and management have a responsibility to establish and periodically review the co-op's capital credits policy. The board's role is strategic in scope. It establishes a vision and basic principles for the cooperative. As the elected representatives of the members of the cooperative, directors must also understand the capital credits policy and be able to explain to members why it was adopted and how it works. Management and staff are responsible for developing and implementing procedures that will achieve the board's vision.

[16] IRS Publication 557, *Tax-Exempt Status for Your Organization* (Rev. May 2003)

The process for establishing a capital credits policy is complex, and the board must make decisions about many issues, including:

- What funds will be allocated to members,
- How funds will be allocated,
- How members will be notified of their allocations,
- What amount of capital credits to retire each year,
- Which retirement method to use,
- Whether to make special retirements,
- Whether to discount any retirements and if so, the discount rate to use, and
- What approach to retiring capital credits will maximize the value for the co-op and its members.

In making these decisions, the board should be guided by the answers to two fundamental questions:

- What are the co-op's strategic goals for its capital credits policy?
- What techniques for allocating capital credits, retiring capital credits, refunding capital credits to members and communicating with members about capital credits will be most effective in helping the co-op achieve these goals?

The board must achieve all this while complying with applicable laws, regulations and the co-op's own bylaws. In some cases, a legal authority dictates the approach that must be taken. In other cases, the board has discretion to choose among alternatives, and the co-op's goals will determine the approach. These decisions are interrelated in that a decision on one issue may have consequences for another. Allocation, retirement, compliance and communication issues are discussed in greater detail in other sections of this report.

It is also important that the policy be supported by sound financial management. Each co-op should have an equity management plan that allows it to balance equity and debt effectively to meet a variety of financial needs and criteria, including:

- Maintaining financial strength,
- Meeting mortgage requirements,
- Funding new construction,
- Retiring capital credits, and
- Ensuring fairness across generations.

The information provided in this report can help co-ops understand the legal, accounting and financial issues affecting capital credits policies so that these goals are met. It is also important that a cooperative seek the advice of its own legal, accounting and tax consultants when reviewing and formulating policies. In the end, however, it is up to the board to evaluate information from all sources and make an independent decision on capital credits policies.

Recommendation
A Board-Approved Policy

Every electric cooperative should have a policy for annually allocating capital credits and, subject to the board of directors' discretion and the cooperative's financial condition, annually retiring capital credits.

Chapter 2: Allocating Capital Credits

Questions for board consideration

- What funds will the co-op allocate to members as capital credits?
- Should the co-op allocate non-operating margins?
- Should the co-op allocate losses?
- How should the co-op treat capital credits from affiliated organizations?
- On what basis should co-ops allocate capital credits?
- Can the co-op require a contractual forfeiture of rights to capital credits from some members?
- How should a co-op that offers multiple services allocate capital credits?
- Is the co-op keeping adequate records of each member's rights to capital credits?
- Is the co-op providing adequate notification to members of their capital credits allocations?
- When does a member's right to capital credits vest?

To qualify for federal tax-exempt status under Internal Revenue Code (IRC) Section 501(c)(12),[17] a co-op generally must allocate capital credits to patrons each year and maintain records sufficient to reflect the equity of each member in the assets of the cooperative. State statutes and regulations and the cooperative's bylaws may impose additional allocation requirements and restrictions.

Section 501(c)(12) requires cooperatives to operate at cost with respect to its exempt purposes. For most electric distribution cooperatives, the exempt purpose will be providing electricity to patrons, unless the co-op engages in one or more "like activities" on a cooperative basis. That means that any excess of operating revenues collected over operating expenses from the provision of electricity must be allocated to patrons as capital credits, based on their participation, and ultimately returned to patrons.[18] Additionally, the allocation of patronage capital must be subject to a pre-existing obligation and must be fair and equitable on the basis of patronage. While cooperatives may retain capital credits for a period of time to meet equity needs, Section 501(c)(12) generally requires a cooperative to allocate and assign capital credits to patrons each year and to maintain records of such allocations. Capital credits should be accounted for in a way that reflects the rights and interests of members in the net savings of the cooperative. These rights and interests must be protected and not forfeited.

It is important to note that the allocation reflects members' ownership, which will be redeemed at a future date determined by the board.[19]

Keywords

operating margins Revenues derived from the co-op's marketing, purchasing or providing electric and other qualifying tax-exempt services, as well as other revenues derived from utilization of the co-op's electric and other plant assets, less the expenses incurred to supply those services.

non-operating margins Income (revenues less related expenses) derived from non-electric products, services and/or investments.

patronage-sourced margins Revenues resulting from transactions that directly facilitate accomplishing the co-op's marketing, purchasing or service activities, less the expenses incurred to generate those revenues.

non-patronage-sourced margins Revenues resulting from activities that are not substantially related to the accomplishment of the co-op's marketing, purchasing or service activities less the expenses incurred to generate those revenues.

(Note: Accountants use the term margins and income interchangeably. Cooperatives tend to prefer the use of margin, as the word income can suggest profit.)

Survey Results

The task force survey found that some co-ops choose not to allocate some margins.

Item	Percent Not Allocating
Subsidiary or diversification accrued non-operating margins	30%
Non-cash non-operating margins	22%
Unbilled revenue or other similar accrued operating margins	21%
Inactive accounts with relatively small patronage	10%

Source: *Survey Report,* Capital Credits Task Force March 9, 2004

[17] When this report refers to requirements under 501(c)(12), it is referring to case law interpreting requirements for co-ops organized under 501(c)(12).
[18] TVA interprets its power contracts with electric cooperatives as prohibiting the retirement of capital credits. Because of the TVA power contract, case law in the U.S. Court of Appeals for the Sixth Circuit regarding the tax-exempt status of electric cooperatives and the application of IRC 501(c)(12) to mutual, as well as cooperative, organizations, the IRS has accepted certain capital credits practices by electric cooperatives served by TVA. It is unclear whether the IRS would accept similar practices in other areas of the country.
[19] For more information about the nature of capital credits, see page 16. For more information about the retirement of capital credits, see page 34.

Uniform System of Accounts Versus Tax Regulation

The RUS Uniform System of Accounts and the FERC Uniform System of Accounts assign specific accounts for operating and non-operating margins. Cooperatives that are not RUS borrowers and are not subject to FERC jurisdiction prepare financial statements in accordance with generally accepted accounting principles, or GAAP; the income accounts are similar to those of the RUS and FERC systems. Unfortunately, tax regulations are based on patronage-sourced margins and non-patronage-sourced margins. The definitions of patronage- and non-patronage-sourced margins have been determined by federal courts. Operating margins are generally considered patronage-sourced; however, non-operating margins may be either patronage-sourced or non-patronage-sourced income. Some examples as determined by court decisions include:

Patronage-sourced Income	Non-patronage-sourced Income
• Operating margins, except for operating margins related to the sale of electric energy to non-member, non-patrons • Patronage refunds from other cooperatives • Interest income from short-term investment of seasonal surplus cash and income from temporary excess warehouse space • Interest income from loans to cooperative's chief suppliers to ensure supplies for operations • Interest income from short-term capital loans to a regional supply cooperative if such loans are made from patronage proceeds temporarily in cooperative's hands	• Non-operating margins from subsidiaries • Income from investments in securities • Interest income from money management of excess operating funds • Interest income from short-term placement of funds not immediately required for use • Income from business done with or for a non-member or non-patron by a non-exempt cooperative

WHAT FUNDS WILL THE CO-OP ALLOCATE TO MEMBERS AS CAPITAL CREDITS?

IRS audit guidelines regarding cooperative principles require a cooperative to allocate operating margins. Tax laws, however, allow taxable cooperatives a deduction for all patronage-sourced income. Allocating all patronage-sourced income helps to minimize tax liabilities for taxable cooperatives. It is a prudent practice for tax-exempt cooperatives to allocate patronage-sourced income as well, in case the co-op is found to be taxable for a given year at a later date. For most co-ops the major source of patronage-sourced income will be operating margins.

Depending on state laws, the co-op's bylaws and other regulations, the board of directors may have the discretion to choose whether to allocate non-patronage-sourced income, such as non-operating income. Members do not receive a vested interest in any allocations until the capital credits are retired or the co-op is liquidated.[20]

[20] See page 35.

Learn from Experience
When Not Allocating Makes Sense

Many co-ops follow the practice of allocating all margins as capital credits. Some state laws, however, permit co-ops to retain non-operating margins. While many co-ops choose to allocate non-operating margins as a matter of philosophy, there may be circumstances when not allocating non-operating margins makes sense.

For example, in 2001, an exchange of subsidiary assets for an equity interest in a new business created an extraordinary accrued (non-cash) non-operating margin for Adams Electric Cooperative, Gettysburg, Pennsylvania. The co-op did not allocate the paper gain because it was uncertain as to whether it would ever receive any cash receipts. Instead, it retained it as a reserve to offset potential future non-operating margin losses, should they occur, which could otherwise diminish electric operating margin allocations in the year in which they occurred. The co-op does allocate cash received from the investment as capital credits.

SHOULD THE CO-OP ALLOCATE NON-OPERATING MARGINS?

Some co-ops have the option of not allocating non-operating margins. However, many cooperatives do so as a matter of philosophy and practicality.

One argument in favor of allocating non-operating margins is that members assume the risk of activities that produce non-operating margins. The risk may be significant in some cases, for example a non-electric business subsidiary. If there are losses, the members may have to pay higher rates to cover them. Members share in any disadvantages from these activities. Some boards, therefore, believe that members should also share in any margins or gains.

Another viewpoint is that cooperatives should not allocate non-operating margins in order to create permanent equity.[21]

There also may be occasions when it just makes sense to avoid allocating a non-operating margin, such as in the case of an extraordinary gain that does not result in cash to the cooperative. Additionally, the allocation and subsequent retirement of non-operating, non-patronage margins by a taxable cooperative may result in a taxable dividend to the patrons and may result in additional reporting by the non-exempt cooperative to the patrons.

SHOULD THE COOPERATIVE ALLOCATE LOSSES?

Unfortunately, sometimes a board must deal with losses. Most boards are extremely reluctant to allocate losses. In addition, RUS regulations[22] prohibit distribution borrowers from allocating losses and require instead that systems accumulate and offset losses against future non-operating margins. RUS permits G&T systems to allocate losses, though the typical G&T practice is to offset losses against future gains.

Co-ops that are not RUS borrowers should have the flexibility to assign losses if that is the best option. For example, a co-op could earn positive margins on its core electric business and suffer ongoing losses in a subsidiary. If significant, the scale of the losses could prohibit the cooperative from ever retiring the capital credits allocated from electric operations. This could raise tax concerns about whether the co-op is really operating at cost in its electric business.

If a cooperative assigns a loss as a "negative allocation" for the specific year in question, then the retirement method chosen should consider this negative allocation when retiring capital credits so that, over time, the net amount of capital credits allocated to the patron is retired. The cooperative also must address how to handle any losses assigned to a patron that becomes inactive after the year of the loss and has a negative capital credits balance as a result of assignment of the loss. The ability to assign operating losses to members may require a bylaw amendment, as some bylaws require operating and non-operating losses to be offset against non-operating income.

[21] See page 19.
[22] 7 CFR 1767.41 *Code of Federal Regulations*, Accounting Methods and Procedures Required of All RUS borrowers.

Survey Results

Sixty-seven percent of respondents to the task force survey say they allocate G&T capital credits separately from operating margins, and 30 percent say they retire capital credits derived from a G&T allocation on a different basis than other allocated margins.

Source: *Survey Report*, Capital Credits Task Force March 9, 2004

Other options for dealing with losses include:

- Canceling prior-year capital credits of members generating the loss,
- Carrying the loss forward to offset future allocations, and
- Offsetting an unallocated reserve or similar amount, such as capital not assignable to the patrons prior to the dissolution of the cooperative.

The implementation of these options also may require a bylaw amendment. Options may be used in various combinations if the amended bylaws provide this flexibility. For example, to the extent that the loss exceeds the outstanding capital credits allocated in a prior year for a loss-year patron, the board may approve carrying this excess loss forward to offset future allocations or offset such excess against unallocated reserves or similar amounts.

The goal is to handle losses in a way that ensures that the capital credits allocated and retired represent overall margins generated by patrons purchasing electricity in proportion to the business done.

HOW SHOULD THE CO-OP TREAT CAPITAL CREDITS FROM AFFILIATED ORGANIZATIONS?

Many cooperatives receive capital credits allocations through membership in an affiliated organization, such as a G&T cooperative, a materials supply cooperative or CFC. These capital credits generally constitute patronage-sourced income even though they do not represent operating margins. It is prudent for co-ops to allocate capital credits received from affiliated organizations to their own members for tax purposes.

A cooperative has the option of developing a separate policy for allocating and retiring capital credits from affiliated organizations. It may choose a different allocation method and a different rotation period for these capital credits amounts. Some cooperatives believe a separate allocation is particularly desirable when the amount is likely to be sizeable, such as an allocation from a G&T. A separate allocation also may be desirable if the affiliated organization has a different rotation cycle from the receiving organization or if it is unlikely that the co-op will ever receive a cash retirement.

Other cooperatives prefer not to make separate allocations of capital credits received from affiliated organizations, arguing that capital credits allocations are not different from other sources of margins and that distribution systems should allocate and retire capital credits to their members without regard to the source of the margins.

Learn from Experience
Defining Fairness at Union REC

For co-ops with extremely large commercial and industrial loads, it can be challenging to ensure that these unique members—along with all other types of members—are treated fairly and equitably. Union REC in Marysville, Ohio, is faced with this issue every day in a big way—not only when it comes to setting rates, but also when it comes to retiring capital credits.

In addition to serving about 7,300 residential and commercial members in Union County, Ohio, Union REC serves the Honda of America Mfg., Inc., automobile and motorcycle facility as well as the Honda Research and Development facility. Honda has been a member of Union REC since 1979. The Honda facility—which produces 1,800 cars and 400 motorcycles a day—has brought a wealth of jobs to the central Ohio area and has contributed significantly to the overall economic health of the region. The combined automobile and motorcycle facility accounts for 69 percent of Union REC's total annual kwh sales.

"Honda is very important to the economic success of Union REC, Union County and the central Ohio area," says Union REC President/CEO Roger Yoder. "It is important to our community that we provide top-notch electric services to this important member. In our dealings with them, we must be professional, competitive, and ethical."

Union offers Honda a completely unbundled, cost-of-service based rate that includes a separate line item on their monthly invoice called "Contribution to Operating Cost," which represents Honda's contribution to margins. Union's board of trustees and staff believe that this rate approach—which provides Honda with a competitive rate while keeping margins as low as possible—is an equitable and fair way for the co-op to treat Honda and its other members. "The rate structure basically fixes the amount of margins generated by Honda and provides us with an easy method to identify and allocate Honda's margins," Yoder says. "When the board of trustees approved retiring all of 1988 capital credits and a portion of 2001 capital credits last year, Honda's amount was significant. The retirement is refunded on their invoice over a 12-month period. This method is mutually advantageous to Honda, the co-op and our members."

Previously, the margin was a product of a markup on wholesale energy and demand. "As Honda's load would increase, the margins would increase potentially to a disproportionate level compared to our other classes of members," Yoder says. "Using the fixed margin rate, the margins are not based on energy or demand charges. Therefore, kwh sales or revenues are not used to allocate capital credits to Honda, which would create an unfair allocation of capital credits compared to the other classes of members."

Union's capital credits policy is based on the premise of fairness and consistency. "We feel the capital credits process is a basic fundamental principal of our cooperative business structure and that it is important in distinguishing us from other utilities," Yoder says. "Our equity management and cost-of-service studies include generating sufficient revenues to fairly and equitably plan for the rotation of capital credits to all members."

ON WHAT BASIS SHOULD CO-OPS ALLOCATE CAPITAL CREDITS?

Co-ops may allocate capital credits on a variety of bases, provided that the basis is fair and equitable to patrons, including:

- Value (dollar amount of purchases),
- Quantity (kilowatt hours or other measure), or
- Cost of service (contribution to margins).

The most frequently used approach is to allocate capital credits based on the value of purchases from the co-op.

Recommendation
Contractual Forfeiture

Electric cooperatives should not enter contracts that require members to forfeit the right to capital credits in return for other considerations, such as reduced rates.

A cooperative may use different allocation methods for different customer classes, but the same method must be used for all customers within a class. As a practical matter, it would be burdensome for most cooperatives to allocate on a cost-of-service basis to individuals in the residential class, but it might be the best option for large commercial customers.

The board should carefully consider various options before adopting an allocation basis. The IRS expects the allocation method to be fair and equitable and to be consistently applied from year to year. While it is possible to change allocation methods occasionally, the board should have a valid business purpose, other than tax avoidance, for doing so.

CAN THE CO-OP REQUIRE A CONTRACTUAL FORFEITURE OF RIGHTS TO CAPITAL CREDITS FROM SOME MEMBERS?

Some cooperatives have considered adopting policies that allow certain members, such as large commercial or industrial accounts, to contractually forfeit capital credits in exchange for rate reductions. Some have also considered bylaw changes that deny capital credits to certain member groups or classes of members.

The goal of such practices is usually related to economic development. Large customers bring value to the community through jobs, taxes and other contributions. Co-ops justify special rates and practices as an important part of the effort to keep rates low in order to keep employers in the community, something that benefits all members, and to avoid the disruption and imbalance that can occur with large patronage capital allocations and retirements.

Contracts that deny capital credits to any members or class of members are questionable from a tax perspective and should be avoided. Under IRC Section 501(c)(12), in order to qualify as a member of the cooperative, a customer must have:

- A right to participate in management, and
- A right to share in capital credits.

If a large customer relinquishes the right to capital credits, then it is no longer considered to be a member of the cooperative, and income from the customer could have serious implications for the co-op's ability to comply with the 85-percent member income requirement of Section 501(c)(12). The IRS also could assert that the company is not operating in a cooperative manner. Asking a member to forego capital credits also is contrary to the provisions of RUS Bulletin 102-1, which says, "No patron should be asked by contract or otherwise to waive his capital credits." Additionally, Revenue Ruling 72-36[15] provides that if, under the bylaws, a member's rights and interest have been forfeited, then the organization has not operated on a mutual or cooperative basis and is, therefore, not exempt.

[15] The complete text of Revenue Ruling 72-36, 1972-1 C.B. 151 is shown on page 58.

Learn from Experience
Glacier Explores Procedures for Multiple Services

Due to changing competitive conditions in the late 1990s, Glacier Electric Cooperative, Inc., Cut Bank, Montana, began exploring opportunities to provide additional services, such as natural gas, propane, home security, Internet communications and satellite television services. The co-op's plan was to establish a different class of membership for each new service. The members of each class would share in capital credits based on the margins earned by that class and purchases made by the member under that class of service.

In January 1999, Glacier received a private letter ruling from the IRS accepting Glacier's plan for forming three operating units—an electric division for electricity, a gas division for propane and natural gas, and a communications division for satellite television, home security and Internet communications services. The ruling also accepted Glacier's plan to establish separate classes of membership, based on the services purchased from the cooperative. In addition, the ruling found that the proposed natural gas, home security, Internet and satellite services would be considered "like activities" for the purposes of the 85 percent test. A subsequent ruling qualified propane as a "like activity."

The cooperative amended its bylaws to establish four different customer classes. For a time, Glacier did provide wire Internet service to one class of members. This activity never generated any margins to distribute to the "Class D" members of the cooperative. It was decided, however, not to pursue offering other services directly to members at this time. (Glacier has subsequently invested in a company that offers Internet services, but the customers of this for-profit company are not Glacier members.) "We have been very cautious about how we proceeded," General Manager Jasen Bronec said. "At this point we have not exercised the option to do some of the things we could do."

The letter does, however, provide insight into how the IRS might view other cooperatives considering similar actions. (A copy of the ruling is available online at Cooperative.com.)

One way to achieve the same goal and comply with legal requirements for capital credits is to establish a separate customer class for target customers. The co-op can then adopt a rate for that class that generates little or no margin and allocate capital credits based on customer-specific margins. To be defensible, the rate should be based on a cost-of-service study.

HOW SHOULD A CO-OP THAT OFFERS MULTIPLE SERVICES ALLOCATE CAPITAL CREDITS?

According to a Power Online survey of cooperative diversification activities in 2003, 93.5 percent of distribution cooperatives responding offer, or own businesses that offer, one or more services in addition to basic electric energy.[21] Some of these services are related to electric services and offered at no charge while others are not. In some cases, the services are offered on a for-profit basis. If a co-op provides services in addition to electricity, it is important to consider the ramifications for capital credits policies.

[21] *Power Online Diversified Services Survey, 2003.*

Recommendation
Member Notification

Cooperatives should notify members in writing of the dollar amount of annual capital credits allocations.

Cooperatives should be aware that the Section 501(c)(12) requirement to operate at cost demands that co-ops account separately for the costs and expenses associated with each service provided in order to avoid cross-subsidization of services. Cross-subsidization also may raise issues with respect to the state public service commission requirements, unrelated business income taxes (UBIT) and unfair competition. It is important that the board adopt a policy that is fair, equitable and consistently applied from year to year.

Accounting for capital credits for multiple services offered on a cooperative basis can impose a substantial administrative burden on the co-op. In at least one private letter ruling, issued to Glacier Electric Cooperative, Cut Bank, Montana, in 1999, the IRS allowed a co-op to combine similar services into one allocation pool, provided that:

- Patrons of one service are also patrons of the other services in the pool;
- The co-op's articles of incorporation, bylaws or written policies specify the composition of the pool and how capital credits are to be allocated;
- The co-op notifies the members of each pool of the risks and benefits of combining the services into one pool;
- A majority of the co-op's members agree to the pool; and
- Members periodically approve the pooling agreement.[25]

For example, an electric co-op that offers telecom services might be able to combine local, long distance and Internet service in one pool for allocation purposes. It would probably not be able to combine electric and telecom services in one pool.

The co-op may adopt different retirement methods and cycles for different allocation pools. Additionally, losses from an allocation pool would be handled in accordance with the methods provided in the bylaws and board policies. The method would be applied to the allocation pool with the loss.

IS THE CO-OP KEEPING ADEQUATE RECORDS OF EACH MEMBER'S RIGHTS TO CAPITAL CREDITS?

A co-op must keep adequate records of each member's rights and interests in the cooperative's assets. In addition to capital credits balances, the records should include a history of patronage in order to allocate gains on appreciated assets and to distribute any assets (i.e. net savings of an organization) remaining after liabilities are paid if the cooperative is dissolved. A co-op cannot terminate a member's rights and interests if the member moves or otherwise terminates membership, so the co-op must maintain capital credits information and contact information if possible for former members. The co-op can shift some of the burden to

[25] Michael Seto and Cheryl Chasin, *General Survey of IRC 501(c)(12) Cooperatives and Examination of Current Issues*, which is available on Cooperative.com.

departing members by asking that they notify the co-op of future address changes. It can also be argued that there is a standard of reasonableness and that maintaining records for a lengthy period of time, such as 20 years, is adequate. Whether this argument is acceptable to the IRS and other authorities is uncertain.

Maintaining these records and keeping track of former customers can be costly and burdensome, particularly for co-ops operating in service territories with high rates of customer turnover.

The United States Postal Service provides a variety of services designed to assist users in tracking customer address changes, including the National Change of Address program.[26]

Individual states may impose specific requirements for keeping records and for publishing public notices of capital credits in unclaimed or escheat situations.

IS THE CO-OP PROVIDING ADEQUATE NOTIFICATION TO MEMBERS OF THEIR CAPITAL CREDITS ALLOCATIONS?

Another decision the board must make is whether to give members an annual written notice of capital credits allocations, and if so, what type of notice to provide. There are no requirements under Section 501(c)(12) for an exempt co-op to notify patrons of capital credits allocations, although most choose to do so.

A taxable or nonexempt cooperative, one that fails the 85-percent test, is required to give each member a written notice of the specific dollar amount within 8 1/2 months from the end of the co-op's tax year in order to claim a patronage dividend exclusion against its patronage-sourced margins. Acceptable notification methods include:

- U.S. mail,
- Message on bill, and
- Message associated with electronic bill payment.

The method chosen should take into account the privacy issues associated with communicating financial information.

If a co-op has multiple allocations, for example, capital credits from its own operations and a separate allocation from an affiliated organization, it has the option of providing a combined allocation notice with separate line items for separate allocations or issuing a separate notice for each allocation. A more general notification method, such as including the allocation formula on bills, may be insufficient to allow a taxable co-op to claim a patronage dividend exclusion.

Survey Results

Seventy-seven percent of respondents to the task force survey say they notify patrons annually of the dollar amount of their capital credits allocations.

Source: *Survey Report*, Capital Credits Task Force, March 9, 2004

[26] More information about these services is available through the Postal Service Web site, www.usps.com

Keyword

vest To confer ownership of property upon a person, to invest a person with full title to property or to give a person an immediate, fixed right of present or future enjoyment

There are strong arguments in favor of exempt co-ops notifying members of their patronage capital allocations, particularly systems that are close to failing the 85-percent test. If an IRS audit later finds the co-op to be taxable for a particular year and the co-op has failed to provide the proper notification, then the co-op will not be able to exclude capital credits from margins in computing its tax liability. Regardless of the co-op's situation with regard to the 85-percent test, notification provides an excellent opportunity to communicate with members regarding cooperative values while providing a tangible demonstration of the value of cooperative membership. Not sharing information with members about the degree of their economic participation is missing an opportunity.

WHEN DOES A MEMBER'S RIGHT TO CAPITAL CREDITS VEST?

A key legal issue associated with capital credits is the determination of when a member's rights to the payment of capital credits vests—upon allocation or retirement. Whatever other provisions they contain, the bylaws of most electric cooperatives say that the co-op can only retire capital credits if the board of directors determines that the retirement will not impair or adversely affect the cooperative's financial position. Because of this required board determination, the majority of court cases addressing this issue have held that a cooperative member's right to the payment of capital credits vests upon retirement, not allocation. Thus the member has no vested right until the board takes formal action to retire capital credits.

This is an important distinction because it affects the rights and obligations of both the co-op and the member under federal tax law, federal bankruptcy law and RUS regulations, as well as state contract, property and corporate law.[27]

[27] For more information about legal issues related to vesting, please see Section D. Vesting of Capital Credits in *Legal Issues Associated with Capital Credits*, available online at Cooperative.com.

Chapter 3: Retiring Capital Credits

Questions for board consideration

- Why should a cooperative retire capital credits?
- What amount of capital credits should the co-op retire?
- How do co-ops fund capital credits retirements?
- What method of retiring capital credits best meets the co-op's strategic goals?
- Should the board authorize special retirements?
- Should the co-op apply discounts to early retirements?
- How might a security interest in capital credits affect the co-op?
- How might the bankruptcy of a member affect the co-op?
- What other retirement issues should the board address?
- Can the co-op use unclaimed capital credits to add value for members?

While the legal requirements for allocating capital credits are quite specific, the requirements for retirements are more flexible. Questions such as when to retire, how much to retire and what method to use can be complex and difficult to answer. The answers are affected by the co-op's financial and competitive situation, the demographics of its membership and its goals for capital credits.

WHY SHOULD A COOPERATIVE RETIRE CAPITAL CREDITS?

There are both good business and legal reasons for retiring capital credits. The third cooperative principle establishes that members contribute capital equitably to the operation of the cooperative. The funds invested in the cooperative do not earn dividends or other financial remuneration. Retiring capital credits is a way of ensuring that each generation of members pays its own way by providing its own equity.

Retiring capital credits provides tangible evidence of members' ownership in the cooperative. It provides a unique opportunity to demonstrate the difference between cooperatives and other forms of business organization. It also helps solidify member loyalty by demonstrating the value of membership in the cooperative. Failure to retire capital credits can have a negative impact on public relations and even lead to litigation or a hostile takeover if unhappy members try to recover their investment in the cooperative.

There also are legal reasons to retire capital credits in order to preserve a cooperative's status under the tax laws, but it is necessary for the board, along with its advisers, to interpret the criteria. The IRS does not specifically define the conditions and circumstances that trigger the actual retirement, and the IRS and the courts give the board considerable discretion in determining when to retire capital credits.

Keyword

reserves *Funds set aside to meet* expected or unexpected future needs, such as plant expansion or storm recovery.

IRS Revenue Ruling 72-36 allows a co-op to establish and maintain "reasonable reserves" for any legitimate business purpose, such as plant expansion, repayment of debt, storm recovery or the purchase of new businesses.[28] The IRS requires all co-ops to keep records of the rights and interests of members in reserve accounts but does not require tax-exempt co-ops to notify members of their interest in reserves. If the reserve is no longer needed, the funds in the account may be reassigned to capital credits.

The ruling prohibits the unreasonable accumulation of capital beyond the reasonable needs of the organization's business, but it says that whether there is an improper accumulation of funds depends on individual circumstances. There has been no test case on this issue, and there is very little legal guidance to define reasonable reserves. Thus, depending on the board's tolerance for risk, some co-ops maintain relatively low reserve levels while others maintain high reserve levels, even when it means that they do not retire capital credits. In practice, a board may be able to delay patronage capital retirements based upon a decision that capital is needed to meet specific business purposes.

The IRS has rarely challenged the business judgment of boards that fail to authorize capital credits retirements. At some point, however, capital accumulation may exceed any legitimate business need. If challenged by the IRS, this has the potential for serious consequences, such as the loss of cooperative status under federal tax law and member relations problems, which could lead to lawsuits to claim member capital or even action by members to sell the system in order to recoup their investments in the cooperative.

Under state law, if an electric cooperative allocates capital credits, then it probably has a legal obligation to retire these capital credits at a later date. The cooperative's board of directors, however, has considerable discretion in deciding when and how to retire capital credits, in accordance with any bylaw, policy or other requirements. If the board retires capital credits in an unreasonable, improper or arbitrary manner or if it fails to retire capital credits without a reasonable, proper and non-arbitrary reason, then the directors may be liable for abuse of discretion. There appears to be little statutory or case law specifying the parameters for abuse of discretion liability regarding capital credits retirements. Existing case law holds that, when addressing rates, capital credits and similar issues, directors of electric cooperatives are protected by the business judgment rule. In addition, courts have been hesitant to interfere with cooperative decisions regarding the retirement of capital credits.[29]

Nevertheless, directors have an obligation to make responsible decisions. It is important that each board member understand the board's retirement policies and decisions, including whether, how much and how to retire capital credits. As the members' representative, each director must be able to explain the issues and decisions to members who have questions.

WHAT AMOUNT OF CAPITAL CREDITS SHOULD THE CO-OP RETIRE?

It is the board's responsibility to determine whether the co-op is in a financial position to retire capital credits and, if so, the dollar amount to retire in a given year. That decision is influenced by a number of factors, including:

- The co-op's financial performance,
- Its equity management plan,
- Rate competitiveness, and
- Regulatory bodies.

Other considerations include lender requirements[30] and the views of the financial markets,[31] both of which influence the cooperative's ability to obtain funds in the future. The board may choose to retire a percentage of the previous year's margins, capital credits allocated for specific years or a specific dollar amount.

[28] The complete text of Revenue Ruling 72-36, 1972-1 C.B. 151 is shown on page 58.
[29] For more information, please see Section B-4, Obligation to Retire in *Legal Issues Associated with Capital Credits*, available online at Cooperative.com.
[30] See page 61.
[31] See page 62 and *Comments of Fitch Ratings*, available online at Cooperative.com.

Financial Performance

The board should consider the impact of any proposed capital credits retirement on the cooperative's liquidity, equity level and rates along with its ability to comply with loan agreements and mortgage covenants. A sound equity management plan can help the board evaluate this issue.

Equity Management Plan

It is good business practice to generate adequate capital to fund operating costs, reserves and some pre-determined portion of plant growth and renewal, but a cooperative should not retain capital above a level that is reasonable and justifiable. A sound equity management plan can help a co-op meet this test by balancing the need to maintain adequate levels of equity, obtain debt at a reasonable cost and retire capital credits in a timely manner. The plan should reflect individual factors affecting financial requirements, including:

- The cost and availability of capital,
- Loan and mortgage requirements of lenders,
- Capital requirements for utility plant, and
- The co-op's competitive position.

The equity management plan should take into account the need to ensure fairness across the generations of members served by the co-op.

An equity management plan helps a co-op manage debt, equity, rates and capital credits, given the system's rate of growth, and existing and proposed capital structure. The plan should not be a static document. Good business planning requires that the plan be reviewed and updated annually to reflect changing circumstances, such as fluctuations in the cost of debt and equity capital, changes in the rate of growth, competition and other variables.

The first step in developing the plan should be to determine the cost of capital. The cost of debt depends on a number of factors, including the capital markets, the cooperative's own financial strength and changes in government lending programs. The cost of debt is generally less than the cost of equity. Since a cooperative is not allowed to pay a return on equity contributed by its members, some people say that the cost of equity to a cooperative is zero, but that is incorrect. The Goodwin formula[12] offers a more realistic view. It calculates the rate of return on equity a co-op must earn to maintain equity at a given level while meeting growth needs and retiring capital credits. It shows that there is a cost to equity even for a co-op experiencing very low growth.

Recommendation
Management Equity Plan

Every electric cooperative should develop and implement an equity management plan that supports its capital credits policy based on the co-op's equity and debt requirements, financial performance and competitive situation. The equity management plan should include rates that will generate adequate cash to provide capital credits retirements.

Keyword

equity management The phrase the cooperative network has historically used to refer to capital structure planning and decision making.

[12] Additional information about the Goodwin formula can be found in Appendix 6.

Survey Result

Sixty percent of respondents to the task force survey say their capital credits retirement program is based on a formal equity management or financial plan.

Source: *Survey Report*, Capital Credits Task Force, March 9, 2004

It is also important to consider the viewpoint of the member, who loses the opportunity to use the funds retained by the cooperative for other purposes, such as investments or retiring personal debt. While each member is different, the cost of its equity investment in the co-op is probably at least as high as the return the member could expect to earn on a similar investment, such as a 10-year Treasury bond, and may be as high as a credit card rate.[43]

In considering the cost to members, it is important to consider the cost of equity in reserves as well as the cost of equity allocated as capital credits. Like margins, money to fund reserve accounts comes from contributions from members, which carry a cost to the member.

Some cooperatives have reached the conclusion that it is in the members' best interest to finance the co-op entirely through equity, while others would use 100 percent debt financing if possible. The best approach avoids either extreme. Higher equity provides flexibility and a cushion against hard times, such as a natural or financial disaster, but may make a takeover more attractive to members. If a co-op maintains a very high level of equity and fails to return capital credits, it may also raise a question as to whether the co-op is operating on a cooperative basis. Lower equity raises concerns for lenders and may affect the co-op's ability to obtain new debt capital, a particularly important concern for co-ops experiencing faster rates of growth. Higher equity may result in a lower interest cost on debt, although this is less of an issue with program lenders. The cost of debt is still likely to be less than the opportunity cost for the member's equity, so lower equity is likely to result in a lower overall cost to the member.

A carefully considered equity management plan can help a system balance these competing interests to determine its optimum equity level. Maintaining equity in the optimum range provides the lowest cost of capital, ensures that the co-op has access to adequate capital and allows for return of capital credits on a reasonable basis. The Boatman Theorem, developed by Jim Boatman, who served as an area representative and director of Planning and Program Analysis for CFC, offers one method for determining the amount of equity that should be retired as capital credits each year. It says that the percentage amount of equity that should be returned each year is equal to the difference between the co-op's rate of return on equity (which can be determined from the Goodwin model) and the co-op's growth in capital.[44]

Rate Competitiveness

Rate considerations are an important part of a co-op's equity management plan. Most co-ops do not have to choose between having competitive rates and retiring capital credits. Developing an equity management plan that includes rates sufficient to provide for capital credits retirements is an essential part of the planning process.

[43] See page 49.
[44] Additional information about the Goodwin formula can be found in Appendix 6.

The cash members receive from capital credits retirements may effectively offset part of costs paid through rates. Depending on the retirement method adopted, this can have an immediate impact.

Regulatory Requirements

Cooperatives that are subject to state regulation of rates or other activities must comply with any regulatory rulings affecting capital credits retirements.[15]

HOW DO CO-OPS FUND CAPITAL CREDITS RETIREMENTS?

Even co-ops that are strongly committed to retiring capital credits sometimes express concern about having adequate cash to fund capital credits retirements and meet other needs. While margins and depreciation on plant investment are sources of funds for patronage capital retirements, there are competing uses for the cash, such as plant additions and principal payments on existing debt.

Some cooperatives have expressed a concern that they may have to adopt higher rates or borrow funds to repay capital credits. As a practical matter, planning for availability and use of cash involves a process that considers funding capital additions, amortization of existing debt, capital credits retirements, rates and rate parity, and equity levels. Cooperatives should develop equity management plans that take into consideration the many uses of funds and the need to build and/or maintain financial strength for future ratepayers. Cooperatives pay for capital additions with general funds, and often requisition debt after construction is completed. Good cash management demands that funds be borrowed only when they can be put to use, as the co-op is unlikely to be able to earn a return on invested funds that is higher than the cost of borrowing. It is an acceptable practice to borrow, if necessary, in order to have the actual cash to retire patronage capital. If the cooperative is following its equity management plan, it should be indifferent to the actual source of cash at the time of retirement. Ultimately, all costs to the cooperative are funded out of rates, either directly or through payments of principal and interest.

Recommendation

Adequate Equity Level

Each electric cooperative should seek to maintain an equity level adequate to retire capital credits on an annual basis and meet the goals and requirements of its equity management plan. The task force suggests that a reasonable equity level for most distribution systems is in the range of 30 to 50 percent, depending on the cooperative's financial and competitive situation.

[15] See page 61

Learn from Experience
Butler REC Strikes a Healthy Balance

At Butler Rural Electric Cooperative in Oxford, Ohio, capital credits are an integral part of the strategic planning process and play a significant role in ensuring that its members are protected as much as possible from volatile rates.

"Like other co-ops, we believe our more than 10,000 members are our highest priority," General Manager Michael Sims said. Butler continually strives to be responsive to its local communities and to improve the lives of its members. "For many years, our board has viewed our capital credits policy as not only a way to show our members how we are different from other utilities but also as a tool for enabling us to offer them competitive and stable rates."

Butler uses a percentage/FIFO hybrid for returning capital credits. "We return 100 percent of capital credits accrued 15 years prior and a percentage of the previous year's patronage," Sims said. "Last year we had an exceptional year. A very cold winter and a very warm summer caused our kwh sales and margins to soar. While we normally might return about 15 percent of current-year margins, last year our board decided to return 35 percent. Our members appreciate that we keep rates stable but that they also see a special reward through capital credits when we have an exceptional year."

Communication becomes very important for Butler so members understand the role of capital credits. Using its 10-year financial forecast, which is an important part of its equity management plan, Butler plans for the long-term with an emphasis on minimizing rate fluctuations. "Balance is very important. Our capital credits approach is designed to provide a cushion of rate protection for our members. When things are good, they benefit. Other years, the payout is more modest," Sims said. "For three years now, we have done an annual customer attitude survey. Our survey tells us that our members seem to recognize and understand the value of this approach." Butler strives to keep communications with its members very straightforward and not technical. In addition to its member newsletter and bill statements and stuffers, Butler boasts a dynamic Web site, including an informative, easy-to-read FAQ section on capital credits.

"When we're able to explain why we're different, members embrace our cooperative roots," Sims said. Predictable rates, reliable electric service, and strong ties with community do tell the cooperative story, and will keep the story alive and well far into the future.

WHAT METHOD OF RETIRING CAPITAL CREDITS BEST MEETS THE CO-OP'S STRATEGIC GOALS?

In addition to determining what level of capital credits to retire, the board must also determine how to retire capital credits.

Lenders earn a return on their investments in loans through interest payments. Investors in stock companies earn a return on their investments through dividends and capital appreciation. Members do not earn a return on their investment (through margins) in a cooperative. Instead they receive the benefits of electric service provided at a cost that does not include profits, and their investment, or margins paid, is ultimately returned through capital credits retirements.

Unless the bylaws or other authority specify retirement procedures, it is up to the board to decide how capital credits are returned. In determining a method, the board should consider factors such as:

- **Cooperative philosophy** Who should provide equity to the co-op, current and newer members or longer-term and former members?
- **Membership expectations** Do the members expect to receive a retirement every year?

- **Demographics** Is the membership of the cooperative stable, or is the rate of turnover high?[56]
- **Customer classes** Are sales predominantly to residential consumers, or are there significant sales to commercial customers?
- **Cooperative's accounting procedures** Can the cooperative's accounting system and data service provider easily implement the method chosen?
- **Sellout exposure** Could failure to retire capital credits lead to internal or external pressure to sell the cooperative?

The board also must consider the desirability of special retirements, such as those to estates, in addition to general retirements to all members and whether to discount capital credits, either voluntarily or involuntarily, for general and/or special retirements.

Each method for retiring capital credits has advantages and disadvantages, and the one chosen should be the one that best meets the objectives of the individual cooperative. Common retirement methods for general retirements include:

- First-in, first-out (FIFO),
- Percentage of total allocated capital credits,
- Last-in, first-out, (LIFO),
- Percentage/FIFO hybrid, and
- FIFO/LIFO hybrid.

While FIFO continues to be the most commonly used method, the use of hybrid approaches is increasing because they provide benefits to current consumers.

In adopting any new capital credits retirement plan, the board should be sure to consider potential legal and accounting issues, including what is fair to longer-term members. If an electric cooperative's bylaws require it to retire capital credits according to a specific method, then there are unique legal issues to consider if a bylaw amendment is necessary. For example, if an electric cooperative amends its bylaws to revise the method for retiring capital credits, then members not voting for the amendment could argue that their conditional contract right to capital credits retirements under the previous method is sufficiently substantial that they are not bound by the bylaw amendment. If, however, they accept capital credits retirements under the bylaw amendment, then they may be prevented from challenging the amendment. The legal issues involving amending capital credits retirement bylaws are complex and often unclear. For additional information, see "Legal Issues Associated with Capital Credits Retirements," which can be found on Cooperative.com.

Recommendation
Selecting Retirement Method Based on Goals

Each cooperative should choose a retirement method that will help the co-op achieve its goals, recognizing the effect the tenure and age of its members has on the perception of the value of membership in the cooperative. The task force strongly recommends that each cooperative know the percentage of its current membership receiving a capital credits retirement each year and seek to maximize that percentage.

[56] About 14.2 percent of U.S. residents moved in 2005. For more information, see page 65

Survey Results

Eighty-three percent of respondents to the task force survey said that the co-op's bylaws allow the board to select the capital credits retirement method while 17 percent said that the bylaws require a specific method. Respondents reported using the following retirement methods:

Method	Percent Using
FIFO	43%
LIFO/FIFO Hybrid	21%
Percentage/FIFO Hybrid	15%
Other	21%

Source: *Survey Report*, Capital Credits Task Force March 9, 2004

FIFO

The FIFO method retires capital credits in the order in which they were allocated. It is the method most commonly used historically and today, and it is one of the easiest to administer. It can be defended from the standpoint that each generation of members pays its own way. FIFO's goal is to keep every member's money for the same period of time. It is most favorable to long-term members, whether they are still receiving service or not. Those who have provided capital to the cooperative for a longer time without receipt of interest or dividends, obtain a return of that capital before other members who made capital available to the cooperative for a shorter period of time. Systems with low growth and member turnover may continue to benefit from the FIFO retirement method, because most members will receive services and remain active, loyal members for a long time.

However, FIFO may no longer be the best method for other cooperatives. There is a significant delay between the time when the member receives a capital credits allocation and receives the first retirement. It is not favorable to newer members, who may use larger amounts of electricity than members did years ago and therefore contribute more to overall equity.

FIFO does little to build loyalty among newer members or to educate those members about the benefits of cooperative ownership.

Percentage of Total Allocated Capital Credits

The percentage method retires a percentage of each member's total capital credits account, regardless of when the capital credits were allocated. For example, if the co-op decides to retire 5 percent of its capital credits, each member would receive payment for 5 percent of its total capital credits contributions. An advantage of this approach is that both longer-term and newer members share in the distribution of capital, providing an educational and member loyalty opportunity for all members. Another advantage is that it provides the biggest refund to those who have contributed the most capital to the organization (the higher amount in the capital credits account, the greater the dollar amount of the retirement). The percentage method emphasizes a member's total participation in the co-op over time rather than that of a single year.

However, some members may raise the question as to why some recent allocations are retired ahead of older allocations. There also may be additional administrative requirements to maintain records, as it may take longer to completely retire the oldest allocations.

In the case of inactive members, if a percentage of each capital credits account is returned each year, the total amount of the account will get smaller and smaller but will never reach zero. The board should establish a minimum level for former members' accounts at which the entire balance will be refunded.

Learn from Experience
Wood County EC Takes Pride in Giving Back to Community

Situated in beautiful northeast Texas about 90 minutes east of Dallas, Wood County Electric Cooperative takes pride in giving back to its community. Wood County's directors and employees serve on local school and industrial boards, participate in chambers of commerce and show up regularly at 4-H club meetings, livestock shows and other local events. "We're driven by a unique spirit of cooperation and independence," General Manager Debbie Robinson said. "We seek to provide the most reliable, cost-effective electric power possible to our members, and we strive daily to fulfill the dreams of our founders."

But the giving back to community doesn't stop here. Since the mid 1970s, Wood County has been retiring capital credits to its 22,000 members based on the percentage method. "Based historically on an RUS guideline, we generally retire 25 percent of prior year's margins," Chief Financial Officer Trey Teaff said. "However, this is an annual decision, and our board uses our 10-year financial forecast along with our equity management policy as a tool for determining the dollar amount of our retirement. To calculate an individual member's payout, we take the total retirement dollars and divide them by the total allocated balance for all current and former members. This gives us our factor—or percentage. This factor is then multiplied by the capital credits balance in each member's account to determine the check amount."

Using the percentage method, nearly 70 percent of Wood County's current members received a check this year. "It generally only takes a few years for a new member to have a capital credits account balance big enough to pay out," Teaff said. "There is great value to reaching this many members...particularly when it comes in the form of a check just before the holidays. Very few people are excluded, and the longer you've been receiving electric power from us the more you benefit."

While Wood County is a mostly rural system, the co-op experiences steady growth each year. This Texas co-op's capital credits approach reaches out to newer members effectively but it also recognizes, rewards and, in Texas style, "tips its hat" to long-time supporters.

LIFO

The LIFO method retires capital credits in the reverse order in which they were allocated. It provides an efficient way to get money back into the hands of current members almost immediately. It can help a cooperative with a fast-growing or transient membership build loyalty because it demonstrates the benefits of the cooperative business model immediately. It also minimizes the difficulty of locating former members to make retirements.

One drawback, however, is that members who have had capital invested in the cooperative for the longest period of time are the last to be paid back, and some longer-term capital credits investments may never be repaid. This has the potential of creating public relations or other difficulties if the older or former members perceive they are being penalized and challenge the board's action. For these reasons, LIFO is generally not used alone but rather is adopted as part of a hybrid approach.

Hybrid Methods—General

Hybrid methods combining two or more approaches are becoming increasingly popular because they allow the co-op to honor the contribution of longer-term members while also recognizing the contribution of other, newer members.

The greatest benefit of the hybrid approach is that the advantages of one retirement method chosen can partially offset the disadvantages of the other. A hybrid plan, however, may require more staff resources because it may be more difficult to explain to members and to administer.

LIFO/FIFO Hybrid

The LIFO/FIFO hybrid is currently the major alternative to the FIFO technique. It recognizes the contributions of longer-term members while providing retirements to most current members.

It may, however, require more staff resources and may also exclude former members with capital credits that are neither first nor last in but rather between those extremes.

Percentage/FIFO Hybrid

The percentage/FIFO hybrid is the third most commonly used technique. It provides a way to continue to recognize the contribution of longer-term members while providing a refund to most members. It also can be a useful tool for transitioning from FIFO to the percentage approach. This method also emphasizes a member's total participation in the co-op over time rather than that of a single year.

It may, however, require more staff resources, and some members may raise the question as to why some recent allocations are retired ahead of older allocations.

SHOULD THE BOARD AUTHORIZE SPECIAL RETIREMENTS?

The board may decide as part of its policy to authorize special retirements of capital credits to recognize special circumstances. Retiring capital credits to the estates of deceased members is a widespread practice with 73 percent of the co-ops responding to the task force survey reporting estate retirements. In recent years, some co-ops have implemented, or considered implementing, other special retirements, including:

- Members who have attained a certain age,
- Inactive members,
- Overdue accounts, and
- Early general retirements.

Since the 1976 capital credits study, there has been a trend toward discounting early retirements.[17]

The board must decide whether the advantages of a particular special retirement outweigh any possible disadvantages. One question to consider is whether special retirements unlawfully discriminate against some members in favor of others. From a cooperative law standpoint, unless a governing legal authority, such as state law, federal law or the co-op's bylaws, says otherwise, the cooperative can probably make special retirements as long as the retirements are reasonable and fair and as long as all similarly situated members are treated the same. Whether a particular special retirement is determined to be reasonable and fair depends on the specific facts and circumstances of the individual cooperative and retirement. Every cooperative should consult its legal and tax advisers regarding its current and proposed special retirements.[18]

Estates

Although discretionary on the co-op's part, the most common special retirement is to estates. From the members' perspective, estate retirements help the family of the deceased member meet funeral costs and other expenses and allow the estate administrator to achieve a timely settlement of the estate. The major benefit to the co-op is that it closes out the member's records. It can be difficult and sometimes impossible to locate the heirs of an estate 20 years after the death of a member. This can result in unclaimed capital credits being paid to the state under the Uniform Disposition of Unclaimed Property Act or a possible escheat situation. If a co-op retires capital credits to the estates of deceased individual members, there is a legal issue regarding whether it must retire capital credits to dissolving or liquidating corporate members.

[17] See page 47.
[18] For more information, please see Section E, Special Capital Credit Retirements in *Legal Issues Associated with Capital Credits*, available online at **Cooperative.com**.

Learn from Experience
Linn County REC Says It's Not Magic…It's Just Good Business!

While Linn County Rural Electric Cooperative, Marion, Iowa, is quick to say that there's nothing magical about what they're doing with capital credits, this mid-sized cooperative is getting the attention of its growing membership in simple ways through consistency, flexibility and communication.

When asked how long they've been retiring capital credits, Linn County CEO Kim Colberg jokingly responds, "Well…since the beginning of time, of course!" That's a slight exaggeration, but the cooperative has made it a high priority to consistently return capital credits to members since its incorporation, with few exceptions. "Up until the late 1990s we had always used the traditional FIFO method but, as part of our long-term planning process, our board felt we really needed to rethink our approach," Colberg said.

The co-op learned from a study done by its power supplier that a very large percentage of its membership has been on line for less than five years. The traditional capital credits policy was "doing the job," but there was clearly a missed opportunity for enhancing Linn County's relationship with its growing number of newer members. "As you'll hear from other cooperatives, getting the attention of these newer members is never easy," Colberg said. "Our decision to change to a hybrid method—we now return a percentage of our current year's allocation along with earlier allocations—has gotten our members' attention and it has made a difference."

The co-op aggressively communicates the value of capital credits and promotes all of its capital credits activities in its newsletters, on its Web site, and in its bill statements. Linn County's members receive their capital credits in the form of a credit on their bill. "We've saved money with this approach but, more importantly, we've received positive feedback from our members that they prefer the credit. It just becomes very important to show the credit as a separate line item so it doesn't go unnoticed. Additionally, we show the credit in a note box at the top of each bill," Colberg said. "We have also found that many commercial members prefer to see the credit on their bill. Oftentimes, when a check is mailed, it's goes to corporate headquarters and gets lost in the shuffle. From the co-op's perspective, it's nice to showcase the savings in a visible way that is reflected on their bill."

Linn County's situation isn't unique but it does serve as a reminder that as cooperative communities and memberships evolve, so must cooperative policies. "Our board wanted the utmost flexibility to use capital credits as another way of reaching and educating our newer members while still effectively and fairly serving our long-time members," Colberg said. Linn County's policy reflects its desire to balance these needs with the important task of ensuring the co-op's financial health today and far into the future.

Age-related Retirements

Retiring capital credits to members who reach a certain age, 65 for example, benefits the member directly instead of the estate and rewards older members for their loyalty to the cooperative. It may, however, be discriminatory against other members unless a discount is applied, or it may become a financial burden to other members as the membership ages.

If the co-op does not receive federal financial assistance, there does not appear to be a general prohibition against this type of discrimination. However, if the co-op receives federal financial assistance from RUS or otherwise, then age-related special retirements may violate the Age Discrimination Act of 1975 (ADA) as well as RUS and other regulations.[39] In addition, depending on the outcome of current deliberations, SFAS No. 150 may require a cooperative to classify as a liability capital credits that will be retired when a member reaches a specific age.

[39] For more information, please see Section E.3. Age in *Legal Issues Associated with Capital Credits*, available online at Cooperative.com.

Recommendation
Age of Members

Electric cooperatives should not make special capital credits retirements based solely on the age of the member.

Inactive Members

As with retirements to estates, retiring capital credits to inactive members, such as those moving out of the service territory, simplifies record-keeping and eliminates potential escheat situations. A possible problem, however, is that a member could change the name of the service from one member of the household to another in order to get the refund. The board may wish to apply conditions to this type of special retirement, such as a period of time that the account must be inactive. This approach also may improperly discriminate against active members unless an appropriate discount is applied to the refund.

Bad Debts

Under the bylaws of most electric cooperatives, unpaid debts to the cooperative are offset against retired capital credits. Under a policy of general application, some cooperatives use special retirements to reduce bad debts by retiring capital credits and applying the amount to inactive accounts of members who leave the cooperative owing money. Co-ops also can apply a discount to the retirement[40] and impose a processing fee to reflect the actual cost to the co-op and reduce any incentive for current members to withhold bill payments in order to collect capital credits. This type of special retirement should not be used for active accounts.

While this approach does not actually generate additional cash income, it may help the co-op reduce its bad debts and simplify its books. Keep in mind that if the former member is involved in a bankruptcy proceeding or files for bankruptcy within 90 days after the offset, there may be restrictions on the cooperative's ability to do this.[41]

Other Issues

The IRS permits both voluntary and involuntary special retirements. For example, the co-op may give an estate the choice of voluntarily accepting a discounted retirement now or a full value retirement at the scheduled retirement date. The board could decide to make involuntary retirements to overdue accounts or those leaving the system. Some people say that involuntary retirements are contrary to cooperative principles and that the member should always consent to an early retirement. In addition, state law may prohibit or limit involuntary discounting of capital credits.

Questions to answer in considering any special retirement include:

- Is the retirement fair and reasonable to both the members receiving the retirement and to the other members of the cooperative?
- Are all similarly situated members treated the same?
- Will it pose an undue burden on future or current members?

As with other aspects of capital credits retirements, there is not necessarily a right or wrong approach to special retirements. What is important is for the board to understand the consequences of the decision it makes.

[40] See page 47.

[41] For more information, please see Section F, Security Interest in Capital Credits in *Legal Issues Associated with Capital Credits*, available online at Cooperative.com.

Each Capital Credits Retirement Method Offers Advantages and Disadvantages

Method	Percent Using*	Definition	Advantages	Disadvantages
FIFO First-in, First-out	43	Retires in order allocated	Helps each generation pay its own way; Rewards loyalty of long-term members for use of capital without interest or dividends	Creates significant delay between allocation and retirement; Does not reward newer members, who may use more services and contribute more to overall equity
FIFO/ Percentage Hybrid	15	Combines FIFO and Percentage of Total Allocated Capital Credits approaches	Recognizes use of longer-term members' capital while providing retirements to all members	May have additional administrative requirements; May be less favorable to longer-term members
LIFO Last-in, First-out	1	Retires in reverse of order allocated	Demonstrates benefits of co-op membership by rewarding most members immediately; Reduces difficulty of making retirements to former members	May raise question of fairness as more recent allocations retired ahead of older allocations; Older allocations will never be retired
LIFO/FIFO Hybrid	21	Combines FIFO and LIFO approaches	Recognizes contribution of longer-term members while providing retirements to current members	May have additional administrative requirements; May be less favorable to longer-term members and former members with capital credits between extremes
Percentage of Total Allocated Capital Credits	N/A	Retires percentage of each member's capital credits account each year	Lets older and new members share in return of capital; Provides largest refund to those who have contributed most capital	May raise question of fairness; May have additional administrative requirements
Special Retirements	N/A	Recognizes special circumstances through retirements, such as retirements to estates; may be discounted to ensure fairness	Addresses specific needs for each group; May create permanent equity	May treat members differently; May create taxable income

*Source: *Survey Report*, Capital Credits Task Force, March 9, 2004

Recommendation
Discount Special,
Not General, Retirements

If an electric cooperative chooses to make special retirements, such as retirements to estates, the amount of the retirement should be discounted to reflect the time value of money. Cooperatives should not offer discounted general retirements.

SHOULD THE CO-OP APPLY DISCOUNTS TO EARLY CAPITAL CREDITS RETIREMENTS?

Most cooperatives make both special and general capital credits retirements. A special retirement allows the cooperative to make a payment sooner than it otherwise would. There can be good reasons for doing that, especially in the case of accounts that are no longer active due to a death or a member leaving the system. There is, however, a real cost to the other members of the cooperative to retire capital credits out of sequence, and there is a benefit to the member to receive money sooner than the member would otherwise. Some cooperatives discount, or reduce the amount of, special retirements to reflect the time value of money. Discounting provides a fair way to recognize special circumstances while continuing to treat members equally.

A few cooperatives also offer early general retirements at a discount. The primary reason cited for this is a desire to create permanent equity.[42] The decision to make general retirements out of cycle is, however, different from the decision to offer special retirements. A discounted special retirement offers a fair way to treat atypical circumstances. Discounting general retirements does not have the same leveling effect among the membership because in a general retirement, all members receive the same nominal dollars. It is difficult to administer such a practice fairly while maintaining a strong financial performance, and it may put the cooperative at risk for failing the 85-percent test.

The IRS has issued a number of private-letter rulings concerning discounting capital credits refunds, but the treatment of discounts is an issue that is still evolving. Any discount plan should take into consideration the potential to create non-member income affecting the co-op's tax status under the 85-percent member income test in IRC Section 501(c)(12).

In order to preserve its position in potential litigation with respect to Subchapter T cooperatives, the IRS has taken the conservative position that any amount retained by a Section 501(c)(12) cooperative after a discounted capital credits retirement is non-member income.[43]

Three private-letter rulings in 2003 found that a discounting plan does not adversely affect cooperative status nor does it jeopardize the ability to exclude allocated capital credits from income. These rulings also found that a discounting plan creates non-member taxable income under the 85-percent test since the amount is not maintained in the name of the member. Other IRS rulings issued in 2003 to exempt electric co-ops, however, held that no income would be recognized if the amount of the capital credits retained by the cooperative as part of the discounting process was held in the participant's name and redeemable only upon liquidation.

Keyword

discount To calculate the present value of an amount that would otherwise be received in the future to reflect the time value of money.

[42] See page 19.
[43] The IRS took the position in a case involving Gold Kist, Inc., a Subchapter T cooperative, that the amount remaining after a discounted capital credits refund resulted in non-patronage income because the co-op had received a tax benefit in the form of a deduction of the entire amount. The 11th Circuit Court of appeals in Atlanta ultimately ruled that no income resulted from the discounting. This ruling only applies to Sub T cooperatives in states under the jurisdiction of the 11th Circuit and does not apply to exempt or nonexempt rural electric cooperatives. The IRS is expected to litigate this issue in another jurisdiction.

Other discounting issues that have not been resolved by the IRS include:

- The level of board discretion,
- Whether discounting requires member consent, and
- Whether discounting can be applied to a limited group of members.

The impact of state laws on discounts also is uncertain. Historically, cooperatives have looked primarily to federal tax rules and regulations for guidance on capital credits; however, courts, electric cooperative members and others are increasingly examining the impact of state electric cooperative statutes on capital credits issues.

The Discount Rate

If a cooperative elects to discount some capital credits retirements, the board must then choose the appropriate discount rate. It is important that the board consider this issue carefully, because the discount rate is the key to making discounted retirements fair and equitable. Too high a rate penalizes the member. Too low a rate penalizes the cooperative and its remaining members. The board should be able to justify and verify the rate chosen.

There are various options for the discount rate. Some people argue that equity is free; thus, the discount rate should be zero. Other people argue that the discount rate should be equal to the co-op's cost of equity, because the co-op is giving up equity. There is a cost associated with capital credits returned to members, because it must be replaced, either with debt or more equity.

There is no one standard that is appropriate for every cooperative in every situation. The co-op can evaluate the cost from the perspective of the cooperative, the member or an outside benchmark. The measure chosen should be easy to calculate, easy to explain and defensible. It should be fair to members both individually and collectively. The co-op's weighted cost of capital, which reflects the cost of both debt and equity, meets these criteria.

Since rates change often, the rate chosen should be reviewed and adjusted periodically to ensure that it continues to be fair.

Recommendation

Recommended Discount Rate

If a cooperative makes discounted capital credits retirements, the task force suggests that the discount rate should be based on the cooperative's weighted cost of capital, which includes the cost of equity and the cost of debt.

Survey Results

Seventeen percent of respondents to the task force survey said they discounted general capital credits retirements. Sixty-four percent of survey respondents discount capital credits retirements to estates.

Source: *Survey Report*, Capital Credits Task Force, March 9, 2004

A Co-op's Weighted Cost of Capital Is an Appropriate Benchmark for Discount Rate

The co-op's weighted cost of capital reflects the cost of both debt and equity. It provides a reasonable standard for the discount rate for discounting capital credits retirements. This example assumes a co-op has:

- 40 percent equity,
- 60 percent debt and
- A cost of capital equal to the median for distribution co-ops in 2003, including an average weighted cost of debt of 5.0 percent and an average cost of equity of 9 percent.

Co-op's Weighted Cost of Capital =
[Average Weighted Cost of Debt X Percent Debt] + [Cost of Equity X Percent Equity]

Element of Capital		Co-op's Cost		Percent of Capitalization		Contribution to Cost of Capital
Debt		5.0 %	X	60	=	3.0%
Equity	+	9.0 %	X	40	=	3.6%
Weighted Cost of Capital/Suggested Discount Rate						6.6%

A Capital Credits Discount Rate Should Be Justifiable and Verifiable

Rate	Amount (percent)*
Co-op's average cost of debt	5.0
Co-op's average cost of equity	9.0
Co-op's weighted cost of capital	6.6

Other Benchmarks	Source	Amount (percent)*
Member's long-term mortgage rate	Federal Housing Finance Board	5.96
20-year bond, A-rated utility	Bankrate.com	6.0
Co-op's theoretical cost of equity	Goodwin formula (3 percent growth rate)	6.72–11.71
Investor-owned utility benchmark	Return on equity (after tax)	10–11
Member's alternative investment option	10-year Treasuries	4.2
Member's credit card rate	Bankrate.com	12.7 (fixed) 13.8 (short-term variable)

*As of September 2004

The Discount Rate Should Be Fair to Both Co-op and Member

The following example shows the capital credits retirement due a member that has been allocated $50 each year for 20 years for a total of $1,000 after the retirement has been discounted at various rates.

Discount Rate (Percent)	Discounted Capital Credits Refund to Member	Amount Retained by Cooperative
4	$680	$320
6	$574	$426
8	$490	$509
10	$426	$574
12	$373	$627

Member Consent

If a cooperative may legally discount capital credits retirements without member consent, then a board should still consider making discounted retirements subject to member agreement. For example, a member leaving the service territory would have the option of accepting a capital credits retirement at a discount or leaving the investment with the cooperative until the normally occurring retirement date. If the policy is structured correctly, both the member and the co-op should be indifferent financially to the decision, although some members may have a preference for receiving the retirement sooner rather than later.

HOW MIGHT A SECURITY INTEREST IN CAPITAL CREDITS AFFECT THE CO-OP?

To secure a member's obligation to pay an electric cooperative, the co-op may desire to create and perfect a security interest in the member's capital credits. This security interest may protect the co-op against other creditors of the member, like banks, who knowingly or unknowingly have a security interest in the member's capital credits. It also may provide certain preferences and priorities if the member files for bankruptcy, and it may allow the cooperative to offset discharged debts against the member's retired capital credits. Creating and perfecting a security interest in capital credits has practical and legal advantages and disadvantages. When addressing security interest issues, a co-op should consult its attorney.[44]

HOW MIGHT THE BANKRUPTCY OF A MEMBER AFFECT THE CO-OP?

When a member of an electric cooperative files for bankruptcy, it raises important issues regarding the member's capital credits. First of all, the co-op cannot discontinue service to a member because of the bankruptcy filing or because of debts owed to the cooperative at the time of the bankruptcy filing. The co-op can, however, require the member to provide adequate assurance that the member will pay for future electric service. A co-op could seek to use the member's capital credits as part of this assurance.

Second, the bankruptcy court or trustee may seek to force the cooperative to immediately retire and pay the member's capital credits into the bankruptcy estate. Existing case law, however, indicates that the court or trustee does not have this right. Third, the bankruptcy filing may affect the cooperative's ability to set off or recoup the member's debt to the cooperative (even when the debt is discharged) against the member's capital credits, whether retired now or in the future. Fourth, having a security interest in the member's capital credits may be an advantage, or a disadvantage. Fifth, the bankruptcy filing may impose a duty upon the cooperative to report the member's capital credits to the trustee or court. These issues are complex and confusing and an electric cooperative should consult its attorney.[45]

[44] For additional information, please see Section F. Security Interest in Capital Credits in *Legal Issues Associated with Capital Credits*, available online at Cooperative.com.
[45] For additional information, please see Section G. Capital Credits in Bankruptcy in *Legal Issues Associated with Capital Credits*, available online at Cooperative.com.

Learn from Experience
Farmers EC Gives Members a Fair and Reasonable Choice

When it comes to dealing with the capital credits account of a deceased member, Farmers Electric Cooperative in Clovis, New Mexico, wants to be sensitive to a member's family as well as a prudent steward of all its members' investments. As many cooperatives have experienced, finding this balance is never easy.

"Our board and staff have always pursued an aggressive capital credits policy, which includes a discount policy," Farmers EC General Manager Lance Adkins said. Farmers uses a formula developed by its accounting firm to calculate the percentage of capital credits it will return each year. The co-op generally retires a percentage of its capital credits from every year, ranging from 100 percent of its oldest year's margins to a fairly high percent of its current-year margins. In fact, for the last several years, Farmers has retired from 40 to 50 percent of its current-year margins.

"This policy has worked well for our co-op. We believe that it's important, especially for our newer members, to see that capital credits check each year. We can talk and write about member ownership all we want, but a check makes it real to them," Adkins said. The co-op also offers special capital credits retirements to estates at a discount. "The portion of our policy that allows for discounting is not our most popular program, but we feel strongly that it is reasonable, fair to members, and financially prudent for our co-op."

The kwh sales to Farmers' membership is divided fairly equally between residential, small and large commercial, and irrigators. "It wouldn't have much financial impact to retire capital credits early at 100 percent of their value to residential customers, but this wouldn't be the case with our other member classes," Adkins said. "An early retirement for these members could have a significant financial impact on our co-op. The goal of our policy is treat all our members equally and fairly."

Farmers offers the member's estate representative a choice between receiving the retirement on the normal schedule or receiving a payout of all capital credits at a discounted rate. The discount rate is calculated on sliding scale based on the year of the allocation. Finally, Farmers also offers these members the option to donate their capital credits—at 100 percent on their normal cycle—to an education foundation that funds scholarships for Farmers' members and, sometimes, their direct dependents.

"There's certainly not one answer for this issue. We strive to be fair and to minimize the financial exposure to our co-op long-term," Adkins said. Many co-ops will continue to wrestle with this issue and will need to stay abreast of both tax and legal issues to protect the co-op and its members' investments.

WHAT OTHER RETIREMENT ISSUES SHOULD THE BOARD ADDRESS?

Minimum Amount for Capital Credits Checks

Some cooperatives set a minimum retirement amount for capital credits checks, such as $5 to $10. If the capital credits payment due to an active member is less than the minimum, the retired amount is held until it can be combined with future capital credits retirements to reach the minimum check level. In the case of inactive accounts where there is no expectation of additional future capital credits allocations, the co-op may choose to retire the full amount, possibly at a discount, and clear the capital credits account. Some co-ops apply a reasonable service charge for maintaining records on inactive accounts that do not meet the minimum check amount.

Multiple Accounts

Some consumers have multiple billing accounts, such as an account for a residence and a business. These may be accumulated into one capital credits account. There may, however, be problems if some of the accounts fall into different classes of service covered by different capital credits policies. A co-op can avoid this issue by establishing a different capital credits account for each billing account.

SFAS 150

The current generally accepted accounting procedures for capital credits[illegible] require assigned capital credits with no fixed maturity date to be reported as equity.

In May 2003, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards #150 (SFAS 150) to address issues regarding classification of equity and liabilities. The reason for the proposed standard is to improve the transparency of financial instruments that have both equity and liability characteristics and to conform U.S. accounting procedures to international practice.

As originally proposed, SFAS 150 said that mandatorily redeemable financial instruments, including capital credits, payable at a date certain or when an event certain to occur does occur, should be considered a liability, not equity. In other words, if a co-op member could demand payment based on an event certain to happen, the member's capital credits account would be considered a *mandatorily* redeemable liability. Depending on the ultimate definition of a *mandatorily* redeemable obligation, the proposed standard had the potential to substantially reduce a cooperative's level of equity. The cooperative network was able to gain an indefinite delay in the implementation of this standard while the matter was under consideration.

NRECA, CFC and RUS filed joint comments with the FASB in October 2003, arguing that the Board discretion exercised in the redemption of capital credits upon the death of its members or under other circumstance is little different from the discretion that boards of for-profit companies exercise in distributing dividends to shareholders. If future dividend payments are not to be considered a liability under SFAS 150, then capital credits should not be considered a liability.

In October 2004, the FASB tentatively adopted a new-equity liability classification plan that would base the equity or liability classification of financial instruments issued by a business enterprise, including stock, capital credits and other items, on the degree to which the financial instrument reflects an "ownership relationship" in the business. Financial instruments that establish a "direct ownership relationship"—interests that are the most subordinated and that share in the business's risks and rewards, including capital credits—would always be considered equity. Financial instruments with an "indirect ownership relationship—interests indexed to and in the same direction as the most subordinated interest—would be considered equity only if their ultimate settlements, if any, would establish a direct ownership relationship. Otherwise, they would be considered liabilities. Financial instruments that establish neither a direct nor indirect ownership relationship will be considered liabilities if they require or may require settlement.

Under this plan, cooperatives would continue to report their allocated capital credits on the balance sheet as equity without regard to any obligation to retire the capital credits. The proposed reporting approach, if finalized, would essentially reverse prior FASB interpretations of SFAS 150 that co-op capital credits with a legal or constructive obligation to retire should be reported on the co-op balance sheet as a liability.

The FASB is now considering a requirement to report financial instruments with a direct ownership relationship, such as capital credits, that carry a settlement obligation as a separate line item of equity identifying the obligation to retire. If this proposal is ultimately adopted, however, unlike the earlier SFAS 150 liability treatment of capital credits, it should not impact the results of a co-op's financial ratios and tests.

[illegible] AICPA Audit and Accounting Guide *Audits of Agricultural Producers and Agricultural Cooperatives*.

At this writing, issues surrounding SFAS 150 continue to evolve. NRECA, CFC and RUS will continue to monitor and respond to the FASB's actions, and NRECA is participating in the FASB's Liabilities and Equity Resource Group to advise the FASB staff. (Current information on the status of SFAS 150 is available on Cooperative.com.)

CAN THE CO-OP USE UNCLAIMED CAPITAL CREDITS TO ADD VALUE FOR MEMBERS?

Former cooperative members should inform the co-op of any changes in address so that the co-op can locate them for future capital credits retirements. As a practical matter, many do not. If the co-op wishes to locate the member, Internet searches, national telephone directories and U.S. Postal Service records can help track them down.

If a former member does not claim retired capital credits, then state law governs the right to these unclaimed capital credits. Forty-four states have adopted an unclaimed property act. These acts provide for the state to take custody of (but not title to) property that is not claimed for a specified period of time. Escheat acts allow the state to take ownership of property that is abandoned or unclaimed for a specified period of time. In general, unclaimed capital credits are governed by an unclaimed property act, instead of an escheat act.

With regard to unclaimed capital credits, 27 states provide that unclaimed capital credits may remain with the cooperative; however, 10 of these states require that the funds be used for specific purposes, such as education, charity or economic development.

In the remaining states, there is apparently no specific statute addressing the co-op's ability to retain capital credits.

Cooperatives without authority to retain unclaimed capital credits have considered several approaches to reducing or eliminating unclaimed capital credits, such as applying a service charge, providing for voluntary or involuntary assignment or transfer of unclaimed capital credits to the cooperative if the member cannot be located in a specified period of time and requiring members to request capital credits retirements. Each of these approaches has unique legal considerations in determining its enforceability. If a co-op adopts such an approach and a court invalidates the action, the co-op may have to pay interest and penalties to the state as well as the full amount of the unclaimed capital credits.

Each cooperative should review its practices to be sure they are in compliance with appropriate law. Cooperatives that must render unclaimed capital credits to the state may want to consider requesting statutory relief.[47]

Some States Allow Cooperatives to Retain Unclaimed Capital Credits

State Law Provisions	States
Co-ops retain with no conditions	Alabama, Alaska, Arkansas, Florida, Idaho, Illinois, Indiana, Kansas, Michigan, Mississippi, North Dakota, Oklahoma, Oregon, South Dakota, Virginia, Washington, Wyoming
Co-ops retain with conditions	Colorado, Delaware, Iowa, Louisiana, Minnesota, Montana, New Mexico, Texas, Utah, Wisconsin
No express statute	Arizona, California, Georgia, Hawaii, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Vermont, Virginia

[47] For more information, see Section II, Unclaimed Capital Credits in *Legal Issues Associated with Capital Credits*, available online at Cooperative.com.

Chapter 4: Compliance Issues

Questions for the Board's Consideration

- Is the co-op in compliance with federal laws and regulations affecting capital credits allocations and retirements?
- Is the co-op in compliance with state laws and regulations affecting capital credits retirements?
- Are the co-op's capital credits policies in compliance with the requirements of lenders?
- Are the co-op's capital credits policies compatible with the requirements of the financial markets?

A cooperative's policies for allocating and retiring capital credits should be in compliance with applicable state and federal laws as well as the co-op's articles of incorporation and bylaws. The policies should take into consideration the requirements of lenders and the financial markets. Directors should understand the legal and financial consequences of decisions they make about capital credits.

Recommendation:
Flexibility and Discretion

Every electric cooperative should review its bylaws, state laws and other applicable governing factors in terms of the impact on capital credits policies. If a cooperative's bylaws do not permit the board to exercise sufficient discretion regarding the method for allocating or retiring capital credits, the cooperative should consider seeking changes to give directors such flexibility in determining capital credits policies.

IS THE CO-OP IN COMPLIANCE WITH FEDERAL LAWS AND REGULATIONS AFFECTING CAPITAL CREDITS ALLOCATIONS AND RETIREMENTS?

Federal laws provide special tax rules to recognize the value of cooperative businesses. IRC Section 501(c)(12) grants tax-exempt status to electric and telephone cooperatives, among others, if certain conditions are met. IRC Section 1381-1388 (Subchapter T) applies to most other cooperatives. While these cooperatives are taxable, Subchapter T allows them a tax deduction for patronage-sourced income allocated to their patrons if the requirements regarding allocations of patronage capital and other conditions are satisfied. Electric and telephone cooperatives that do not qualify for tax exemption under Section 501(c)(12) are not subject to Subchapter T and are governed by co-op case law established before Subchapter T was enacted in 1962.

Mutual Company or Cooperative?

IRC 501(c)(12) provides a federal income tax exemption to certain mutual companies and cooperatives that meet other requirements. What's the difference? Both are organized to provide services—often those that would not otherwise be available—to member-owners essentially at cost. The key difference is how they treat any margins collected.

A **mutual company** uses any margins above the cost of providing services to reduce costs in future years. Examples of mutual companies include mutual insurance associations, such as State Farm Insurance, and credit unions, such as the Agriculture Federal Credit Union. There are also a number of mutual electric associations.

A **cooperative** returns its margins to the members through capital credits allocations and retirements.

Income Tax Consequences of Various Forms of Organization

Governing Authority	**Exempt Electric Co-op** IRC Sec. 501(c)(12)	**Taxable Electric Co-op** Pre-'62 Co-op Case Law	**Taxable General Co-op** IRC Sec. 1381 (Sub T)
Requirements to Qualify	Engage primarily in "like organization" activities (utility and ancillary services). Non-like income is non-member income; Operate as a cooperative. Meet the 85-percent member income test.	Operate on a cooperative basis; Receive more than 15 percent non-member income (or have exempt status revoked); Serve in "rural areas" as defined in Sec 5 of the RE Act.	1. Operate on a cooperative basis. 2. Not primarily engaged in providing electric and telephone service to "rural areas."
Determination of Co-op Taxable Income	Exempt for income tax on activities "substantially related" to tax-exempt purpose. Taxable on unrelated business income (UBI).	Segregate income and deductions between patronage and non-patronage-sourced activities. Exclude from income any assigned capital credits with respect to patronage-sourced activities.	1. Segregate income and deductions between patronage and non-patronage activities. 2. Deduct capital credits on patronage income (paid minimum of 20 percent cash with remainder written assignment—qualified). 3. Deduct non-qualified written allocations of capital credits on patronage income when paid in cash.
Tax Effect of Capital Credits on Member	1. Co-op is not required to issue Form 1099. 2. If a business, capital credits refund is includable in taxable income at redemption, not allocation.	Co-op is required to issue Form 1099-MISC at redemption over $600. If a business, capital credits refund is includable in taxable income at redemption, not allocation.	Co-op is required to issue Form 1099-PATR over $10 for qualified notices made and non-qualified notices paid. Patron includes in income at assignment, or allocation, for qualified capital credits and at redemption for non-qualified.
Ability to Establish Diversified Activities within Co-op	1. Very limited. Ancillary activities are [a] insubstantial or [b] incident to and in furtherance of utility service. 2. Subject to UBI Tax, if not "substantially related" to tax-exempt purpose.	May engage in diversified activities so long as primary activity is still providing electric/telephone service to "rural areas."	May engage in diversified activities so long as majority of business is still with members (i.e., business is still a co-op).
Ability to Establish Subsidiary for Diversified Activities	According to Rev Rule 2002-55, a tax-exempt electric co-op may establish a for-profit subsidiary for valid business reasons without jeopardizing the parent's tax-exempt status; According to IRC 337(d) liquidation of for-profit subsidiary into tax-exempt parent results in taxable gain on assets appreciation.	No tax restrictions on formation of subsidiary; For-profit subsidiary income is non-patronage sourced, and hence, taxable. Tax-free liquidation of for-profit subsidiary into taxable parent.	No tax restrictions on formation of subsidiary. For-profit subsidiary income is non-patronage sourced, and hence, taxable. Tax-free liquidation of for-profit subsidiary into taxable parent.
Ability to File a Consolidated Tax Return (offsetting losses of subsidiary against taxable income of parent)	Consolidated return cannot be filed for tax-exempt organization.	Consolidated return is permissible.	Consolidated return is permissible.

*Source: IRS Regulations, Section 1.61 5

IRC Section 501(c)(12)

IRC Section 501(c)(12) exempts certain cooperatives, including electric and telephone cooperatives, and mutual companies from federal income taxation if they provide utility and related services to members, and if they pass the 85-percent test. While some Section 501(c)(12) utilities may choose to operate as mutual companies, the tax issues associated with mutual companies are beyond the scope of this report.

In order to qualify for the federal tax exemption under Section 501(c)(12), a cooperative must:

- Engage in specified activities,
- Operate under cooperative principles, and
- Derive 85 percent or more of their income from members annually.

Cooperative principles IRC Section 501(c)(12) does not define what it means to operate as a cooperative. The IRS has, however, adopted key principles[48] based on case law and experience, including:

- *Subordination of capital.* The members of the cooperative (unlike shareholders in an investor-owned firm) control the cooperative and share in any savings or financial benefits. Voting rights are based on membership—one member, one vote—rather than financial investment in the organization or use of services. Interest or dividends are not paid on members' equity investments.
- *Democratic control by members of the cooperative.* Members participate in policy- and decision-making for the organization. A co-op holds annual meetings for members to elect board members to operate the co-op, to approve certain matters affecting the governance of the cooperative and to otherwise participate in guiding the organization.
- *Vesting in and allocation of capital credits among the members.* The excess of a cooperative's operating revenues over its operating expenses belong to its members. The organization must allocate any operating margins to members in proportion to the amount of business done with the cooperative.
- *Operation at cost.* A cooperative must not operate for profit and should strive to avoid losses.

The 85-percent test Once the IRS issues a determination letter granting tax-exempt status, a co-op is exempt from federal income tax in any year in which it receives 85 percent or more of income from members for the sole purpose of meeting losses and expenses. There are two requirements for member income: it must be collected from members on a cooperative basis, and it must be derived from services specified in Section 501(c)(12).

If the co-op fails the test in a given year, it is subject to federal income tax for that year. However, it does not have to re-apply for exempt status if it continues to meet the other Section 501(c)(12) requirements. Thus a co-op could pass the test in Year 1, fail (and pay income taxes) in Year 2 and pass again in Year 3 without changing its status with the IRS.

It is possible—and it has happened with a few G&Ts—for the IRS to revoke tax-exempt status if an agent auditing the cooperative sees evidence that the co-op is unlikely to pass the 85 percent test in the foreseeable future.

Other issues Exempt electric cooperatives are required to pay federal taxes on any unrelated business income. For example, sales and service of appliances to customers who do not purchase electricity from the cooperative generate unrelated income, which is subject to taxation.[49]

Exempt cooperatives are also subject to restrictions on diversified activities. Generally, any income from activities that do not qualify for exemption must be treated as non-member income for purposes of the 85-percent member income test, even if the customer is a member of the cooperative.

[48] Exempt Organizations; Proposed Examination *Guidelines Regarding* Rural Electric Cooperatives. Announcement 96-24, 1996

[49] Exempt Organizations; Proposed Examination Guidelines Regarding Rural Electric Cooperatives. Announcement 96-24, 1996.

Many cooperatives are concerned about the consequences of failing the 85-percent test. While the co-op would have to pay income taxes on non-patronage-sourced income (approximately equivalent to non-member income), patronage-sourced income is eligible for exclusion from federal gross income and may, therefore, be nontaxable, provided the cooperative properly notified members of the dollar amount of annual capital credits allocations. For most cooperatives, the remaining taxable income is likely to be relatively small, and the financial impact of losing tax-exempt status maybe minimal under today's circumstances.

Of greater concern is the possibility of a cooperative losing its status as a "cooperative" under federal tax law. In that case, member and nonmember income would be taxed separately under the provisions of IRC 277, the statutory provision that applies to membership organizations that are not tax-exempt under other sections of the tax code. The financial impact of that occurrence could be substantial. It is, therefore, important for the cooperative to protect its status as a cooperative by meeting the IRS requirements for operating as a cooperative.

As the competitive structure of the electric utility industry continues to evolve, some cooperatives may find themselves earning non-member revenues from new sources. In assessing the impact of any new development, co-ops must determine whether it affects the 85-percent test.

Subchapter T

Cooperatives organized under IRC Section 1381, Subchapter T generally operate on a taxable basis. Subchapter T cooperatives are primarily engaged in providing services other than electric and telephone service in rural areas. While some electric cooperatives have organized Subchapter T cooperatives to provide non-electric services, discussion of the issues associated with Subchapter T co-ops is beyond the scope of this report.

Pre-1962 Co-op Case Law

An electric cooperative that fails the 85-percent member income test is considered by the IRS to be taxable. Unlike most taxable cooperatives, however, taxable electric cooperatives are generally not subject to the provisions of Subchapter T, *provided* that they serve "persons in rural areas."[50] Instead, the taxable income of such taxable electric cooperatives is determined under administrative and case law in effect prior to the passage of Subchapter T in 1962 (pre-62 co-op case law). Taxable rural electric co-ops are generally allowed to exclude from federal gross income capital credits that have been allocated to patrons from patronage-sourced income, reducing tax liability, provided the cooperative properly notified members of the dollar amount of the capital credits allocations.

Tax regulations provide that the term "rural area" is the same as the term is defined in Section 5 of the Rural Electrification Act of 1936, as amended.[51] These tax regulations do not specify, however, how much of a cooperative's service area or what percentage of the cooperative's patrons must meet this "rural area" test, so the tax treatment of taxable electric cooperatives that serve in both rural and urbanized areas is an undecided issue.

IRC Section 501(c)(12), which contains the provisions required for an electric cooperative to be tax-exempt, includes no "rural area" requirement. Furthermore, neither qualification for tax-exemption under IRC Section 501(c)(12) nor the applicability of Subchapter T is dependent on whether the cooperative is an RUS borrower.

[50] IRC Section 1381(a)(2)(C).
[51] IRC Section 1.1381-1(b)(4)

Revenue Ruling 72-36, 1972-1 CB 151 — IRC Sec. 501

Reference(s): Code Sec. 501 Reg Sec. 1.501(c)(12)-1

Certain requirements that cooperative companies must meet for exemption under section 501(c)(12) of the code are explained.

Full Text The Internal Revenue Service has received inquiries from cooperative companies regarding certain requirements for exemption from federal income tax under section 501(c)(12) of the Internal Revenue Code of 1954.

Section 501(c)(12) of the code provides for exemption from federal income tax of mutual ditch or irrigation companies, mutual or cooperative telephone companies, or like organizations, if 85 percent or more of their income consist of amounts collected from members for the sole purpose of meeting losses and expenses.

Section 1.501(c)(12)-1(a) of the Income Tax Regulations provides that excess funds on hand at the end of the year may be retained to meet future losses and expenses, or returned to members.

The specific questions and their answers are as follows:

Question 1 Should the interests of members in the savings of an organization be determined in proportion to their business with the organization?

Answer Yes. In accordance with fundamental cooperative and mutual principles, the rights and interests of the members in the savings of an organization should be determined in proportion to their business with the organization. The interests of members in the savings of the organization may be determined in proportion to either the value or the quantity of the services purchased from the organization, provided such basis is realistic in terms of actual cost of the services to the organization.

Question 2 Can funds be retained in excess of those needed to meet current losses and expenses for such purposes as retiring indebtedness incurred in acquiring assets, expanding the services of the organization, or maintaining reserves for necessary purposes?

Answer Yes. However, such funds may not be accumulated beyond the reasonable needs of the organization's business. Whether there is an improper accumulation of funds depends upon the particular circumstances of each case.

Question 3 Where an organization retains funds for purposes other than meeting current losses and expenses, must the organization's records show each member's rights and interest in the funds it retains?

Answer Yes. To maintain its mutual or cooperative character an organization must keep such records as are necessary to determine, at any time, each member's rights and interest in the assets of the organization.

Question 4 What is the effect on exemption of a forfeiture of a former member's rights and interest where the bylaws provide for such forfeiture upon withdrawal or termination?

Answer If, under the bylaws, a member's rights and interest have been forfeited, the organization has not operated on a mutual or cooperative basis and is therefore not exempt.

Question 5 Where, upon dissolution, an organization has gains from the sale of an appreciated asset, how should these gains be distributed?

Answer Such gains should be distributed to all persons who were members during the period which the asset was owned by the organization in proportion to the amount of business done by such members during that period, insofar as is practicable.

IS THE CO-OP IN COMPLIANCE WITH STATE LAWS GOVERNING CAPITAL CREDITS?

Enabling Legislation

A cooperative is organized under the laws of the state in which it is incorporated.[52] Traditional electric cooperatives are incorporated and operate in 47 states. The state issues articles of incorporation authorizing the cooperative to be formed and conduct business. Electric cooperatives in approximately 30 states are organized under specific electric cooperative acts. Twenty-eight of these acts address what happens to excess revenues, effectively governing the allocation and retirement of capital credits. Fourteen of these acts contain language similar or identical to the language in Model A; six, Model B; and five, Model C (see below).

Electric cooperatives in 11 states are incorporated under a general cooperative act; in three states, they are incorporated under a nonprofit corporation act; and in three states, under a business corporation act. Most general cooperative acts address excess revenue. Most nonprofit or business corporation acts do not, but they authorize bylaws that may address treatment of excess revenues.

Capital Credits Policies of Electric Cooperatives May Be Governed by State Statutes

The 28 electric cooperative acts that address excess revenues contain language similar or identical to the language adopted in Model A, Model B or Model C.

Model A, 14 States

Alabama, Florida, Kansas, Louisiana, Maine, Maryland, Missouri, Montana, New Mexico, New York, Oklahoma, South Carolina, Tennessee, Vermont

Revenues of a cooperative for any fiscal year in excess of the amount thereof necessary:

1. To defray expenses of the cooperative and of the operation and maintenance of its facilities during such fiscal year;
2. To pay interest and principal obligations of the cooperative coming due in such fiscal year;
3. To finance, or to provide a reserve for the financing of, the construction or acquisition by the cooperative of additional facilities to the extent determined by the board of directors;
4. To provide a reasonable reserve for working capital;
5. To provide a reserve for the payment of indebtedness of the cooperative maturing more than one year after the date of the incurrence of such indebtedness in an amount not less than the total of the interest and principal payments in respect thereof required to be made during the next following fiscal year; and
6. To provide a fund for education in cooperation and for the dissemination of information concerning the effective use of electric energy and other services made available by the cooperative

shall, unless otherwise determined by a vote of the members, be distributed by the cooperative to its members as patronage refunds prorated in accordance with the patronage of the cooperative by the respective members paid for during such fiscal year. Nothing herein contained shall be construed to prohibit the payment by a cooperative of all or any part of its indebtedness prior to the date when the same shall become due.

[52] For more information, please see Section B-2, State Capital Credit Statutes in *Legal Issues Associated with Capital Credits*, available online at Cooperative.com.

Model B, 6 States

Arkansas, Mississippi, Nebraska, North Dakota, Pennsylvania, Texas

The revenues of a cooperative shall be devoted first to the payment of operating and maintenance expenses and the principal and interest on outstanding obligations, and thereafter to such reserves for improvement, new construction, depreciation, and contingencies as the board of directors may from time to time prescribe. Revenues not required for these purposes shall be returned from time to time to the members on a pro rata basis according to the amount of business done with each during the period either in cash, in abatement of current charges for electric energy, or otherwise as the board of directors determines. This return may be made by way of general rate reduction to members if the board of directors so elects.

Model C, 5 States

Alaska, Arizona, Kentucky, South Dakota, Virginia

A cooperative shall be operated on a nonprofit basis for the mutual benefit of its members and patrons. The bylaws of a cooperative or its contracts with members and patrons shall contain such provisions relative to the disposition of revenues and receipts as may be necessary and appropriate to establish and maintain its nonprofit and cooperative character.

In addition, the Model C is identical to section 23 of the Rural Electrification Administration's January 3, 1949, Uniform Electric Cooperative Act.

Other Approaches

Cooperative Act
California, Colorado, Hawaii, Iowa, Michigan, Minnesota, Nevada, Oregon, Utah, Washington, Wisconsin

Business Corporation Act
Delaware, New Jersey, West Virginia

Nonprofit Corporation Act
Idaho, Illinois, Ohio

Unique Electric Cooperative Act
Georgia, Indiana, Wyoming

Does Not Address Capital Credits
New Hampshire, North Carolina

No Electric Cooperatives
Connecticut, Massachusetts, Rhode Island

State Public Service Commissions

Cooperatives in 43 states are subject to some form of state regulation, including 24 states that exercise some degree of statutory authority over rates. State commissions may have regulations, policies or rulings affecting capital credits allocations and retirements. For example, the Arkansas Public Service Commission regulates Arkansas Electric Cooperative Corporation (AECC), a generation and transmission cooperative, and its 17 member distribution cooperatives. The commission requires three distribution cooperatives to make capital credits retirements to their consumer members any time they receive a capital credits refund from AECC. Requirements like this can affect financial planning, capital credits allocation procedures and other aspects of the distribution systems' operations.

In reviewing and revising capital credits policies, each system has an obligation to be aware of and comply with any state regulatory requirements.

ARE THE CO-OP'S CAPITAL CREDITS POLICIES IN COMPLIANCE WITH THE REQUIREMENTS OF LENDERS?

RUS

Since the early days of the rural electric program, RUS has maintained a philosophy that borrowers should achieve an adequate level of equity before retiring capital credits in order to ensure financial stability and the co-op's ability to repay its RUS loans. Recognizing that capital credits retirements can also be an important tool for ensuring the success of the cooperative, RUS has, over time, reduced the threshold requirements for retirement without prior approval.

RUS operational control regulations[53] grant prior automatic approval for capital credits retirements if the borrower's equity will be equal to or greater than 30 percent of total assets after the retirement. Otherwise, capital credits retirements require specific approval. This regulation is important because it provides a mechanism for borrowers subject to older loan documents to retire capital credits without obtaining additional approvals.

The current RUS loan contract[54] allows borrowers to retire capital credits if:

- The co-op's equity level will be equal to or greater than 30 percent of total assets after the retirement, or
- The co-op's equity level is greater than 20 percent and the total amount of all distributions during the calendar year are equal to or less than 25 percent of the prior year's margins.

Regardless of its equity level, a borrower also may make retirements to estates. Otherwise, a cooperative must obtain written approval to make capital credits retirements.

Borrowers who have failed to make payments on RUS debt or are otherwise in default of their loan documents with RUS are prohibited by both regulations and the current loan agreement from making capital credits retirements under any circumstances.

CFC

CFC's loan covenants allow borrowers to retire patronage capital provided equity will be equal to or greater than 20 percent after the retirement. If equity will be less than 20 percent, the borrower may retire up to 30 percent of the previous year's margins. Borrowers who are in default of payments or other loan agreement provisions may not retire capital credits.

[53] 7 C.F.R. 1717.67 (2004)
[54] Loan Contract with Distribution Borrowers, Sec. 6.8 Limitations on Distribution, 7 C.F.R. pt. 1718, subpt. C, app. A (2004)

ARE THE CO-OP'S CAPITAL CREDITS POLICIES COMPATIBLE WITH THE REQUIREMENTS OF THE FINANCIAL MARKETS?

The cooperative network's financial performance, collectively and individually, affects both access to and cost of funds from the financial markets. Whether a system approaches the markets directly or works through CFC—whose ability to raise funds depends directly on member performance—effective equity management contributes to a positive view from the financial community.

Fitch Ratings met with the task force to discuss its current analytical approach to evaluating electric cooperatives. The rating agency, which primarily rates G&T cooperatives, also discussed its views of distribution systems. Fitch takes a balanced approach in assessing key credit factors, looking for adequate financial strength for both the G&T cooperative and its member systems. In evaluating financial protection for lenders, it looks for:

- Adequate cash flow coverage,
- Strong equity position,
- Liquidity,
- A well-defined business plan, and
- An experienced management team and board.

Fitch does not rely solely on ratio targets to assign a rating category. However, for an A rating it would usually expect a G&T system to achieve:

- Equity of about 20 percent,
- Annual TIER and DSC of about 1.25, and
- Liquidity of about 60 days of operating expenses.

In terms of overall distribution system performance, assuming systems of reasonable quality with average credit features in terms of size, demographics, cost of power, retail rates and other factors, Fitch told the Capital Credits Task Force that the following ranges of financial ratios would be appropriate for an investment grade rating:

- 30 to 50 percent equity,
- Debt to funds available for debt service (FADS) of 10 or less,[55]
- Liquidity sufficient to meet 45 to 75 days of operating expenses, and
- Annual TIER and DSC of 1.5 to 2.0 or higher.

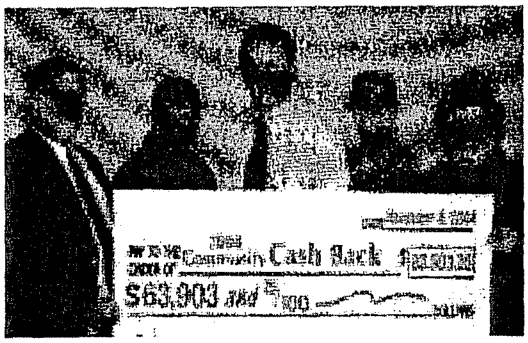
With regard to capital credits, Fitch says that the ability to be flexible in the timing and amount of payments made to customers is looked upon most favorably. Having control over the payments gives the systems the ability to build equity more quickly and provides another tool for managing liquidity over the longer term.

In developing its equity management plan, each system has to establish a target range for its performance based on its own operating environment.[56]

[55] FADS=operating income plus interest income plus depreciation
[56] Written comments from Fitch Ratings are available online at Cooperative.com.

Learn from Experience
Connexus Gives Capital Credits Cash Back to Members

Connexus Energy, Ramsey, Minnesota, uses capital credits retirements to connect with members and the local community under a program it calls Cash Back. "It's designed to be a central part of how customers relate to us," said Mike Bash, Connexus Chief Financial Officer. "We call it Cash Back to try to gain value recognition of why the cooperative way of doing business is a better deal."



(Left to Right): Michael McGlone, Salvation Army Heat Share; Karen Barber, American Red Cross; Mike Bash, Connexus Energy; Ann Olson Bercher, Minnesota Historical Society; Judy Karmack, Habitat for Humanity.

The original Connexus bylaws required the co-op to use the First-in, First-out (FIFO) method of retiring capital credits. "Only 12 percent of our customers were getting any cash back under the FIFO method," Bash said. "We wanted to maximize the number of current customers that were receiving capital credits."

Connexus amended its bylaws in 1994 to allow the board of directors to determine the method of capital credits retirement. In 2002, the co-op introduced Cash Back, a percentage-based retirement approach that ensures that virtually 100 percent of customers have the opportunity receive a capital credits retirement—Cash Back—or to donate the amount to one of four community organizations. "We are trying to balance getting money to current customers with acknowledging the obligation we have to former members to return their capital."

It takes about three months to carry out the Cash Back process. After the co-op completes the analysis detailing the Cash Back refunds, it sends a mailer to members notifying them of the amount and giving them the choice of the bill credit or donation. If the consumer chooses to keep the Cash Back, no action is needed. Consumers who choose the donation return a post card included with the mailer. Then the co-op credits bills and makes the contributions.

In 2004, 5,120 consumers donated almost $64,000 of more than $2.7 million in Cash Back payments to:

- Salvation Army Heat Share, a program that provides utility payment assistance;
- Habitat for Humanity, an organization that builds affordable houses;
- American Red Cross, a local chapter that provides humanitarian services in the community; and
- Minnesota Historical Society, proprietors of a local heritage farm.

These organizations were selected because their work relates to the co-op's role in the community. "The local symphony orchestra may be really important to the community, but it doesn't have a relationship to our role as a utility," Bash said. The co-op holds a ceremony to present the check to each organization, providing a photo opportunity that generates newspaper articles and positive press coverage. Member contributions made through Cash Back are tax-deductible.

The cooperative promotes the program through the mailer, the Connexus Web site, bill envelopes, the bill itself, newsletters and newspaper ads. "It is part of our year-round message that you get Cash Back from your electric utility. That is a distinguishing point, and the community giving fits with other things we do throughout the year," Bash said.

Chapter 5: Maximizing the Benefits of Capital Credits Decisions

Questions for board consideration

- What should a co-op know about its members?
- How can the co-op use capital credits retirements to communicate with members about the value of cooperative membership?
- What is the best time to issue capital credits retirements?
- What is the best method for issuing capital credits retirements?

Members, nonmembers and the public respond very favorably to the concept, principles and values that electric cooperatives offer consumers. In developing and implementing a capital credits policy, co-ops sometime overlook the opportunity to distribute capital credits payments in a way that will build member loyalty and educate consumers about the advantages of cooperative membership.

Learn from Experience
South Plains EC Tells the Cooperative Story

Whether it's through a promotional stuffer, a newspaper ad, or the local pages of its statewide magazine, South Plains Electric Cooperative in Lubbock, Texas, makes sure its 23,000 members understand the cooperative difference.

In September each year, just before their annual meeting, South Plains EC includes a catchy promotional stuffer with its mailing of capital credits checks to members. "We take this opportunity to differentiate our co-op from the other utility providers in our area," said South Plains EC Manager of Communications Lynn Simmons. "The stuffer is not highly technical—it mainly promotes how we operate differently as a co-op. The front side provides general information but members can flip it over and see enough detail that they can actually calculate their own retirement."

South Plains EC also educates its members about capital credits by providing comprehensive information in its annual report, which is part of the local pages in its Texas statewide magazine, *Texas Co-op Power.* "An entire page is devoted to explaining capital credits, why we have them, and how they make us different," Simmons said. "We also include a history of our allocations and refunds."

The co-op uses a FIFO/LIFO hybrid for retiring capital credits. "Last year we retired about a million dollars, representing half of our allocated margins for our most current year and half from previous years," said the co-op's Director of Finance and Administration Ronnie Rucker. "We've been experiencing heavy residential growth so many of our members have been members for less than five years. Many of them don't realize that they are part of a co-op. Usually within a year or two, a new member will receive their first capital credits check, and we feel this is a great way of demonstrating the benefits of belonging to South Plains."

South Plains also decided to reach out to both members and nonmembers to tell the cooperative story with a series of capital credits ads in 14 local newspapers. Each ad carried the same message but the photography was customized for the co-op's different types of members. "Our system is basically divided equally between residential, small commercial, irrigation and large industrial—in our case, oil companies," Simmons said. "As a Touchstone Energy co-op, we have very affordable access to a huge library of photos. We were able to have the photo in each ad speak directly to each of these members."

South Plains misses no opportunities to make sure that every member has the chance to learn what it means to be an owner of their electric utility. "Our goal is to consistently make ourselves visible as a community partner," Simmons said. "We just keep telling the story."

Recommendation

Communications Plan

Every cooperative should have a communications plan for educating members about capital credits and the cooperative's capital credits policies. Every director and each employee should understand the policy and be able to explain how it works and why it was adopted to members who have questions.

WHAT SHOULD A CO-OP KNOW ABOUT ITS MEMBERS?

Basic knowledge of the characteristics of its membership can help a co-op devise capital credits policies and communications programs that will maximize the benefit of capital credits retirements. Research shows that two of the most important characteristics are tenure of membership and age.

Tenure of Membership

According to the U.S. Census Bureau, 40.1 million U.S. residents—14.2 percent—moved between 2002 and 2003. While that is a decline from the 17 percent moving in 1994, it demonstrates that geographic mobility is an important aspect of American life.

The bureau also found that moving rates varied by the characteristics of the movers.

- Young adults had the highest moving rates with about one-third of 20-29-year olds moving—more than twice the rate of the population as a whole.
- Non-Hispanic whites were less mobile than other race and Hispanic-origin groups.
- Almost one-third of renters moved.
- People with income below poverty were more likely to move than those above poverty.

Fifty-nine percent of the moves were within the same county while 19 percent were to a different county within the same state; 19 percent were to a different state; and 3 percent were from abroad. In addition, the bureau found that 32.3 percent of the movers moved less than 50 miles. The median distance was 155.3 miles. The Midwest and Northeast regions experienced net migration losses of population while the South and the West had net migration gains.[57] While this information cannot be generally applied to an individual cooperative, it does confirm that many co-ops are likely to experience significant turnover every year. Census data is available in many forms down to individual blocks and can help a co-op understand the characteristics of its new members.

Age

Touchstone Energy recently completed a member attitude survey of the membership of five electric cooperatives. A substantial majority of those surveyed in all age groups agreed that it was an important value for cooperatives to give money back to their customers when operating revenues exceed costs. However, the number of those surveyed who strongly agreed that co-ops actually give money back to consumers varied substantially across age groups with younger members being much less likely to agree than older members. The results indicate an opportunity for these cooperatives to use capital credits refunds to demonstrate to younger members that cooperatives operate in accordance with their values.

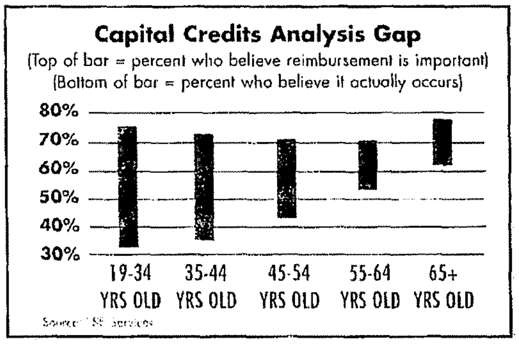
[57] U.S. Census Bureau, *Geographical Mobility: 2002 to 2003*, March 2004. Detailed census information is available at www.census.gov.

Research Shows Age Matters

Touchstone Energy recently commissioned TSE Services, a market research firm owned by North Carolina's electric cooperatives, to study consumer attitudes. The researchers presented the following statement to members of five electric cooperatives:

"Cooperatives give money back to their customers when revenues exceed costs."

A significant majority of consumers in all age groups ranked this as a very important value. When asked whether they agreed with the statement, the differences among age groups were striking. As few as 33 percent of members under age 35 strongly agreed with the statement, yet 75 percent of that group reported the attribute as very important. The results indicate a need to develop stronger connections with younger members.



The majority of consumers of all ages agree that it is important for cooperatives to give money back to consumers. However, younger consumers are much less likely to perceive that co-ops actually do return funds to consumers

In addition, a key drivers analysis done as part of this survey shows that giving money back to consumers contributes significantly to their perception of receiving a good value for the money they spend as well as their sense of membership. These perceptions have been shown to contribute strongly to high levels of satisfaction and customer loyalty.

While these results are specific to the original five participants, the results have been confirmed in efforts completed since the Touchstone study. Other co-ops may find it interesting to explore the attitudes of their younger members using similar methods.

Understanding population trends and viewpoints can help co-ops devise policies and communication materials that tie the co-op to its members more strongly. For example, co-ops with a growing Hispanic population may want to develop Spanish language materials. Co-ops with a very transient population may want to develop programs that target newcomers and younger members. The point is that co-ops must know their members in order to connect with them.

HOW CAN THE CO-OP USE CAPITAL CREDITS RETIREMENTS TO COMMUNICATE WITH MEMBERS ABOUT THE VALUE OF COOPERATIVE MEMBERSHIP?

Communicating with Different Audiences

A cooperative has to communicate its message about capital credits to several different audiences. The message should be tailored to fit the needs of those different audiences and timed for the maximum benefit.

Cooperative employees As soon as the co-op has determined the amount of capital credits it plans to retire, the manner and timetable, the cooperative should educate and inform the employees of the decision. It should be kept in mind that the employees are the frontline contact with the membership, and members will ask them questions regarding the co-op's capital credits retirement plans.

Neighboring cooperatives Once the cooperative has finalized its capital credits retirement strategy and plans, the cooperative should notify those electric cooperatives bordering their service areas and the statewide association of the board's decision. This advance notice will help them be prepared to respond to inquiries about their own equity/capitalization needs that their members might present upon learning of the neighboring cooperative's plan.

The cooperative's members The cooperative should carefully contemplate formulating answers to the questions consumers might ask. In addition, once the co-op announces the retirement of capital credits and distribution of checks, it should be prepared to handle a significant number of inquires from heirs and others who will claim to have the right to some former member capital credits. This also will include spouses of former members who have since divorced.

Media At the time the cooperative makes its initial announcement about retirement of capital credits, it should inform the media that cover the cooperative's service area about the amount of capital credits to be retired, the timetable and overall dollar amount of the retirement. The media, too, will need to be educated about capital credits and the value they bring to the membership and the cooperative business.

Public officials It is a good idea to alert state and federal legislative representatives about the cooperative's intentions. Such advance information can build a stronger awareness among these elected officials of the cooperative's commitment to the membership and community's economic well-being.

Studies have found that loyalty among consumers who identify with being a member of the cooperative is stronger than that of those who identify only with being a satisfied consumer. A member education and communication program that explains why co-ops are a different kind of utility and what benefits a consumer gains from being served by a cooperative is essential to fostering member identity. It is a long-term process that requires a long-term investment of time and energy as well as money. It also means that the co-op must operate in a way that embraces cooperative principles of member ownership, control and economic participation.

The act of distributing capital credits retirements offers an opportunity to address the special value of co-op membership. A well-designed capital credits retirement procedure will include a communications plan to help members understand what they are receiving. Capital credits are the members' investment in the cooperative. The investment has provided part of the capital needed to operate the co-op. By making that investment, members have reduced the cost of electricity for themselves and the other members. Capital credit retirements represent the return of that investment.

Communications materials should answer questions the member might have from the member's perspective, such as:

- What are capital credits?
- Why is it important for electric cooperatives to allocate and retire capital credits?
- How do capital credits benefit the cooperative and membership?
- Who receives capital credits allocations?
- When and how are capital credits returned?

Unclaimed capital credits may provide another opportunity to demonstrate the value of cooperative membership. If state laws allow the cooperative to retain unclaimed capital credits,[58] the co-op may designate a special purpose for these funds, such as a scholarship program for students from cooperative families.

[58] See page 59

Research Shows Members Unaware of Cooperative Difference

In May 2001 (during the California energy crisis), Peter D. Hart Research Associate, Inc., conducted seven focus group sessions in California, Texas, Kentucky and North Carolina, followed by a survey in June and July of more than 1,600 consumers, including co-op members and customers who purchase electricity from another type of supplier. The study was designed to elicit information that would help co-ops succeed in a competitive environment.

The study found that most American consumers were happy with their electric utility, regardless of the type of supplier, and that consumers believe that they can expect better service from a co-op. The study also found that consumers are not knowledgeable about the special nature of co-ops.

"The general public is largely unaware of the co-op option, and co-op members themselves are not tightly bonded to their co-op," the Hart report said. The report goes on to say, "Co-ops have two broad message themes to sustain themselves:

- Co-ops reliably provide energy at a reasonable cost.
- Co-ops are special organizations whose values mean better service for their members—the owners."

The researchers concluded that co-ops are doing well in making the first argument—but so are other electric utilities. They recommended that co-ops concentrate on the second message by building greater awareness of the values and heritage that make co-ops unique among electric providers.

While the project did not specifically address the issue of capital credits, a co-op can structure the capital credits retirement process to convey the message that the co-op is connected to the community and that it treats member-consumers with respect.

Source: Peter D. Hart Research Associates, Inc

Research Shows Fostering Member Identity Pays

The NRECA Market Research Services analyzed randomly selected samples of responses from 22,244 residential co-op members and 4,268 other residential electric customers aggregated from customer satisfaction and attitude studies conducted for co-ops from late fall 1999 through 2001. The consumers represented a diverse geographic area nationally. The purpose of the study was to determine whether there are benefits for electric service providers that are cooperatives and that are recognized by their customers as cooperatives.

The study found that co-op members who have some level of identity as member-owners of their co-op are more satisfied and loyal than both the members who do not have that sense of identity and members who don't know that their provider is a cooperative. This finding held true across the various demographic groups studied.

The study found that "Fostering member identity pays dividends in terms of satisfaction and loyalty to co-ops." The study concluded that having members who have an identity as member-owners pays dividends in satisfaction and loyalty.

While this study did not analyze capital credits specifically, capital credits are a valuable tool that can help forge a strong identity among consumers that they are indeed also members and owners of a cooperative that is responsive to their needs.

Source: NRECA Market Research Services

Learn from Experience
It's PEC Day in Oklahoma!

The annual meeting of Peoples Electric Cooperative is such a big event that the mayor of Ada, Oklahoma, declared it PEC Day. The 13,000-member co-op, which serves 11 counties in south central Oklahoma, draws an annual meeting attendance of 7,000 to 9,000 people, representing about 3,000 co-op members, every year.

How they do it? "It isn't easy—it's a lot of work!" said PEC Executive VP and General Manager Randy Ethridge. "The biggest factor is that we personally hand each member that attends the meeting their capital credits retirement check." Members travel as much as an hour each way to attend the meeting and receive their check.

With the help of most of its employees and police and other services provided by the city, PEC sponsors one of the biggest social gatherings of the fall season in the area. It's a family affair. Members and their guests enjoy live musical entertainment, prizes, arts and crafts booths, activities for the kids, and a smorgasbord of food provided by local vendors. And even though doors don't open until 9 a.m., members start lining up before 7:30 a.m. so they can register and pick up their share of the co-op's margins for the year.

"This event takes lots of planning and support from employees and the local community," Ethridge said. "We have 40 employees working 20 to 25 registration lines and registering members, thanking them for their support and handing them their checks. The logistics are mind boggling, but every year it works and we build member support and goodwill." Attendance continues to increase each year. Twenty years ago, the co-op had difficulty obtaining a required 5-percent quorum. Now, the meeting easily draws 25 to 30 percent of its membership. The co-op is confident that it will easily surpass a quorum at every annual meeting.

PEC uses a FIFO/percentage hybrid for retiring capital credits. Last year, the co-op's board decided to retire 20 percent of its current-year margins. "This amounted to an average check of $50 to $75 per member. Many local merchants offer special promotions on PEC Day to encourage members to spend their check right away and, in fact, we have so many people attending the meeting that we provide satellite transportation from many local shopping centers in the area," Ethridge said.

For this co-op, the annual meeting presents an opportunity to demonstrate to their members that they own the business and that it does make a difference.

WHAT IS THE BEST TIME TO ISSUE CAPITAL CREDITS RETIREMENTS?

Thoughtful timing and the method of the distribution can maximize the benefit of that communication. The best approach for an individual co-op depends on what it wants to accomplish, demographics and the size of the distributions. For example, the co-op may issue retirements at a time when members will appreciate extra money or when the cooperative wants to draw attention to cooperative principles, such as:

- In December before the holidays,
- At the end of the school year,
- During the peak season for utility bills,
- In conjunction with the annual meeting, or
- In October during National Cooperative Month.

Learn from Experience
Sioux Valley Energy Spreads Post-holiday Cheer with Bill Credits

Along with post-holiday bills, members of Sioux Valley Energy, Colman, South Dakota, find a pleasant surprise in their January mailboxes: a credit on their electric bill for their capital credits retirement. Some co-ops are afraid customers will not recognize refunds issued through bill credits, but that hasn't been a problem at Sioux Valley. To be sure customers don't miss it, the co-op includes a bright yellow bill insert explaining the retirement and what it represents. The refund also is publicized in the co-op's newsletter and statewide magazine. The co-op issues checks to consumers who have left the system.

Consumers like this approach, according to Eunice Bartels, board vice president. "We have had a good response to this method of retiring our capital credits," she said. The co-op likes the savings over issuing checks—more than $5,900 in postage in 2004 and additional savings as a result of not purchasing and processing checks.

The cooperative undertook a review of its capital management practices in 2002 to evaluate the impact of several factors. The co-op is experiencing growth and is also investing heavily in plant maintenance and line replacements. In addition, it wants to increase its equity level to help reduce the cost of borrowing funds. As a result, the board decided to reduce the amount set aside for annual capital credits retirements from 5 percent of total equity to 2.5 percent, including the estate retirements.

The co-op uses the FIFO/LIFO method for general retirements, retiring 70 percent of the oldest capital credits on the books and 30 percent of the most recent year allocated.

In 2004, Sioux Valley issued bill credits to 15,994 members and checks to 5,062 members for a total of $585,000 in general capital credits retirements. The co-op also retires capital credits to estates throughout the year.

The co-op evaluates its financial condition each year to determine whether capital credits retirements are prudent. "Repayment of capital credits will remain a year-to-year decision for the board," said Don Marker, General Manager. "We're happy that our strong financial condition made these retirements possible."

WHAT IS THE BEST METHOD FOR ISSUING CAPITAL CREDITS RETIREMENTS?

The co-op can issue the retirement as a check or bill credit. There are advantages and disadvantages to each approach. A check provides a more tangible demonstration of the return, but the administrative costs are higher. A bill credit may be overlooked on the bill, but it is a less costly approach.

Check or Bill Credit?

Capital credit retirements issued through either a check or a bill credit can provide an opportunity for positive interaction with members. The key is to have a well-thought-out plan for using the retirement to emphasize the benefits of cooperative membership.

Retirement Format	Advantages	Disadvantages
Check	• Tangible evidence of ownership • Marketing flexibility	• Higher administrative costs
Bill Credit	• Lower administrative costs	• Easy to overlook on bill • Must still send check to inactive patrons receiving a retirement

A co-op may decide to take different approaches with different customer classes. One way to focus attention on patronage capital retirements is to make a formal presentation of large capital credits checks, especially to visible institutions like schools or hospitals, and encourage media coverage. This can help maintain good relations with large accounts and also educate the membership as a whole.

A co-op's capital credits policy can be a valuable tool for building greater awareness of the values and heritage that make cooperatives unique among electric providers.

Chapter 6: Conclusion and Recommendations

The primary purpose of the task force is to educate boards of directors about current capital credits issues and encourage co-ops to review capital credits policies. While each cooperative has unique circumstances that affect its capital credits decisions, there are also common issues. In this report, the task force has provided alternative approaches to many of these issues. However, the task force recognizes that its work would not be complete if it did not make recommendations on issues when it believes that the appropriate action is clear and applicable in most situations. It is the task force's hope that these recommendations will help co-ops meet capital credits obligations in a way that strengthens the value of all cooperatives.

WHAT ARE THE RECOMMENDATIONS OF THE CAPITAL CREDITS TASK FORCE?

While there are many aspects to the process of developing a capital credits policy, the board of directors has two basic responsibilities: to establish strategic goals for the co-op's capital credits policy and to determine the techniques for allocating, retiring, refunding and communicating with members about capital credits that will be most effective in helping the co-op achieve these goals while complying with applicable laws, regulations and the co-op's own bylaws. The task force has adopted recommendations to address each of these areas.

Strategic Goals

A Board-Approved Policy: Every electric cooperative should have a policy for annually allocating capital credits and, subject to the board of directors' discretion and the cooperative's financial condition, annually retiring capital credits.

Members have an economic stake in the cooperative. Through rates, they invest funds in the cooperative that enable them to receive services that might not otherwise be available. The return of that investment through the allocation and retirement of capital credits is one of the concepts that defines a cooperative and distinguishes it from another form of business. It also helps to ensure that each generation of consumers provides its own capital. Various federal and state laws and regulations as well as many cooperatives' articles of incorporation and bylaws also address capital credits requirements.

The 1976 Capital Credits Study Committee recommended that electric cooperatives retire capital credits: "In order to develop a sense of ownership on the part of the members and to reward our members for the capital they contribute, capital credits should be retired even though the amounts in any given year may be relatively small."[59]

That statement continues to be true. Capital credits provide a tangible demonstration of the value of the cooperative form of organization and of the benefits of cooperative membership.

A checklist to assist boards in considering the issues that must be addressed in establishing a capital credits policy is included in Appendix 3.

Equity Management Plan: Every electric cooperative should develop and implement an equity management plan that supports its capital credits policy based on the co-op's equity and debt requirements, financial performance and competitive situation. The equity management plan should include rates that will generate adequate cash to provide capital credits retirements.

Planning for capital credits retirements is a financial responsibility just like planning to repay debt, build equity and finance capital additions. An equity management plan provides the financial foundation that the board needs to balance debt and equity effectively to meet a variety of financial needs and criteria, including retiring capital credits.

The equity management plan guides the board in making decisions about rates and other issues that will allow the cooperative to generate adequate capital to fund growth and other needs without retaining member funds longer than is necessary or in amounts in excess of its needs.

[59] *Final Report and Recommendations*, Capital Credits Study Committee, February 1976

Adequate Equity Level: Each electric cooperative should seek to maintain an equity level adequate to retire capital credits on an annual basis and meet the goals and requirements of its equity management plan. The task force suggests that a reasonable equity level for most distribution systems is in the range of 30 to 50 percent, depending on the cooperative's financial and competitive situation.

A cooperative's equity level is one of the key indicators of financial health, and maintaining an appropriate equity level is a primary goal of the equity management plan. It is also important for the cooperative network as a whole to continue to achieve a strong financial performance in order to maintain access to adequate amounts of capital at a reasonable cost. While most discussions focus on the need to maintain minimum equity levels—the Capital Credits Study Committee recommended a minimum equity level of 30 percent—it is also possible for a cooperative to create and retain excessive equity. The financial community generally equates equity in the 30 to 50 percent range with an investment-grade rating for distribution systems. The task force believes that this is an appropriate range for the equity level of most electric distribution cooperatives.

Permanent Equity: The development of permanent equity should not be a goal of a cooperative's capital credits policy. Any advantages of permanent equity, such as building a cooperative's equity level or developing reserves, can be achieved in more direct ways that do not involve the same tax, takeover or other risks inherent in a policy of permanent equity.

Some tax advisers have suggested that cooperatives should create a pool of permanent equity that is not allocated to members as capital credits. Permanent equity may be created as a consequence of a business decision made for other reasons, such as discounting special capital credits retirements to estates. Beyond that, some cooperatives have considered adopting a goal of accruing permanent equity as a matter of policy through discounting general retirements, retaining non-patronage-sourced margins or other means.

Those who favor permanent equity say that it can provide permanent reserves, allow the co-op to rotate remaining patronage capital more quickly and improve the co-op's credit profile, among other suggested benefits. Any advantages of permanent equity, however, can be achieved more easily and with less expense through careful planning and execution of the co-op's equity management plan. Adopting a goal of creating permanent equity requires a fundamental change in the interpretation of cooperative philosophy and should be avoided.

Allocating Capital Credits

Member Notification: Cooperatives should notify members in writing of the dollar amount of annual capital credits allocations.

Depending on individual circumstances and tax status, a cooperative may or may not be legally required to notify each member of the specific amount allocated to the individual capital credits account each year.

Each member is an owner of the cooperative; each member supports the cooperative financially through the rates paid for electricity and other services; and each member is entitled to capital credits. It is consistent with cooperative principles, and common sense, that each member is entitled to know the amount of capital credits allocated each year, whether or not there is a binding legal requirement to that effect.

Contractual Forfeiture: Electric cooperatives should not enter contracts that require members to forfeit the right to capital credits in return for other considerations, such as reduced rates.

Contractual forfeiture of capital credits is inconsistent with cooperative principles and questionable from a tax perspective. Since similar results can be achieved through other means, the practice should be avoided.

Retiring Capital Credits

Selecting Retirement Method Based on Goals: Each cooperative should choose a retirement method that will help the co-op achieve its goals, recognizing the effect the tenure and age of its members has on the perception of the value of membership in the cooperative. The task force strongly recommends that each cooperative know the percentage of its current membership receiving a capital credits retirement each year and seek to maximize that percentage.

Historically, the first-in, first-out (FIFO) method has been the most commonly used capital credits retirement method. The 1976 Capital Credits Study Committee recommended that cooperatives consider adopting the percentage method, citing the need to involve current members more fully in the capital credits process.

Today, the Capital Credits Task Force recognizes that the demographics of members served vary widely among electric cooperatives. Some cooperatives serve a relatively stable membership while others are experiencing a high rate of turnover. Research has shown that tenure and age affect the way members perceive the value of cooperative membership differently. The capital credits retirement method can contribute to or reduce perceptual differences.

Rather than recommend a one-size-fits-all approach, the task force suggests that each cooperative establish specific goals for capital credits retirements based on its unique member demographics, operating characteristics and legal requirements. The board should adopt a retirement method that will achieve those goals. For example, if the goal is to reward long-term patronage, the FIFO method may be the best approach. If the goal is to educate newer members in the value of the cooperative form of organization, the percentage method may be the best choice. If the cooperative wants to be sure as many members as possible receive a capital credits refund, it may prefer a hybrid method.

What is most important is that each system retires capital credits in a manner that maximizes the value to its membership.

Discount Special, Not General, Retirements: If an electric cooperative chooses to make special retirements, such as retirements to estates, the amount of the retirement should be discounted to reflect the time value of money. Cooperatives should not offer discounted general retirements.

Many cooperatives make special retirements of capital credits in recognition of unusual circumstances, such as the death of a member. Some cooperatives also offer general retirements at a discount, either in order to create permanent equity or to reduce record-keeping requirements for members leaving the system.

Early retirements allow the cooperative to make a payment sooner than it otherwise would. There is a real cost to the other members of the cooperative to do that, and there is a benefit to the member to receive money sooner than the member would otherwise. It also may be unfair to some members to return investments in the cooperative to other members out of order. Discounting to reflect the time value of money is a way to balance the impact of special retirements so that no one experiences undue financial benefit or harm. Keep in mind that the Internal Revenue Service position with respect to discounts is still evolving, and discounting may result in non-member income.

The task force recognizes that special retirements are a well-established aspect of the capital credits policies of many cooperatives. Discounting those retirements preserves fairness to all members. Since the total amount of special retirements in a given year is likely to be small, the potential benefit to both the cooperative and member, for example, being able to close an estate and remove an account from the co-op's books, is likely to outweigh the potential risks.

Making general retirements at a discount is not an established practice for most systems. It is difficult to administer such a practice fairly while maintaining a strong financial performance, and it may put the cooperative at risk for failing the 85-percent test. The task force believes that cooperatives should not make general retirements at a discount. If a system wishes to do so, the task force recommends that it seek a private-letter ruling with regard to the impact on non-member income before implementing such a policy.

Recommended Discount Rate: If a cooperative makes discounted capital credits retirements, the task force suggests that the discount rate selected should be based on the cooperative's weighted cost of capital, which includes the cost of equity and the cost of debt.

It is important that discounted capital credits retirements be made in a fair and equitable manner. Choosing an appropriate discount rate is the key to making that happen. Too high a rate penalizes the member. Too low a rate penalizes the cooperative and its remaining members. There is no one standard that is appropriate for every cooperative in every situation. Rather, an individual board should be able to justify and verify the rate it selects. Since rates change often, the chosen rate should be reviewed and adjusted periodically to ensure that it continues to be fair.

Age of Members: Electric cooperatives should not make special capital credits retirements based solely on the age of the member.

Retiring capital credits to members who reach a certain age may discriminate against other members unless a discount is applied and may become a financial burden to other members as the membership ages. If the co-op receives federal financial assistance from RUS or otherwise, the retirement may violate the Age Discrimination Act of 1975. If the co-op does not receive federal financial assistance, there does not appear to be a general prohibition against the practice. It is, however, inconsistent with cooperative principles. Likewise, depending on the outcome of current deliberations, the practice may result in capital credits being classified as a liability under FAS 150.

Compliance

Director Flexibility and Discretion: Every electric cooperative should review its bylaws, state laws and other applicable governing factors in terms of the impact on capital credits policies. If a cooperative's bylaws do not permit the board to exercise sufficient discretion regarding the method for allocating or retiring capital credits, the cooperative should consider seeking changes to give directors such flexibility in determining capital credits policies.

Cooperatives have experienced many changes over time and will undoubtedly experience more changes in the future. It is impossible to anticipate what all of these changes might be, but it is possible to prepare for them by providing the board of directors with the greatest amount of flexibility possible in making future decisions. For example, FAS 150, if adopted as proposed in May 2003, would change accounting practices that have been followed for decades in a way that could have a substantial negative impact on the equity levels of systems that have mandatory provisions for the method of retiring capital credits. Adopting a more flexible approach now could help systems avoid this problem and others in the future.

Maximizing the Benefits of Capital Credits Decisions

Communications Plan: Every cooperative should have a communications plan for educating members about capital credits and the cooperative's capital credits policies. Every director and each employee should understand the policy and be able to explain how it works and why it was adopted to members who have questions.

A co-op's capital credits policy helps the co-op operate in accordance with cooperative principles and comply with applicable state and federal laws along with the co-op's articles of incorporation and bylaws. It also provides an opportunity to connect with members in a way that builds member loyalty and educates consumers about the advantages of cooperative membership. Communicating with members about capital credits allows the cooperative to explain why the co-op is a different kind of utility and the benefits the consumer gains from being a part of the cooperative.

Appendix 1: Online Resources

Users can access the following resources online at Cooperative.com:

Announcement 96-24, Exempt Organizations, Proposed Examination Guidelines Regarding Rural Electric Cooperatives
Guidelines for Exempt Organizations Internal Revenue Agents to use during the examinations of rural electric cooperatives

Capital Credits Retirement Procedures, The Report of the Capital Credits Retirement Procedures Task Force, August 1980
Specific recommendations related to administering capital credits policies

Code of Federal Regulations 7 CFR 1767 Accounting Requirements for RUS Electric Borrowers
Uniform System of Accounts for RUS borrowers

Comments of Fitch Ratings
Summary of Fitch presentation to Capital Credits Task Force, including criteria for assessing key credit factors

Distribution Cooperative Survey Results
Summary of capital credits practices of 509 distribution cooperatives

Final Report and Recommendations, Capital Credits Study Committee, February 1976
First document to address legal, accounting and philosophical aspects of equity management, capital credits allocations and capital credits retirements in a comprehensive manner

G&T Cooperative Survey Results
Summary of capital credits practices of 30 G&T cooperatives

History of Internal Revenue Service Rulings
Washington Utility Group summary of IRS rulings related to discounting capital credits retirements

Internal Revenue Code (IRC) Section 501(c)(12)
Regulation that grants tax-exempt status to electric cooperatives, among others, and establishes criteria for tax-exemption

IRS Publication 557, Tax-Exempt Status for Your Organization
Rules and procedures for organizations that seek tax-exempt status under Section 501(c)(12)

Legal Issues Associated with Capital Credits
Extensive review of legal rights and obligations of co-ops and their patrons regarding capital credits, including citations

Michael Seto and Cheryl Chasin, *General Survey of IRC 501(c)(12) Cooperatives and Examination of Current Issues*
General cooperative principles and rules governing IRC 501(c)(12) cooperatives, the history of IRC 501(c)(12) and other requirements that affect operations of IRC 501(c)(12) cooperatives, and current issues.

Private Letter Ruling on Allocation of Multiple Services
Text of letter accepting co-op's plan to form three operating units to provide electric, gas and telecom services

Trends in Equity and Capital Credits Retirements
Discussion of trends in co-op equity and capital credits retirement levels

Update on SFAS 150
The current status of the Financial Accounting Standards Board's actions regarding proposed standard governing treatment of equity and liabilities, including capital credits

Users also can find links to the following resources on Cooperative.com:

AICPA Audit and Accounting Guide. *Audits of Agricultural Producers and Agricultural Cooperatives*
Financial reporting model and guidance on generally accepted accounting procedures

U.S. Census Data
Available data to assist with market research and demographics studies

United States Postal Service Address Management Services
USPS provides a variety of services to assist users in tracking customer address changes

Appendix 2: Frequently Asked Questions

This document is generic in nature, intended to assist board members and staff in answering basic member questions about capital credits and the co-op's capital credits policy. Individual cooperatives wishing to use these questions and answers should first modify them to reflect the specific policies of the cooperative.

What is a cooperative?
A cooperative is a business that is owned and controlled by the people who use its services.

What are capital credits?
A cooperative does not earn profits in the sense that other businesses do. Instead, any margins, or revenues remaining after all expenses have been paid, are returned to the members in proportion to their usage of the co-op's services through capital credits allocations and retirements. Capital credits represent each member's share of the cooperative's margins and ownership of the co-op.

Electric cooperatives have returned nearly $6 billion to their owners over the years and in 2003 returned more than $500 million in capital credits.

What do cooperatives do with capital credits?
Every business needs to maintain a suitable balance between debt and equity to ensure its financial health and stability. Capital credits are the most significant source of equity for most electric cooperatives. Equity is used to help meet the expenses of the co-op, such as paying for new equipment to serve members and repaying debt. Capital credits help keep rates at a competitive level by reducing the amount of funds that must be borrowed.

How does the cooperative determine who receives capital credits?
Capital credits are allocated to each member of the cooperative every year based on participation in the cooperative. The board of directors determines the basis for the allocation. Frequently, the allocations are based on such measures as the total dollar amount of services purchased or kwh of electricity consumed.

How does the cooperative notify members about capital credits allocations and retirements?
Most cooperatives notify members of annual capital credits allocations through a letter, a message on each member's bill, the co-op's Web site or other methods.

How are capital credits disbursed?
Each year the board of directors determines whether the co-op's financial position permits the return, or retirement, of capital credits and, if so, what amount of capital credits will be retired.

The board also decides the method for determining which capital credits are returned. For example, many cooperatives retire capital credits using the First-in, First-out, or FIFO, method. That means that the capital credits that have been invested in the cooperative for the longest period of time are returned to members first. A cooperative using the FIFO method might return capital credits allocated in 1984 to members in 2004.

Other co-ops retire capital credits using the percentage method. That means that a portion of the total amount of capital credits allocated to a member over time are returned each year.

Another way to retire capital credits is to use a combination of methods, such as the FIFO/Percentage hybrid, which makes part of the capital credits retirement on the FIFO basis and part using the percentage method. The Last-in, First-out, or LIFO, method, which repays capital credits that have been invested in the cooperative for the shortest period of time first, is rarely used alone, but the FIFO/LIFO hybrid is a popular approach.

The approach that works best for an individual system depends on a number of factors, including the age and tenure of its membership.

Do members receive interest on capital credits?
Some cooperatives are prohibited from paying interest on capital credits by their articles of incorporation or other legal documents. Whether that is the case, co-ops do not pay interest on capital credits, because the money to pay that interest would have to be collected from members through higher rates.

What happens to a member's capital credits if the member moves away from the system?
A member who terminates service no longer receives additional capital credits allocations. The balance in the member's capital credits account is maintained until it is retired in full.

It usually is the member's responsibility to notify the co-op of any changes in address so that the member can be located when it is time for the co-op to retire capital credits allocated to the member's account.

What happens to a member's capital credits if the member dies?
Capital credits in the member's account belong to the member's estate. In order to assist the member's heirs in closing the estate, some co-ops offer a special capital credits retirement of the outstanding balance of the deceased member's capital credits account, often at a discount.

Why are some capital credits retirements discounted?
In the interest of fairness to all members, some co-ops discount capital credits retirements, such as special retirements to estates, to reflect the net present value of making a capital credits retirement now that would otherwise be made at a later date. The smaller amount received today, if invested until the normal retirement date, would be equal to the normal retirement amount.

Why does the co-op not charge lower rates instead of retaining capital credits?
The board of directors has a fiscal responsibility to maintain the financial integrity of the cooperative in a way that provides competitive rates and allows the return of capital credits to members. Having a sound equity management plan and a commitment to serving the members are key to achieving this.

Does the member have to report capital credits on tax returns?
Capital credits are a return of money paid for electricity in a previous year and are generally not taxable income for residential consumers. Commercial and industrial consumers should discuss any capital credits retirements with their tax advisers.

Appendix 3: Capital Credits Decision Checklist

must be addressed in establishing a capital credits policy.

Board Policy on Capital Credits

- ❑ Does the cooperative have a comprehensive written capital credits policy approved by the board of directors?
- ❑ Is the policy written so that it can be easily understood by the board, management, staff, members and others?
- ❑ Does the policy include:
  - ❑ A clear, concise statement of objectives?
  - ❑ A clear, concise policy statement?
  - ❑ The board's expectations as what the policy will achieve?
  - ❑ Any limits in terms of time, process or other constraints on the implementation of the policy?
  - ❑ Direction as to responsibility for enforcement and evaluation of the policy?
- ❑ Does the policy include the date of approval, any revisions and scheduled review?
- ❑ Is the policy readily available to those who need it?
- ❑ Does the board review the policy on an annual basis?
- ❑ Does the policy clearly state the co-op's objectives regarding capital credits?
- ❑ Does the policy establish a desired equity target?
- ❑ Does the policy provide for annual review and approval of allocations and retirements by the board?

Allocating Capital Credits

- ❑ What margin components will be allocated as capital credits?
  - ❑ Patronage-source income only (operating margins and other income as determined by tax regulations)
  - ❑ All income, including patronage-sourced and non-patronage-sourced income
- ❑ Will the co-op make separate allocations for some patronage-sourced margins?
  - ❑ Capital credit allocations received from a G&T
  - ❑ Capital credit allocations received from other affiliated organizations
  - ❑ Other (specify) ________________________
- ❑ Will the co-op allocate margins to customers in different classes based on the contribution of each class to the co-op's margins?
- ❑ On what basis will margins be allocated?
  - ❑ Dollar amount of services purchased
  - ❑ Quantity of kwh purchased
  - ❑ Dollar contribution to margin
  - ❑ Other (specify) ________________________
- ❑ For cooperatives offering multiple services, is the co-op required to allocate margins from

these services separately?
- ❑ If so, is the cooperative in compliance with this requirement?

❑ How will the co-op notify members of the amount of capital credits allocations each year?
- ❑ U.S. mail
- ❑ Message on bill
- ❑ Electronically through online bill payment
- ❑ Combination of methods (specify) ______________________
- ❑ Other (specify)________________________

Retiring Capital Credits

❑ What amount of capital credits will the co-op retire this year?
- ❑ What level of capital credits retirements is supported by the co-op's equity management plan and financial forecast?
- ❑ Is the co-op's financial performance adequate to retire capital credits?

❑ What retirement method will the co-op use?
- ❑ What are the co-op's objectives for maximizing the value of capital credits retirements?
- ❑ What is the age distribution of the co-op's members?
- ❑ What is the tenure of the co-op's members?
- ❑ What are the members' expectations regarding capital credits retirements?
- ❑ What percentage of current members will receive a capital credits retirement?
- ❑ Which retirement method best meets the co-op's objectives for maximizing the value of capital credits retirements?
  - ❑ First-in, First-out (FIFO)
  - ❑ Percentage of total allocated capital credits
  - ❑ Hybrid of FIFO and percentage method
  - ❑ Hybrid of FIFO and Last-in, First-out (LIFO) method
  - ❑ Other (specify)________________________

❑ Should the cooperative make special capital credits retirements?
- ❑ What are the objectives of the special retirement?
- ❑ Accommodate the estates of deceased members?
- ❑ Other (specify)________________________

❑ Should the co-op discount special capital credits retirements?
- ❑ Should discounted capital credits retirements be voluntary or mandatory?
- ❑ What discount rate should the co-op use?

Maximizing the Value of Capital Credits Retirements

- ❑ What payment method for capital credits retirements provides the greatest value, considering the costs and benefits?
  - ❑ Check
  - ❑ Bill credit
  - ❑ Should the co-op set a minimum amount for retirement by check?
- ❑ What is the best time to issue capital credits refunds?
  - ❑ Around the holidays
  - ❑ At the end of the school year
  - ❑ At the annual meeting
  - ❑ During the peak season for utility bills
  - ❑ Other (specify)____________________
- ❑ What is the co-op's plan for educating members about capital credits and the co-op's capital credits policies?
  - ❑ Can all of the co-op's board members explain the co-op's capital credits policy and answer specific questions from consumers?
  - ❑ Can all of the co-op's employees explain the co-op's capital credits policy and answer specific questions from consumers?
  - ❑ Does the co-op present information about capital credits on its Web site and in its newsletter or other publications?
- ❑ How can the co-op use unclaimed capital credits to enhance the perception of the co-op and contribute to the community?

Compliance Issues

- ❑ Is the co-op in compliance with the requirements of applicable authorities governing capital credits retirements?
  - ❑ Federal laws
  - ❑ State laws
  - ❑ Articles of incorporation
  - ❑ Mortgage covenants
  - ❑ Bylaws
- ❑ Is the co-op in compliance with applicable accounting standards?
- ❑ Are the cooperative's current practices in compliance with its capital credits policy?

Appendix 4: Sample Bylaws

The following sample electric cooperative capital credits bylaws address the allocation, notification, assignment, and retirement of capital credits. They do not address other bylaws impacting or involving capital credits, like bylaws governing dissolution, etc.

These sample bylaws are a guide and resource to assist electric cooperatives in adopting or amending capital credits bylaws. ***They are not "model" bylaws to be adopted without extensive review, consideration, and revision.***

These sample bylaws are based upon federal cooperative tax law and general state cooperative law. They are not based upon the law of any particular state. These sample bylaws are drafted primarily for an electric distribution cooperative that is exempt from federal income taxation, with some flexibility for fiscal years during which the cooperative becomes nonexempt, or taxable. ***Before considering, adopting, or amending capital credits bylaws, an electric cooperative should consult with its attorney and tax consultant.***

Because state laws vary, and because electric cooperatives may reach different policy decisions and have different tax considerations, these sample bylaws include alternative or optional language that is *[italicized and bracketed]*. As used in these sample bylaws, "Cooperative" means the electric cooperative and "Board" means the electric cooperative's board of directors or trustees.

SAMPLE CAPITAL CREDITS BYLAW

Section X.XX – Allocation of Capital Credits. The term "patron" means, during a fiscal year: (1) a member of the Cooperative and (2) any other individual or entity purchasing a good or service from the Cooperative to whom the Cooperative is obligated to allocate capital credits, which obligation existed before the Cooperative received payment for the good or service.[1]

For each good or service provided by the Cooperative on a cooperative basis during a fiscal year, the Cooperative shall equitably allocate to each patron, in proportion to the quantity or value of the good or service purchased by the patron during the fiscal year,[2] the Cooperative's patronage earnings from providing the good or service during the fiscal year, which is the amount by which the Cooperative's patronage sourced revenues from providing the good or service exceed the Cooperative's patronage sourced expenses[3] of providing the good or service, all as determined under federal cooperative tax law.[4] If the Cooperative's patronage sourced expenses of providing the good or service during the fiscal year exceed the Cooperative's patronage sourced revenues from providing the good or service during the fiscal year, all as determined under federal cooperative tax law, then the Cooperative shall: (1) allocate this patronage loss to each patron in proportion to the quantity or value of the good or service purchased by the patron during the fiscal year;[5] (2) offset this patronage loss with the Cooperative's patronage earnings from providing the good or service during the most recent past fiscal year(s) or the next succeeding future fiscal year(s); or (3) offset this patronage loss first with the Cooperative's nonpatronage earnings during the current fiscal year, second with the Cooperative's unallocated nonpatronage earnings during any past fiscal year(s), and third with the Cooperative's nonpatronage earnings during any future fiscal year(s).

[1] This definition of "patron" is based upon federal cooperative tax law. Through contract or otherwise, a non-member customer may be legally entitled to an allocation of capital credits.

[2] As allowed by state cooperative law, an electric cooperative may revise this and similar clauses to add the following italicized language to read, "in proportion to the quantity or value of the good or service purchased by the patron during the fiscal year *and timely paid for* by the patron."

[3] As allowed by state cooperative law, and consistent with federal cooperative tax law, an electric cooperative may further define the "expenses" referenced in these sample bylaws.

[4] Patronage earnings generally include all operating income. They also include some nonoperating income, like interest earned on reasonable amounts of working capital and possibly the gain on the sale of capital assets. Under federal cooperative tax law, an exempt electric cooperative is obligated to allocate operating margins only, instead of all patronage earnings. Under federal cooperative tax law, other exempt cooperatives, as well as nonexempt cooperatives, are obligated or encouraged to allocate all patronage earnings, instead of operating margins only. For consistency and simplicity, and to mitigate the adverse tax consequences of an electric cooperative temporarily or permanently losing its exemption, these sample bylaws require the allocation of all patronage earnings, instead of operating margins only. An exempt electric cooperative, however, may choose to require the allocation of operating margins only, instead of all patronage earnings.

[5] The Rural Utilities Service prohibits distribution borrowers from allocating operating losses.

[For each fiscal year, the Cooperative shall equitably allocate to each patron, in proportion to the quantity or value of goods or services purchased by the patron during the fiscal year, the Cooperative's nonpatronage earnings, which is the amount by which the Cooperative's nonpatronage sourced revenues during the fiscal year exceed the Cooperative's nonpatronage sourced expenses during the fiscal year, less any amount needed to offset a patronage loss. OR As determined by the Board, the Cooperative may use, retain, or equitably allocate the Cooperative's nonpatronage earnings, which is the amount by which the Cooperative's nonpatronage sourced revenues during a fiscal year exceed the Cooperative's nonpatronage sourced expenses during the fiscal year, less any amount needed to offset a patronage loss.[6]] [If the Cooperative's nonpatronage sourced expenses during the fiscal year exceed the Cooperative's nonpatronage sourced revenues during the fiscal year, then the Cooperative shall allocate this nonpatronage loss to each patron in proportion to the quantity or value of goods or services purchased by the patron during the fiscal year or offset this nonpatronage loss with the Cooperative's nonpatronage earnings during any fiscal year.]

For each amount allocated to a patron, the patron shall contribute a corresponding amount to the Cooperative as capital. The Cooperative shall credit all capital contributions from a patron to a capital account for the patron. The Cooperative shall maintain books and records reflecting the capital contributed by each patron. At the time of receipt by the Cooperative, each capital contribution will be treated as though the Cooperative paid the allocated amount to the patron in cash pursuant to a pre-existing legal obligation and the patron contributed the corresponding amount to the Cooperative as capital. The term "capital credits" means the amounts allocated to a patron and contributed by the patron to the Cooperative as capital.

Consistent with this bylaw, the allocation of capital credits is in the discretion of the Board and the Board shall determine the manner, method, and timing of allocating capital credits. As reasonable and fair, the Cooperative may allocate capital credits to classes of similarly situated patrons under different manners, methods, and timing, provided the Cooperative allocates capital credits to similarly situated patrons under the same manner, method, and timing. The Cooperative may use or invest unretired capital credits as determined by the Board.

If the Cooperative is a member, patron, or owner of an entity from which the Cooperative purchases a good or service used by the Cooperative in providing a good or service and from which the Cooperative is allocated a capital credits or similar amount, then, as determined by the Board and consistent with this bylaw, the Cooperative may separately identify and allocate to the Cooperative's patrons this capital credits or similar amount allocated by the entity.

Upon the Cooperative receiving written notice and sufficient proof of the death of a spouse in a joint membership, the Cooperative shall assign and transfer to the surviving spouse the capital credits allocated, or to be allocated, to the joint membership. Upon the Cooperative receiving written notice and sufficient proof of the dissolution of marriage between spouses in a joint membership, and unless otherwise instructed by a court or administrative body of competent jurisdiction, the Cooperative shall assign and transfer to each spouse one-half (1/2) of the capital credits allocated to the joint membership.[7]

[To secure a patron's obligation to pay all amounts owed to the Cooperative, including any compounded interest and late payment fee, and in return for the Cooperative providing a good or service to the patron, the Cooperative has a security interest in capital credits allocated to the patron. The patron authorizes the Cooperative to perfect this security interest by filing a financing statement.[8]]

[6] State cooperative law may require a cooperative to allocate nonpatronage earnings. Federal cooperative tax law, however, does not require a cooperative to allocate nonpatronage earnings.

[7] If state law and an electric cooperative's bylaws permit a *joint membership comprised of individuals other than spouses*, then the cooperative must revise this bylaw accordingly.

[8] To be enforceable, a patron must usually sign or otherwise authenticate this security interest. To best protect and prioritize this security interest, an electric cooperative should perfect it, usually by filing a financing statement. State law usually includes detailed provisions governing the creation, enforcement, and perfection of security interests

Section X.XX – Notification and Assignment of Capital Credits. Within a reasonable time following the end of each fiscal year, the Cooperative *[shall OR may]* notify each patron in writing of the stated dollar amount of capital credits allocated to the patron for the preceding fiscal year.[9] Unless the Board determines otherwise, and unless these bylaws provide otherwise, the Cooperative may assign or transfer a patron's capital credits only if:
(1) the Cooperative receives a written request signed by the patron to assign or transfer the capital credits, (2) the patron and the assignee or transferee comply with all reasonable requirements specified by the Cooperative, and (3) the Board approves the assignment or transfer.

Section X.XX – Retirement of Capital Credits. At any time before the Cooperative's dissolution, liquidation, or other cessation of existence, the Cooperative may generally retire and pay some or all capital credits allocated to patrons and former patrons.

Upon the death of an individual patron or former patron, upon receiving a written request from the deceased individual's legal representative, and under terms and conditions agreed upon by the Cooperative and the deceased individual's legal representative, the Cooperative may specially retire some or all capital credits allocated to the individual. *[Upon the dissolution, liquidation, or other cessation of existence of an entity patron or former patron, upon receiving a written request from the former entity's legal representative, and under terms and conditions agreed upon by the Cooperative and the former entity's legal representative, the Cooperative may specially retire and pay some or all capital credits allocated to the former entity. OR Upon the dissolution, liquidation, or other cessation of existence of an entity patron or former patron, the Cooperative may not specially retire and pay capital credits allocated to the former entity.] [Upon the reorganization, merger, or consolidation of an entity patron or former patron, upon receiving a written request from the entity or the entity's legal representative, and under terms and conditions agreed upon by the Cooperative and the entity or the entity's legal representative, the Cooperative may specially retire and pay some or all capital credits allocated to the entity. OR Upon the reorganization, merger, or consolidation of an entity patron or former patron, the Cooperative may not specially retire and pay capital credits allocated to the entity.]*

If the Cooperative separately identified and allocated capital credits representing capital credits or similar amounts allocated to the Cooperative by an entity in which the Cooperative is or was a member, patron, or owner, then the Cooperative shall retire and pay these capital credits *[before or after OR after]* the entity retires and pays the capital credits or similar amounts to the Cooperative.

After retiring capital credits allocated to a patron or former patron, the Cooperative may recoup, offset, or setoff any amount owed to the Cooperative by the patron or former patron, including any compounded interest and late payment fee, by reducing the amount of retired capital credits paid to the patron or former patron by the amount owed.

The Cooperative may retire and pay capital credits only if the Board determines that the retirement and payment will not adversely impact the Cooperative's financial condition. Consistent with this bylaw, the retirement and payment of capital credits are in the discretion of the Board and the Board shall determine the manner, method, and timing of retiring and paying capital credits. As reasonable and fair, the Cooperative may retire and pay capital credits to classes of similarly situated patrons under different manners, methods, and timing, provided the Cooperative retires and pays capital credits to similarly situated patrons under the same manner, method, and timing. *[As determined by the Board, before the time the Cooperative anticipates normally retiring and paying capital credits, the Cooperative may retire some or all capital credits and pay the net present value of the retired capital credits. OR As agreed upon by the Cooperative and a patron or former patron, before the time the Cooperative anticipates normally retiring and paying capital credits allocated to the patron or former patron, the Cooperative may retire some or all of the capital credits and pay the net present value of the retired capital credits.]*

[9] Federal cooperative tax law does not require an exempt electric cooperative to notify patrons of annual capital credits allocations. A nonexempt electric cooperative may exclude or deduct from its taxable income capital credits allocated to a patron, but only if the cooperative provides the patron written notice of the stated dollar amount of the allocation within 8 1/2 months after the end of a fiscal year. Accordingly, if the Internal Revenue Service audits an exempt electric cooperative and determines that the cooperative was unintentionally nonexempt during an earlier year, then the cooperative must have provided this written notice in order to exclude or deduct allocated capital credits from its taxable income.

The Cooperative may regularly impose a reasonable dormancy or service charge for each *[month OR year]* a patron or former patron fails to claim capital credits retired and paid to the patron or former patron. *[Through a voluntary written assignment signed by a patron or former patron, which assignment is revocable and is not a condition of the Cooperative providing a good or service to the patron, the patron or former patron may assign or transfer to the Cooperative any past, present, or future capital credits retired and paid to the patron or former patron, but not claimed by the patron or former patron within __________ (__) years of retirement and payment, provided the Cooperative undertook or undertakes reasonable measures to notify the patron or former patron of the retired and paid capital credits.]*

Appendix 5: Sample Board Policy

This "Sample Electric Cooperative Capital Credit Policy" is based upon general state cooperative law and federal cooperative tax law. It is not based upon the law of any particular state. In addition, this policy incorporates recommendations by the Capital Credits Task Force, as well as capital credits philosophical considerations discussed during task force meetings. This policy is primarily for an electric distribution cooperative that is exempt from federal income taxation, with flexibility for years during which the cooperative intentionally or unintentionally becomes nonexempt, or taxable.

Because state laws vary, and because electric cooperatives may reach different capital credits philosophical decisions and have different tax considerations, each cooperative should individually review and revise this policy to comply with its unique needs, desires, and requirements. This is not a "model" policy to be adopted without extensive review, consideration, and discussion. ***Before considering, adopting, or revising a capital credits policy, an electric cooperative should consult with its attorney and tax consultant.***

SAMPLE BOARD POLICY

Capital Credits Policy of ____________________
Adopted __________

I. Objective.

The objective of this Capital Credits Policy ("Policy") is to state the general policy of ____________________ ("Cooperative") for allocating and retiring capital credits.

II. Policy.

The Cooperative shall allocate and retire capital credits in a manner that: (1) is consistent with state and federal law; (2) is consistent with operating on a cooperative basis under federal tax law; (3) is fair and reasonable to the Cooperative's patrons and former patrons; (4) provides the Cooperative with sufficient equity and capital to operate effectively and efficiently; and (5) protects the Cooperative's financial condition. Subject to law, the Cooperative's articles of incorporation, and the Cooperative's bylaws, the allocation and retirement of capital credits are at the sole discretion of the Cooperative's Board of Directors ("Board").

III. Expectations.

A. **Board Approval.** The Cooperative shall allocate and retire capital credits according to the manner, method, timing, and amount approved by the Board.

B. **Patronage Earning Allocations.** For each good or service provided by the Cooperative on a cooperative basis during a fiscal year, the Cooperative shall equitably allocate to each patron, in proportion to the value of the good or service purchased by the patron during the fiscal year, the Cooperative's patronage earnings from providing the good or service during the fiscal year.

C. **Patronage Loss Allocations.** For each good or service provided by the Cooperative on a cooperative basis, the Cooperative shall offset patronage losses with the Cooperative's patronage earnings from providing the good or service during the next succeeding future fiscal year(s).

D. **Nonpatronage Earning Allocations.** As approved by the Board, the Cooperative may use, retain, or equitably allocate the Cooperative's nonpatronage earnings.

E. **Nonpatronage Loss Allocations.** The Cooperative shall offset nonpatronage losses with the Cooperative's nonpatronage earnings during any fiscal year.

F. **General Capital Credits Retirements.** The Cooperative shall generally retire capital credits with the goals of: (1) maintaining an equity level between __________ percent (_____ %) and __________ percent (_____ %) of the Cooperative's total assets; (2) retiring some capital credits every year during the month(s) of __________; (3) retiring capital credits on a ______________________________ basis; (4) retiring capital credits within __________ (_____) years after their allocation; (5) communicating and promoting the cooperative principles; (6) fostering loyalty and support among patrons and former patrons; and (7) maximizing public relations and political goodwill.

G. **Special Capital Credits Retirements.** The Cooperative: (1) may specially retire capital credits upon the death of an individual patron or former patron; (2) may not specially retire capital credits upon the dissolution, liquidation, or cessation of existence of an entity patron or former patron; (3) may not specially retire capital credits upon the reorganization, merger, or consolidation of an entity patron or former patron; (4) may not specially retire capital credits upon a patron or former patron reaching a certain age; (5) may not specially retire capital credits upon a patron becoming a former patron; (6) may not specially retire capital credits upon a patron failing to pay an amount owed to the Cooperative within __________ (_____) days of the date payment was due; and (7) may specially retire capital credits upon a former patron failing to pay an amount owed to the Cooperative within __________ (_____) days of the date payment was due.

H. **Discounted General Capital Credits Retirements.** The Cooperative may not generally retire capital credits before the time the Cooperative anticipates normally retiring the capital credits and pay the discounted, net present value of the capital credits.

I. **Discounted Special Capital Credits Retirements.** For capital credits specially retired before the time the Cooperative anticipated normally retiring the capital credits, as agreed upon by the Cooperative and a patron or former patron, the Cooperative may pay the discounted, net present value of the capital credits.

J. **Recoupment.** After retiring, and before paying, capital credits allocated to a patron or former patron, the Cooperative may recoup, offset, or setoff any amount owed to the Cooperative by the patron or former patron by reducing the amount of retired capital credits paid to the patron or former patron by the amount owed.

IV. Limitations.

A. **Forfeiture of Capital Credits.** The Cooperative shall not enter contracts through which a patron or former patron forfeits the right to the allocation or retirement of capital credits. The Cooperative shall not require any patron or former patron to forfeit the right to the allocation or retirement of capital credits.

B. **Patron Classes.** As reasonable and fair, and as approved by the Board, the Cooperative may allocate or retire capital credits to classes of similarly situated patrons or former patrons under different manners, methods, timing, and amounts, provided the Cooperative allocates and retires capital credits to similarly situated patrons and former patrons under the same manner, method, timing, and amount.

C. **Separate Allocations and Retirements.** The Cooperative shall separately identify and allocate to the Cooperative's patrons capital credits and similar amounts allocated to the Cooperative by an entity in which the Cooperative is a member, patron, or owner. The Cooperative may retire these separately identified and allocated capital credits only after the entity retires and pays the amounts to the Cooperative.

D. **Notice of Allocation.** Within eight and one-half (8 1/2) months following a fiscal year, the Cooperative shall notify each patron in writing of the amount of capital credits allocated to the patron for the preceding fiscal year through a written notice stating the dollar amount allocated.

E. **Adverse Financial Impact.** The Cooperative shall not retire any capital credits unless the Board first determines that the retirement will not adversely impact the Cooperative's financial condition.

F. **Request and Agreement for Special Retirement.** The Cooperative may specially retire capital credits upon the death of a patron or former patron only upon receiving a written request from the appropriate legal representative, and only under terms and conditions agreed upon by the Cooperative and the appropriate legal representative.

G. **Discount Rate.** If the Cooperative retires capital credits before the time the Cooperative anticipates normally retiring the capital credits and pays the discounted, net present value of the capital credits, then the Cooperative shall use a discount rate equaling the Cooperative's weighted cost of capital.

H. **Minimum Amount.** The Cooperative shall not retire and pay capital credits in an amount less than five dollars ($ 5.00), unless the retirement and payment is for all remaining capital credits allocated to a former patron.

I. **Payment and Notice of Retirement.** After the Cooperative retires capital credits allocated to a patron, the Cooperative shall pay the retired amount by sending a check for the amount to the patron's most current address listed on the Cooperative's records. After the Cooperative retires capital credits allocated to a former patron, the Cooperative shall pay the retired amount by sending a check for the amount to the former patron's most current address listed on the Cooperative's records.

J. **Unclaimed Capital Credits.** If a patron or former patron fails to claim a retired capital credits amount within __________ (_____) days, then the Cooperative shall send a notice regarding the failure to the patron or former patron's most current address listed on the Cooperative's records. If the patron or former patron fails to claim the retired amount within __________ (_____) days after the notice, then, for each year the patron or former patron fails to claim the retired amount, the Cooperative may impose a dormancy or service charge equaling __________ dollars ($ _____). If a patron or former patron fails to claim the retired amount within __________ (_____) years, then the Cooperative shall provide any notice and take any other action required by law, and may use the amount as permitted by law.

V. Responsibility.

A. **Implementation of Policy.** The Cooperative's general manager or chief executive officer ("Manager") is responsible for implementing this Policy and for developing the practices and procedures necessary to allocate and retire capital credits according to this Policy.

B. **Recommendations to Board.** The Cooperative's Manager is responsible for: (1) recommending to the Board the manner, method, timing, and amount for allocating and retiring capital credits; and (2) when in the best interest of the Cooperative and its patrons and former patrons, recommending to the Board revisions to this Policy.

C. **Review and Approval by Board.** The Board is responsible for: (1) reviewing, discussing, and evaluating the Manager's recommendations regarding the manner, method, timing, and amount for allocating and retiring capital credits; (2) approving the manner, method, timing, and amount for allocating and retiring capital credits; (3) reviewing, discussing, and evaluating this Policy every year; (4) reviewing, discussing, and evaluating the Manager's recommendations for revising this Policy; and (5) revising this Policy.

D. **Compliance with Policy.** The Board is responsible for the Cooperative's compliance with this Policy.

Appendix 6: Equity Management Theory

Revisiting Equity Management—The Art of Wise Compromise

Claudia Phillips, Vice President of Programs and Planning Analysis, CFC

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Background

The rural electric program had its beginnings in Franklin Roosevelt's first term as president in the 1930s. It was simultaneously an effort to bring electricity to the rural areas and create jobs in the 48 states then building the electric lines, wiring houses and operating the newly created electric systems.

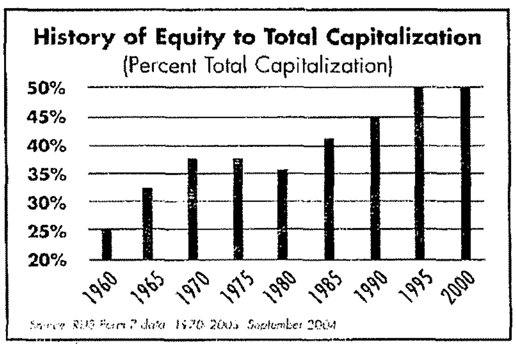
In most of the areas where the rural electrification program was established to provide electric service, the existing investor-owned utility companies exhibited little interest in making the necessary investments to serve the rural areas on an area-coverage basis. In their opinion, there would never be sufficient demand for electric service to provide the rate of return they deemed necessary to justify the investment.

In order for many projects to show feasibility, most Rural Electric Administration (REA) borrowers were established as non-profit cooperative corporations. In most states, enabling legislation had to be enacted to provide a framework under which these non-profit cooperative corporations could be created. As of December 31, 2000, most CFC and RUS (formerly REA) distribution borrowers are electric cooperatives with a relatively small group of public power districts (Nebraska) or public utility districts (Washington and Oregon).

These projects were feasible only with the combined advantages of long-term, low-interest REA loans for 100 percent of the project cost, exemption from federal income taxes because of their non-profit cooperative status, standardization of accounting, reporting, construction, etc. and a wealth of technical assistance from REA.

Most, if not all REA borrowers, were incorporated with an equity, which consisted only of a $5 per consumer "membership fee" that was consumed largely by the organizational expenses of the fledgling businesses.

The Need for Margins and Equity



From the beginning, RUS recommended that its borrowers earn margins to build reserves against contingencies and to provide the rural electric cooperative members with some equity in the system that they "owned" but which was mortgaged to the federal government. It was evident in both policy and mortgage documents that a 40 percent equity level was desirable.

A capital credits allocation and refunding plan evolved that provided the rationale for a non-profit corporation charging rates for service in excess of the cost of providing service and "allocating" the "margins" back to the member-owners in proportion to their patronage. Provision was made to refund or revolve these allocated credits back to the members when cooperative boards of directors deemed that the financial condition of the cooperative justified the capital credits refund.

Since that time, the composite equity of the rural electric distribution program has grown to 47 percent of total capitalization.

The Importance of Adequate Earnings Ratios

During the 1970s, when the federal government was faced with the situation that the growing capital requirements of the program far exceeded amounts they were willing to authorize, CFC was created by program leaders as a vehicle to attract capital in the private capital market. Today, with loans and guarantees outstanding to members of approximately $22 billion, CFC continues to meet these needs.

As a private lender, CFC plays a significant role in educating the financial community about the financial health of its rural electric cooperative members. In fact, in connection with its first Collateral Trust Bond issue, CFC made potential investors aware of the rural electric program's outstanding composite earnings track record. During the decade preceding the sale of these collateral trust bonds, the composite earnings ratio of all rural electric distribution systems was within the 3.23 to 3.73 range, with the trend being upward with time. These consistently strong ratio achievements have contributed to CFC's ability to earn solid bond ratings from S&P and Moody's from its early years to today.

Since CFC's credit is a reflection of the creditworthiness of its member systems, its ability to sell long-term bonds at favorable interest rates is in large part a function of each member-distribution system maintaining adequate earnings ratios and equity levels.

Next Stage in the Life Cycle

The jump from meeting federal government requirements to meeting Wall Street's requirements to attract additional sources of debt capital on the open market required consistent maintenance of acceptable terms such as coverage and equity.

> **As part of this effort, CFC and NRECA created the Capital Credits Study Committee in 1976. The committee's charter was to study all aspects of the ideas, work and methods from various individuals and groups in the rural electric program, and develop and promulgate concepts regarding margins, equity levels and, ultimately, revenue requirements.**

Regulatory commissions accepted the premise that investor-owned utilities must be allowed a rate of return sufficient to cover the interest on their outstanding long-term debt and to provide a reasonable return on the equity capital invested by the owners or stockholders. Soon cooperative leaders rapidly embraced the same philosophy.

Equity Management Planning

Mathematical models were developed, and later improved, that contained principal concepts indicating that there was an "optimum" equity level for every cooperative. This optimum level being a function of each system's blended cost of debt capital, its capital credits revolving cycle, its rate of growth in total capitalization, and its TIER (Times Interest Earned Ratio) objective. The models were able to prove that if a system's actual equity level were either higher or lower than the optimum level, higher electric rates would be needed in order to provide sufficient revenues to satisfy all of the constraints operating to restrict the cooperative's freedom of action.

James Goodwin, formerly with the REA, is credited with some of the first work in equity management for rural electric cooperatives. Goodwin developed a formula, that was later modified, that produced a percentage return on equity (Re) that is still used today in equity management planning.

The modified Goodwin formula is as follows:

$$Re = \frac{(1 + g)^{n+1} - (1 + g)^{n}}{(1 + g)^{n} - 1} \times \text{“100”}$$

Where Re = Rate of Return on Equity (as a percentage)
g = Rate of Growth in Total Capitalization
n = Period of Capital Credit Rotation (in years)

The formula produces the rate of return on equity to be earned each year on the total equity as of December 31 of the prior year in order to hold equity at its present level.

A table for values of Re for varying growth rates and varying periods of patronage capital rotation follows:

Return On Equity %

Annual Rate of Growth	Period of Revolving Capital Credits (Years) 10	15	16	17	18	19	20	1000 (Infinity)
0.00	10.00	6.67	6.25	5.88	5.56	5.26	5.00	0.00
1.00	10.56	7.21	6.79	6.43	6.10	5.81	5.54	1.00
2.00	11.13	7.78	7.37	7.00	6.67	6.38	6.12	2.00
3.00	11.71	8.38	7.96	7.60	7.27	6.98	6.72	3.00
4.00	12.33	8.99	8.58	8.22	7.90	7.61	7.36	4.00
5.00	12.95	9.63	9.23	8.87	8.55	8.27	8.02	5.00
6.00	13.59	10.29	9.90	9.54	9.24	8.96	8.72	6.00
7.00	14.24	10.98	10.59	10.24	9.94	9.68	9.44	7.00
8.00	14.90	11.68	11.30	10.96	10.67	10.41	10.19	8.00
9.00	15.58	12.41	12.03	11.70	11.42	11.17	10.95	9.00
10.00	16.27	13.15	12.78	12.47	12.19	11.95	11.75	10.00
11.00	16.98	13.91	13.55	13.25	12.98	12.76	12.56	11.00
12.00	17.70	14.68	14.34	14.05	13.79	13.58	13.39	12.00
13.00	18.43	15.47	15.14	14.86	14.62	14.41	14.24	13.00
14.00	19.17	16.28	15.96	15.69	15.46	15.27	15.10	14.00
15.00	19.93	17.10	16.79	16.54	16.32	16.13	15.98	15.00
16.00	20.69	17.94	17.64	17.40	17.19	17.01	16.87	16.00
17.00	21.47	18.78	18.50	18.27	18.07	17.91	17.77	17.00
18.00	22.25	19.64	19.37	19.15	18.96	18.81	18.68	18.00
19.00	23.05	20.51	20.25	20.04	19.87	19.72	19.60	19.00
20.00	23.85	21.39	21.14	20.94	20.78	20.65	20.54	20.00

Using the Return on Equity chart to demonstrate, a system growing at 6 percent per year in total capitalization and revolving capital credits on a 20-year cycle would require an Re of 8.72 percent to maintain its present equity position. If a lower Re were earned, the percentage equity would fall. If a higher Re were earned, the percentage equity would increase. If a longer revolving cycle were used, a lower Re would be adequate. If a shorter cycle were used, a higher Re would be necessary. If there were no capital credits refunds (with a cycle of infinity years represented in the chart as "1000"), the Re would be the system's rate of growth in that year.

The second component of total capitalization is debt capital, or long-term debt. Technically, the blended cost of a system's long-term debt would be calculated by multiplying the outstanding balance on each long-term note by the interest rate on that note, summing the interest amounts together, summing the note balances together, and dividing the total interest by the total of the outstanding note balances. For convenience, an approximation of the blended interest could be determined by dividing the total interest paid (on long-term debt) by the average of the total debt outstanding for the last full year and prior year.

Interest	$470,000	
Principal	(7,500,000 + $8,166,666)/2	= 6.0% Cost of Debt

It is important to be aware that the rate of change in the cost of debt can be influenced by many factors including:

- How fast new higher cost debt is requisitioned
- A system's rate of growth in plant
- The amount of internally generated funds invested in plant
- The amount refunded in capital credits each year
- How fast the older, low interest loans are amortized

The primary purpose of running a financially sound business in a financially sound manner is to ensure the availability of credit that will provide capital funds whenever debt capital is needed. While many factors enter into the ratings of credit risk and debt quality, the most commonly noted factor is interest coverage or TIER. By combining the criteria for patronage capital (as related to return on equity) with reasonable coverage criteria on interest charges (at what may be deemed a desirable capital structure) a valid indicator of the cooperative's financial health can be produced at minimal costs.

Putting the Pieces Together

Now, lets look at the total rates of return for a system having a 6 percent rate of growth (in TC), rotating capital credits on a 20-year cycle, and having a blended interest cost of 6 percent at various equity positions:

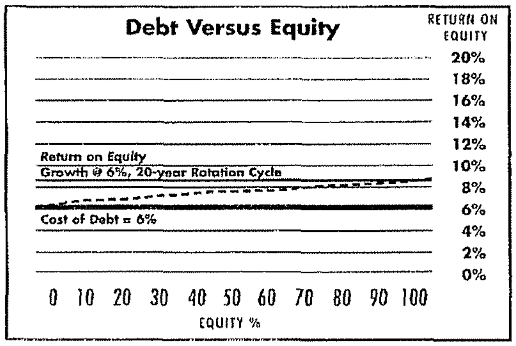
Equity Position	20%	40%	60%	80%
Equity @ 8.72%	1.74	3.49	5.23	6.98
Debt @ 6.00%	4.80	3.60	2.40	1.20
Total Rate of Return	6.54%	7.09%	7.63%	8.18%
TIER = (Rc + Interest) / Interest	1.36	1.97	3.18	6.82

When the constant equity return prevailed, there was insufficient interest coverage at the lower equity position and excess coverage at the higher equity position.

Next, let's look at the same system, with the same rates, with our constant criteria now being interest coverage, or TIER, of 3.0:

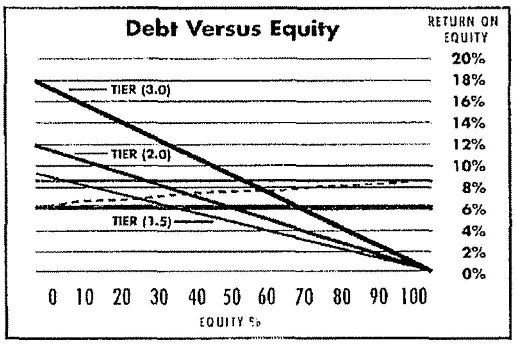
Equity Position	20%	40%	60%	80%
Equity Re Required	9.60	7.20	4.80	2.40
Interest	4.80	3.60	2.40	1.20
Total Rate of Return	14.40%	10.80%	7.20%	3.60%
$\text{TIER} = \frac{\text{Re} + \text{Interest}}{\text{Interest}}$	3.0	3.0	3.0	3.0

With a constant TIER goal, there is excessive return on equity at the lower equity positions and insufficient return on equity at the higher equity positions. It is obviously not prudent to operate at either extreme.



The graph at left provides a visual analysis of alternative approaches. Operating at 100 percent debt at 6 percent interest would be the cheapest alternative for the cooperative. Operating at 100 percent equity with a 20-year capital credits revolving cycle that results in an 8.72 percent return requirement would be the most expensive alternative. The diagonal line connecting the two denotes the blended cost alternatives of the debt and equity components to the cooperative.

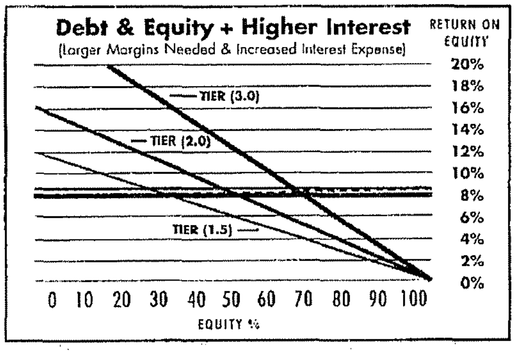
As a practical matter, however, virtually every cooperative operates using a mixture of debt and equity. Mortgage provisions of RUS and CFC set TIER at minimum levels of 1.25 to 1.50 to ensure debt and interest payment coverage. These targets are not expected to provide the necessary margins to operate the business, maintain equity and retire capital credits on a consistent cycle. Most cooperatives will find they need to operate at a TIER level of between 2.0 and 3.0 to generate sufficient margins and cash flows to carry out the goals and objectives established by their cooperative's board of directors.

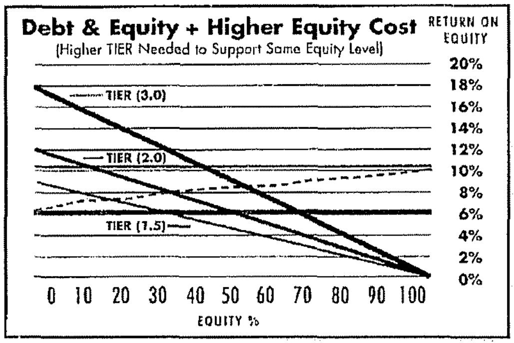


The example at left illustrates that, given the costs of debt and equity, a 2.0 TIER would support an equity level of 41 percent and a 3.0 TIER would support an equity level of 57 percent.

If interest costs were to rise to 8 percent, with everything else remaining the same, the resulting TIER level would drop. Larger margins would be needed, as the increased interest expense would drive up margin levels even though there is a lower TIER requirement.

If the cooperative chooses to maintain a 2.0 TIER, the resulting equity level would grow to 48 percent. A 3.0 TIER target would support an equity level of 64 percent.





If we assume that debt costs remain at 6 percent but equity costs increased as a result of growth to 8 percent and the capital credits revolving cycle remained on a 20-year cycle, our cost of equity rises to 10.19 percent. In the prior example the cooperative was able to maintain equity at 48 percent with a TIER of 2.0. Under this scenario, if the cooperative operates at a 2.0 TIER, the resulting equity level can be supported only to 38 percent. At a 3.0 TIER, equity would fall to 54 percent from the previous 57 percent. It is easy to see how the increases in debt and equity costs cause changes in TIER requirements.

The Art of Wise Compromise

Equity management concepts and models continue to remain a critical tool in developing and implementing equity management policies that are consistent with sound business practice and planning. Modeling enables a cooperative to test and set objectives at a level to support the optimum mix of debt and equity in order to minimize the cooperative's rate of return requirements and to meet its debt coverage obligations. In addition, it enables the cooperative to adhere to the cooperative principle of retiring capital credits back to its members as tangible evidence of ownership.

An electric cooperative, like any other business, functions in a dynamic environment. Change is constant and the cooperative doesn't always have control over that change. The needs of a cooperative's membership, along with the strategic goals of the cooperative, must be continually re-evaluated and balanced. Each cooperative's board and staff have an obligation to move the cooperative in the direction that best positions the organization for the future. While the future can't be precisely predicted for each electric cooperative, we do know that the stronger the organization is financially, the more likely they are to meet the promise of service to their membership.

CFC has recently reintroduced an equity management modeling package. The package includes four of the most common capital credits retirement alternatives. The software is currently available on CFC's Web site at www.nrucfc.coop (through the Extranet). CFC regional vice presidents and staff also are available to conduct in-depth equity management presentations to cooperative boards and staff.

The following checklist includes questions designed to help a board be sure it considers the important issues that

Appendix 7: Glossary

allocate capital credits
To assign capital credits to members/patrons.

capital credits
Margins credited to patrons of a cooperative based on their relative purchases from the cooperative. Capital credits are used by the cooperative as its primary equity base, then paid back to the membership as financial conditions permit. Capital credits reflect each member's ownership in the cooperative. Also called patronage capital or equity capital.

cooperative
A business that returns its margins to the members through capital credits allocations and retirements.

discount
To calculate the present value of an amount that would otherwise be received in the future to reflect the time value of money.

equity management
The phrase the cooperative network has historically used to refer to capital structure planning and decision making.

member
Any individual or entity that is entitled to participate in cooperative elections and vote and share in patronage capital allocations.

mutual company
A business that uses any margins above the cost of providing services to reduce costs in future years. Examples of mutual companies include mutual insurance associations, such as State Farm Insurance, and credit unions, such as the Agriculture Federal Credit Union. There are also a number of mutual electric associations.

non-operating margins
Income (revenues less related expenses) derived from non-electric products, services and/or investments.

non-patronage-sourced margins
Revenues resulting from activities that are not substantially related to the accomplishment of the co-op's marketing, purchasing or service activities less the expenses incurred to generate those revenues.

operating margins
Revenues derived from the co-op's marketing, purchasing or providing electric and other qualifying tax-exempt services, as well as other revenues derived from utilization of the co-op's electric plant assets, less the expenses incurred to supply those services.

patron
Any individual or entity doing business with the cooperative that is entitled to share in patronage capital allocations. All members are patrons. All patrons, however, are not necessarily members. Only members are entitled to participate in cooperative elections. A cooperative also may have customers that are neither patrons entitled to share in patronage capital allocations nor members entitled to vote.

patronage-sourced margins
Revenues resulting from transactions that directly facilitate accomplishing the co-op's marketing, purchasing or service activities, less the expenses incurred to generate those revenues.

reserves
Funds set aside to meet expected or unexpected future needs, such as plant expansion or storm recovery.

retire capital credits
To pay capital credits to members/patrons, either through cash, credit or property. Also called revolving, rotating or redeeming capital credits.

rotation period
The period of time that capital credits are held by the cooperative before being returned to members. For example, a co-op retiring capital credits using the first-in, first-out (FIFO) method and a 20-year rotation period would return capital credits allocated in 1984 in 2004.

vest
To confer ownership of property upon a person, to invest a person with full title to property or to give a person an immediate, fixed right of present or future enjoyment.

The information in this Report of the Capital Credits Task Force is intended to be a helpful resource, not an exhaustive and complete examination of capital credits issues. Although this information may be helpful, decisions regarding capital credits policies and procedures are within the discretion and judgment of local electric cooperatives. Because these policies and procedures will vary depending upon state law and specific facts and circumstances, and because the law governing capital credits may change, it is imperative for a cooperative to consult with its legal counsel, as well as its tax and accounting consultant, when reviewing and analyzing the information in this report.

National Rural Electric
Cooperative Association
A Touchstone Energy® Cooperative

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National Rural Utilities
Cooperative Finance Corporation
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2201 Cooperative Way
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703.709.6700 | www.nrucfc.coop

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-14)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 24) ***Please provide a table of patronage capital allocations by Big Rivers to Kenergy by retail endpoint for each year from 2007 through 2010 in substantially the same format as shown on the attached table which shows Big Rivers' patronage capital allocations to Kenergy by retail endpoint for the year 2006.***

Response) Please see the attached table which details Big Rivers' patronage capital allocations to Kenergy Corp. by wholesale delivery point for each of the years 2007 through 2009.

As stated in Big Rivers' response to KIUC Item 1-55, the 2010 patronage allocation, if any, has not yet been determined. Per Big Rivers' Bylaws, Big Rivers allocates patronage on a federal income tax basis, annually (not monthly), by September 15 of the following calendar year. Note that as a result of terminating the sale-leaseback of its Green and Wilson generating facilities in 2008, and the Unwind Transaction in 2009, Big Rivers does not currently anticipate either regular taxable patronage-sourced income or alternative minimum taxable patronage-sourced income.

Witness) Mark A. Hite

Big Rivers Electric Corporation
Case No. 2011-00036
PATRONAGE CAPITAL ALLOCATION TO KENERGY BY DELIVERY POINT

	DELIVERY POINT	2007 Allocation	2008 Allocation	2009 Allocation
	(1)	(2)	(3)	(4)
1	ACCURIDE CORPORATION	251,294.55	228,947.79	4,616,418.47
2	ALCOA, INC. - AA	86,932.34	13,277.86	2,984,080.82
3	ALCOA HAWESVILLE WOR	0.00	0.00	186,651.84
4	ALERIS INTERNATIONAL	1,012,407.25	924,744.42	22,751,591.27
5	ALLIED RESOURCES, IN	228,554.97	229,160.73	1,000,134.81
6	ARMSTRONG - BIG RUN	39,247.74	75,467.53	547,253.78
7	ARMSTRONG - DOCK	0.00	0.00	59,746.93
8	ARMSTRONG - MIDWAY	437.09	83,357.52	239,982.00
9	BRECKINRIDGE - PEABO	0.00	0.00	6,278,355.07
10	CARDINAL RIVER RESOU	31,249.14	3,919.76	191,556.88
11	CR MINING, INC.	0.00	0.00	16,209.92
12	DOMTAR PAPER CO LLC	840,696.97	778,470.04	40,210,078.49
13	DOTIKI #3 - WEBSTER	20,797.76	21,941.67	448,937.30
14	DYSON CREEK MINE - P	23,265.41	4,292.87	4,381,737.12
15	HOPKINS COUNTY COAL,	13,103.25	13,381.76	1,402,067.37
16	K B ALLOYS, INC.	100,566.77	89,117.91	1,794,092.10
17	KIMBERLY CLARK	1,050,055.42	997,474.80	20,484,346.62
18	KMMC, L.L.C.	153,245.79	23,262.67	989,073.51
19	PATRIOT COAL LP	212,573.01	212,467.46	2,875,495.46
20	ROLL COATER	158,935.08	150,300.59	2,961,182.85
21	TYSON FOODS, INC.	363,007.76	339,789.33	5,324,542.16
22	VALLEY GRAIN	96,713.52	92,477.04	1,727,504.19
23	WEBSTER COUNTY COAL	0.00	0.00	26,214.20
24	Adams Lane	191,003.10	155,994.90	859,474.91
25	Beda	254,937.34	240,885.78	4,291,004.70
26	Beech Grove	129,996.33	128,760.02	2,542,119.14
27	Bon Harbor	196,154.44	184,971.25	2,014,284.12
28	Caldwell Springs	71,737.86	69,434.72	509,539.35
29	Centertown	73,051.61	70,813.60	1,291,647.92
30	Crossroads	186,764.36	180,807.87	1,245,960.15
31	Dermont	205,836.11	188,442.35	3,970,611.42
32	Dixon	157,309.10	144,568.77	2,555,840.74
33	East Owensboro	143,917.08	157,743.28	889,992.86
34	Geneva	211,103.41	210,916.90	3,330,949.74
35	Guffie	203,999.13	205,689.35	3,232,301.13
36	Hanson	91,441.21	88,028.31	615,449.47
37	Hawesville	245,099.73	221,930.71	4,734,572.00
38	Horse Fork	309,745.65	276,426.81	3,301,792.85
39	Hudson Substation	182,748.57	147,392.52	2,666,836.27
40	Lewisport	276,302.96	252,829.33	5,211,286.18
41	Little Dixie	112,058.92	107,406.41	2,100,423.55
42	Lyon County	158,114.70	150,417.17	3,308,591.45
43	Maceo	115,414.76	108,377.07	802,563.53
44	Madisonville	103,379.99	129,567.84	386,066.58
45	Marion	210,801.54	204,897.18	4,736,911.03
46	Masonville	114,755.03	103,611.86	2,512,611.36
47	Morganfield	301,517.57	271,144.91	5,406,300.16
48	Niagara	238,049.53	221,889.51	4,241,208.95
49	Nuckols	183,415.11	157,859.97	3,096,534.32
50	Onton	162,149.01	158,870.94	2,603,708.90
51	Philpot	312,165.86	269,199.65	5,242,277.49
52	Pleasant Ridge	165,628.49	155,861.57	1,085,726.90
53	Providence	174,540.16	140,914.10	4,021,595.88
54	Race Creek	223,605.04	201,868.28	4,947,478.52

Big Rivers Electric Corporation
Case No. 2011-00036
PATRONAGE CAPITAL ALLOCATION TO KENERGY BY DELIVERY POINT

	DELIVERY POINT	2007 Allocation	2008 Allocation	2009 Allocation
	(1)	(2)	(3)	(4)
1	Riverport	44,682.83	54,559.27	705,820.61
2	Sacramento	109,625.32	100,321.54	1,796,772.31
3	Sebree	154,468.25	143,086.37	2,558,117.81
4	South Dermont	442,102.34	382,357.24	7,313,387.39
5	South Hanson	415,144.53	386,609.53	7,678,056.10
6	South Owensboro	340,926.24	298,584.17	7,639,330.15
7	St. Joe	134,346.72	122,809.61	2,176,625.97
8	Stanley	107,995.48	109,630.83	1,994,609.91
9	Sullivan	120,101.57	108,028.21	2,117,543.27
10	Thruston	264,580.60	247,332.30	6,495,900.75
11	Utica	203,977.59	193,348.66	4,549,811.44
12	Weaverton	167,807.61	158,541.43	4,205,718.77
13	Weberstown	199,659.59	201,718.85	2,882,074.75
14	West Owensboro	216,112.53	205,522.35	4,471,080.65
15	Whitesville	246,548.75	230,357.67	4,996,664.00
16	Wolf Hills	86,115.00	96,734.98	613,776.85
17	Yeager	1,817.20	1,028.84	52,880.00
18	Zion	241,884.98	228,232.16	5,836,632.23
19	CENTURY	12,501,222.63	7,170,570.44	40,222,757.51
20	ALCAN	10,221,789.72	5,927,738.87	32,855,601.41
21	RELIANT/ALCAN	0.00	0.00	1,224,391.39
22	Total	36,610,737.00	25,956,488.00	351,640,468.00

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT___(LK-15)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 25) ***Please provide a table of patronage capital allocations by Big Rivers to Kenergy, subdivided by rural customers, large industrial customers, smelter customers, and total, for each year from 2007 through 2010 in substantially the same format as shown on the attached table which shows Big Rivers' patronage capital allocations to Kenergy by customer group for the years 2000 through 2006.***

Response) Please see the attached table of patronage capital allocations by Big Rivers to Kenergy, subdivided by Kenergy's rural delivery points, large industrial delivery points, and smelter delivery points, for each years 2007 through 2009.

As stated in response to KIUC 1-55, Big Rivers' patronage allocation for tax year 2010, if any, has not yet been determined. Per Big Rivers' bylaws, Big Rivers allocates patronage on a federal income tax basis, annually (not monthly), by September 15 of the following calendar year. Note that as a result of terminating the sale-leaseback of its Green and Wilson generating facilities in 2008, and the Unwind Transaction in 2009, Big Rivers does not currently anticipate either regular taxable patronage-sourced income or alternative minimum taxable patronage-sourced income.

Witness) Mark A. Hite

Big Rivers Electric Corporation
Case No. 2011-00036
Patronage Allocation to Kenergy By Customer Class
Years 2007-2009

		Large Industrials	Rurals	Smelters	Total
	(1)	(2)	(3)	(4)	(5)
1	**2007**	4,683,084	9,204,641	22,723,012	36,610,737
2	**2008**	4,281,852	8,576,327	13,098,309	25,956,488
3	**2009**	121,497,253	155,840,465	74,302,750	351,640,468
4		130,462,189	173,621,432	110,124,072	414,207,693

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	CASE NO. 2011-00036
A GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT___(LK-16)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 26) ***Please provide a table of patronage capital allocations by Big Rivers to each of its three Members, subdivided by rural customers, large industrial customers, smelter customers, and total, and cumulative patronage, for each year from 2007 through 2010 in substantially the same format as shown on the attached table which shows Big Rivers' patronage capital allocations to Kenergy by customer group for the years 2000 to 2006.***

Response) Please see the attached table of patronage capital allocations by Big Rivers to each of its three Members, subdivided by their rural delivery points, large industrial delivery points, and smelter delivery points, for each of the years 2000 through 2009.

As stated in response to KIUC 1-55, Big Rivers' patronage allocation for tax year 2010, if any, has not yet been determined. Per Big Rivers' bylaws, Big Rivers allocates patronage on a federal income tax basis, annually (not monthly), by September 15 of the following calendar year. Note that as a result of terminating the sale-leaseback of its Green and Wilson generating facilities in 2008, and the Unwind Transaction in 2009, Big Rivers does not currently anticipate either regular taxable patronage-sourced income or alternative minimum taxable patronage-sourced income.

Witness) Mark A. Hite

Big Rivers Electric Corporation
Case No. 2011-00036
Patronage Allocations

		Meade	Jackson Purchase			Kenergy				Total				
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2	Year	Rurals	Rurals	Large Industrials	Total	Rurals	Large Industrials	Smelter Tier 3	Total	Rurals	Large Industrials	Smelter Tier 3	Total	Cumulative
3	2000	36,838,960	55,177,236	4,450,476	59,627,712	98,593,481	90,513,180	0	189,106,661	190,609,677	94,963,656	0	285,573,333	285,573,333
4	2001	2,409,556	3,485,064	268,750	3,753,814	6,309,949	5,254,207	994,740	12,558,896	12,204,569	5,522,957	994,740	18,722,266	304,295,599
5	2002	2,554,655	3,749,823	232,712	3,982,535	6,706,894	4,620,885	1,072,428	12,400,207	13,011,372	4,853,597	1,072,428	18,937,397	323,232,996
6	2003	2,475,228	3,477,440	182,090	3,659,530	6,276,244	3,944,363	2,684,852	12,905,459	12,228,912	4,126,453	2,684,852	19,040,217	342,273,213
7	2004	2,153,064	3,018,046	166,394	3,184,440	5,430,293	3,209,733	4,085,089	12,725,115	10,601,403	3,376,127	4,085,089	18,062,619	360,335,832
8	2005	2,818,035	3,932,438	214,859	4,147,297	7,106,315	3,903,685	5,142,264	16,152,264	13,856,788	4,118,544	5,142,264	23,117,596	383,453,428
9	2006	3,304,956	4,709,738	182,235	4,891,973	8,384,099	4,548,362	10,802,551	23,735,012	16,398,793	4,730,597	10,802,551	31,931,941	415,385,369
10	2007	3,720,028	5,174,676	195,143	5,369,819	9,204,641	4,683,084	22,723,012	36,610,737	18,099,345	4,878,227	22,723,012	45,700,584	461,085,953
11	2008	3,510,622	4,911,285	174,970	5,086,255	8,576,327	4,281,852	13,098,309	25,956,488	16,998,234	4,456,822	13,098,309	34,553,365	495,639,318
12	2009	60,069,607	87,243,708	5,804,986	93,048,694	155,840,465	121,497,253	74,302,750	351,640,468	303,153,780	127,302,239	74,302,750	504,758,769	1,000,398,087
13		119,854,711	174,879,454	11,872,615	186,752,069	312,428,707	246,456,604	134,905,996	693,791,307	607,162,872	258,329,219	134,905,996	1,000,398,087	

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-17)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES	)	PSC CASE NO.
OF EAST KENTUCKY POWER	)	2010-00167
COOPERATIVE, INC.	)	

TESTIMONY OF
DANIEL M. WALKER
ON BEHALF OF
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: May 27, 2010

Q. Please state your name and business address.

A. My name is Daniel M. Walker. I am an advisor on cooperative finance. My business address is 7106 University Drive, Richmond, Virginia, 23229.

Q. Please describe your relevant experience and educational background.

A. I hold a Bachelor's degree from Appalachian State University and a Master of Business Administration degree from the University of Richmond. I have published articles on regulation in the College of William & Mary Business Review, EPRI Research Journal, and Public Utilities Fortnightly. I served as Director of Public Utility Accounting and Finance for the Virginia State Corporation Commission and as a public utility consultant, testifying in civil and administrative cases in Virginia, Florida, Kentucky, Ohio, Arizona, and Alaska. In addition, I served as the Chief Financial Officer for Old Dominion Electric Cooperative for 21 years. In that capacity, I was directly responsible for the issuance of approximately $3 billion of cooperative financings. Also, in that capacity I testified on behalf of Old Dominion and its members before the Virginia State Corporation Commission, the Maryland Public Service Commission, the Delaware Public Service Commission, and the Federal Energy Regulatory Commission. As an advisor to G&Ts, I have assisted in placing over $3 billion of financing in the capital markets.

Q. What is the purpose of your testimony?

A. I have been asked by East Kentucky Power Cooperative to prepare an independent appraisal of East Kentucky's cost of capital and to recommend Times Interest Earned Ratio (TIER) and equity levels for ratemaking that are fair to East Kentucky and its member/owners that will allow East Kentucky to attract capital on reasonable terms and to maintain its financial integrity.

Q. Please summarize your testimony and recommendations.

A. I developed a recommendation for East Kentucky based on TIER, DSC, and equity metrics from BBB+ to A+ rated G&Ts. Because of the changing credit environment and East Kentucky's current less than favorable credit position, it is critical that it has in place rates which will produce an earned TIER sufficient to attract capital.

Q. How did you estimate East Kentucky's cost of capital?

A. First, I evaluated East Kentucky's credit using the same techniques that the debt rating agencies use. Second, I selected a proxy group of rated cooperatives that are comparable to East Kentucky. The regulatory principle of a "fair rate of return" requires that the cost of capital be determined by comparing achieved earnings of companies with corresponding risk. Third, I averaged the proxy group's earned TIERs for the last three reporting years. Fourth, I narrowed the proxy group of cooperatives to those cooperatives that have been evaluated and given a debt rating of BBB+ to A+ from at least one of the three major rating agencies. I call these G&Ts the "Reference Group." In addition I also analyzed a collection of data prepared by National Rural Utilities Cooperative Finance Corporation (CFC). This data compared East Kentucky with 21 G&Ts that generate the majority of their power requirements from their own resources. This data also compared East Kentucky with over 60 G&Ts that are members of CFC.

Cost of Capital

Q. How do you define the required rate of return or cost of capital used to set rates for a cooperative?

A. In the regulatory arena the cost of capital is a measure of a "fair" rate of return.

> "At a minimum, a public utility must be afforded the opportunity not only of assuring its financial integrity so that it can maintain its credit standing and attract additional capital as needed, but also of achieving earnings (*margins*) comparable to those of other companies having corresponding risk."[1]

This is a fundamental principle of finance whether the utility is regulated or unregulated. For a cooperative using TIER (interest coverage) to set rates, the rate of return is the margin left over after covering all costs, expressed in a ratio of margin to interest cost. In determining a rate level, capital-attracting adequacy is properly considered a basic test of a fair return. A utility must be able to attract capital at a reasonable cost in order to build and maintain physical plants and to meet its public service obligations. Failure to maintain the financial integrity of a cooperative is against the interest of its members as well as the lenders of capital. The first step in determining cost of capital is to establish risk parameters.

Q. How do you determine the appropriate risk parameters?

A. The most important sources of an independent evaluation of risk and credit are the three major rating agencies: Standard & Poor's (S&P), Moody's Investors Service (Moody's), and Fitch. It is fundamental that expected returns or TIERs are directly related to the perceived risk of an investment. It follows that if a particular cooperative has a risk profile similar to other rated cooperatives, its cost of capital will also be similar to that of the rated cooperatives. In most cases, to determine the cost of capital for a cooperative, one would

[1] Charles Phillips, Jr., "The Regulation of Public Utilities," Public Utilities Reports, Inc., p. 331.

compare its financial performance with cooperatives of similar risk as determined by the three major rating agencies. In other words, to attract capital it is reasonable to assume lenders would expect cooperatives with similar risk to have similar financial performance.

Q. Does this model work for East Kentucky?

A. Yes. This model is especially important to East Kentucky because its credit position must improve in order to attract capital. To restore positive credit credentials, East Kentucky must earn a TIER on a **consistent basis** that would result in a credit assessment equivalent to the BBB+ to A+ range to attract capital.

Q. Is East Kentucky currently rated?

A. No. However, by applying the principles used by the rating agencies, a proxy rating can be determined.

Q. Could you briefly explain what factors are considered important by the rating agencies in assessing a cooperative's risk?

A While each of the rating agencies has a different rating methodology, they tend to concentrate their evaluation of cooperatives in several areas. A "credit negative" in one agency may also be a credit concern in the other agencies. General areas of evaluation are:

(1) Financial Performance

(2) Flexibility to Change Rates/Regulatory Environment

(3) Long-Term Wholesale Contract with Members

(4) Member Profile

(5) Size

The above list is ranked in the general order of importance given by the particular rating agency's committees in developing credit ratings.

1. Financial Performance

The bottom line indicator on how well a cooperative has managed its risk is the financial results of its operations. The agencies analyze a variety of indicators and ratios to measure the ability to cover fixed and variable obligations. The key ratios analyzed are interest or debt service coverages, liquidity, and equity. For the purposes of my study I have concentrated on TIER and equity ratio since the Kentucky Public Service Commission uses these indicators to set rates. The rating agencies also apply stress to financial results to test the ability of cooperatives to deal with uncertainties in their financial operations. The reason financial performance is given the most weight by lenders is that financial performance demonstrates the cooperative's ability to service its obligation, which could have a direct impact on the value of the lender's investment. For example, a downgrade in a credit rating of a cooperative could decrease the value of that cooperative's bonds held in a bondholder's portfolio. The bondholder is concerned about a cooperative's credit at both the time of issuance and on an ongoing basis.

2. Flexibility to Change Rates/Regulatory Environment

Most of the cost exposure to cooperatives, such as fuel, is unregulated in the U.S. The cooperative needs the flexibility to raise or lower rates in order to track dramatic changes in cost levels. This holds true also for environmental requirements and capital investments to provide service. Not all cooperatives are regulated. Cooperatives that serve in states that are regulated have more difficulty raising rates compared to peers who are subject only to their board of directors for authority to change rates. An unsupportive regulatory jurisdiction is a credit negative and leaves cooperatives with less flexibility to raise rates if needed. Of the 21 rated G&T cooperatives, only two are state regulated for rates, and three are regulated by the Federal Energy Regulatory Commission (FERC). The FERC regulated co-ops use a flexible automatic adjustment formula to adjust rates. In Moody's evaluation of risk, financial performance and rate flexibility account for 60% of the credit evaluation.

3. Long-term Wholesale Contracts

The contracts between cooperatives and their members provide a high degree of assurance that cost and capital investments can be recovered in rates. The trend in the industry is to extend existing contracts for 30 or more years. Cooperatives such as Oglethorpe have extended their member contract to 2050. Most lenders, either in the capital market or RUS, are generally not issuing new loans beyond the maturity date of existing wholesale power contracts. Shorter maturities result in fewer numbers of years to recover fixed cost, thus increasing the cost per year. This situation is considered a credit negative by the rating agencies. Generally, the longer the contract, the greater assurance the cost of assets will be recovered and the debt repaid.

4. Member Profile

The member profile is important because it is the members that are the primary source of cash flow. The credit strength of the members, whether they are "end-of-line" member consumers or purchase for resale distribution members of a G&T cooperative, is an important factor to the credit strength of the cooperative. If a cooperative has members with poor credit fundamentals, it is a credit negative for the system.

5. Size

This factor, while the least important, still matters. The larger the entity, the greater the ability to withstand unexpected events. Also, the greater the size, the greater the ability to take advantage of economic diversity such as fuel mix and new generation. On the other hand, smaller utilities or utilities that have sufficient load loss have difficulty adjusting to significant events.

Listed below are the cooperatives that have investment grade ratings as of December 31, 2009:

<u>Cooperatives with Investment-Grade Ratings</u>

G&T Cooperatives	**Moody's**	**S&P**	**Fitch**
Arkansas Electric Cooperative	A2	AA- (Neg.)	A-
Associated Electric	A1	AA	AA
Basin Electric Power	A1	A+	AA-
Brazos	---	A-	A
Buckeye Power	A1	A+	A+
Central Electric – South Carolina	---	AA	---
Central Iowa		A	A-
Chugach Electric Association	A3	A-	A-
Dairyland Power Cooperative	A3	A	
Georgia Transmission Cooperative	A3	AA-	AA-
Golden Spread	A3	A	A-
Great River Energy	A3	A-	A-
Hoosier Energy Rural	Baa2	BBB-	---
Oglethorpe Power	A3 (Neg.)	A	A
Old Dominion Electric	A3	A	A
Power South	Baa1	A-	A-
Seminole Electric Cooperative	---	A-	---
Square Butte Electric Cooperative	A1	A-	---
Tri-State G&T Association	Baa1	A	A- (Neg.)
Wabash Valley	---	A-	---
Western Farmers	---	BBB+	A-

Q. Would you explain how credit positives and credit negatives work in particular applications?

A. Each utility has its own "basket of risks" to manage and still provide service on a daily basis. Most experts would agree that each utility has a collection of factors that are either credit positives or credit negatives. Since the credit crisis following the collapse of Enron, the ability to maintain credit standing has become demanding and difficult. In 2002, subsequent to the Enron collapse, there were substantially more downgrades than upgrades by S&P. The challenges for a utility are to mitigate credit negatives and improve credit positives when possible. Unfortunately, each utility experiences events beyond its control which may create a credit negative. Weather and unexpected economic conditions that impact demand are good examples of such events.

Within a rating category, each cooperative has different credit negatives and positives. For example, consider two cooperatives, Cooperative (A) and Cooperative (B), with the exact same letter credit rating. Cooperative (A) may build into rates a higher TIER that could be a credit positive; however, it may also have a credit negative that limits rate flexibility, such as that which occurs with rate regulation. Cooperative (B), on the other hand, may build into rates a lower TIER coverage, which by itself would be a credit negative. But, this credit negative could be mitigated if the cooperative has the flexibility to adjust rates when needed to cover changing cost levels. Old Dominion Electric Cooperative (a G&T serving Virginia, Maryland, and Delaware) is a good example of how credit negatives can be offset against credit positives. Old Dominion is rate regulated by the FERC. Old Dominion each year develops rates sufficient to achieve a TIER of 1.20x. Its FERC tariff states that if the 1.20x is not achieved, then rates can automatically be increased to achieve a 1.20x coverage. In other words, Old Dominion has accepted a fixed TIER in exchange for assurance from the regulator that a 1.20x level can be achieved on an annual basis without regulatory lag. If actual financial performance produces a TIER greater than 1.20x, then the Old Dominion member cooperatives have the option of whether to receive a refund, use the difference to mitigate other costs, or post higher margins to build equity in order to offset risk. Financial performance and the flexibility to adjust rates are intricately linked and are evaluated together.

The key in any credit evaluation is whether the credit negatives outweigh the credit positives and to what degree the lenders are exposed to a cooperative's risk.

Q. How important is it to maintain a good credit position?

A: Failure to maintain a good credit position is against the interest of consumers as well as lenders.

> "An immediate effect of low earnings and earnings of low quality is to increase the financial risks of investors, and thus lead to the downgrading of securities by the rating agencies. Downrating, in turn, means that the bonds must carry higher interest rates, a charge which is passed along to customers. Such downgrading has become a familiar phenomenon in the utility scene . . . The bonds of many utilities are now rated at levels so low that many institutional investors are barred by law from purchasing them, and interest rates must be raised in order to sell the securities within a much smaller market. These additional capital costs force rate increases which otherwise would not be necessary, without improving the financial condition of the utilities or their ability to raise money on a low cost basis. An equally serious result of limited capability to raise money is the inability of the utilities to make the investments required in order to achieve the optimum economies of service."[2]

In today's utility credit environment, the basis for capital attraction is the credit evaluation process. Whether the lenders are program lenders (CFC, CoBank), bond investors, commercial banks, or trade vendors, all rely on an evaluation of credit to determine if capital or credit should be advanced. In addition, this evaluation may also determine the nature of terms and conditions for capital or credit.

[2] Report of an Informal Task Force to the Energy Transition Team, "Recommendations for Restoration of Financial Health to the U S. Electric Power Industry" (mimeographed, December 17, 1980), pp. 11-12.

Q. You said that the first step is to determine East Kentucky's credit profile. What does it show?

A. If rated today by the three major rating agencies, East Kentucky most likely would not achieve an investment grade rating. Five years ago when East Kentucky solicited bank commitments for a five year credit revolver, the responding banks judged East Kentucky to have a credit profile in the BBB range. This assessment placed East Kentucky at the lower end of G&T credit ratings. It was critical for East Kentucky to improve its credit profile as it approached the renewal of its $650 million credit facility in 2010. In the view of some bankers responding to the 2010 solicitation, East Kentucky's credit assessment did not improve but actually deteriorated. Two of the primary banks involved in the previous syndication have currently downgraded East Kentucky to the BB+ credit level, subsequent to the release of Liberty Consulting's management audit report of East Kentucky. As a result of this assessment, these two banks have withdrawn their participation in the credit facility renewal. This is a step backwards in East Kentucky's ability to build a credit profile to attract capital.

Q. What is your recommendation regarding East Kentucky's credit condition?

A. Stronger financial performance would substantially improve East Kentucky's risk assessment and, therefore, improve its credit position. I believe East Kentucky should strive to achieve financial performance, on a consistent basis, to support a debt rating in the BBB+ to A+ rating category. This would yield the best combination of cost and flexible terms and conditions. As such, the cost of capital awarded by the Kentucky Public Service Commission should be consistent with other G&T cooperatives with ratings in the BBB+ to A+ range.

Q. Since its last rate case, has East Kentucky achieved the level of financial performance necessary to obtain capital at the most reasonable cost?

A. No, not consistently. Even though East Kentucky's financial performance improved in 2007 with a TIER of 1.43x, it declined from this level in 2008 and 2009 with TIERs of 1.25x and 1.27x, respectively. This raises the issue of East Kentucky's ability to consistently sustain margins and debt coverage at a level that would support a stronger credit profile. In East Kentucky's previous rate case, the Commission took a positive step towards improving East Kentucky's reception in the capital markets by addressing the quality of earnings issue and allowing construction interest to be recovered in rates on a current basis.

Q. Could you explain your concerns?

A. We are now in the worst credit crisis since World War II. The credit crisis has produced fewer lending institutions and substantially higher requirements to obtain credit now and in the future. The "flight to quality" has made it difficult for even "A" rated credits to borrow. While most analysts believe this condition will improve in the future, it has resulted in a tougher lending environment in 2010 than was available in 2005 when the syndicated facility was first arranged. East Kentucky is running out of time to achieve a credit profile and financial performance that would attract long-term capital on reasonable terms in the future, which will be necessary to finance future capital additions. Thus, it is critical that earnings improve in order for East Kentucky to have an opportunity to arrange capital for its generation facilities, in order to meet the power requirements of its members.

Q. How did you select the proxy group of rated G&T cooperatives?

A. I gathered information from various sources comparable to BBB+ and A+ rated G&T cooperatives from across the United States. I analyzed the data first by grouping all the BBB+ to A+ rated G&T cooperatives together and determined the average and median TIER. To remove any bias from year to year fluctuation, I averaged three years of data for the period 2006 to 2008 for each G&T cooperative. In addition, I removed the highest average TIER (Golden Spread) and the lowest average TIER (Square Butte) to further smooth the average.

Q. Would you summarize the results of your analysis?

A. Before discussing the cost of capital, it is important to acknowledge that the true cost of capital for East Kentucky is <u>not</u> the TIER of 1.05x contained in East Kentucky's debt covenant of its mortgage. This is a minimum TIER requirement with potential penalties if East Kentucky's TIER drops below this level. Most mortgages or indentures have some form of debt covenant. The lenders generally view this covenant as a market entry test that must be achieved in order to avoid default. In other words, a minimum threshold must be achieved before additional bonds can be issued. The 1.05x TIER threshold does not mean East Kentucky can actually attract capital with margins at this level. The market, after an assessment of risk as addressed above, will determine what level above 1.05x is necessary to attract capital.

Exhibit DMW-1 lists the rated G&Ts and their achieved TIER. The TIER coverage for each G&T was calculated using an average of 2006, 2007, and 2008 TIER data. In column (H) I have included only those G&Ts that are rated in the BBB+ to A+ range. This represents a reasonable credit range for East Kentucky. A review of East Kentucky's credit profile would suggest that if East Kentucky achieved financial performance similar to the "Reference G&Ts" in column (H), they would likely also have similar ratings.

The average of the earned TIERs in the reference group is 1.49x. Given East Kentucky's risk profile, it is clear to me that they should earn TIERs above the average level for these G&Ts.

Q. Would you explain why East Kentucky should earn a TIER greater than the average of this group of G&Ts?

A. As stated above, a utility's credit position is made up of credit positives and credit negatives. The debt ratings are derived by the ability of the cooperative to offset credit negatives. The cooperatives at the bottom of Exhibit 1 have a tendency to earn relatively low TIERs. In evaluating their credit, their financial performance is actually a credit negative; however, this credit negative is offset by certain significant credit positives. For example, Oglethorpe is not regulated and can adjust all its charges to its members on a monthly basis to ensure timely collection of cost. Thus, there is little risk of under-recovery of either fuel, operational, or fixed cost.

Second, several years ago Oglethorpe and its members modified their contracts, which effectively fixes the power requirements of its members from Oglethorpe. As a result of this contract change, Oglethorpe is relieved of the obligation and corresponding risk of building or acquiring power supplies to meet members' growth. Therefore, the members' load growth is the responsibility of the individual member, not the G&T.

Having the ability to immediately recover changes in cost levels and not having to incur risk related to capital acquisition are significant credit positives, thus allowing Oglethorpe to earn lower TIER's and equity ratios and still retain an "A" rating. By comparison, East

Kentucky is limited by regulation in its ability to change its rates to recover cost and also is obligated as a public service company to provide for its members' load growth. To compensate for these risks, East Kentucky must earn a higher TIER than Oglethorpe to attract capital.

To compensate for its "basket of risk" East Kentucky should earn a consistent TIER above the midpoint and average of the TIER earned by the BBB+ to A+ G&T cooperatives. To be more specific, before its next financing, East Kentucky should post annual financial performance above the average of these G&Ts on a consistent basis. This would demonstrate that East Kentucky's credit position has improved and stabilized.

Q. Was this the same methodology you used in East Kentucky's two last rate cases?

A. The methodology I used in the last two cases and this case is essentially the same. In the first case I used a three-year average of earned TIERs of G&Ts with debt ratings between BBB+ and A+ for the years of 2004, 2005, and 2006 and 2005, 2006, and 2007 in the last case. In this case I updated the data and used a three-year average of TIERs for essentially the same G&Ts for the years 2006, 2007, and 2008. As discussed below, I also expanded my testimony to show the average TIERs, DSCs, and equity ratios for cooperatives that have operating characteristics similar to East Kentucky as defined by CFC.

Q. Would you explain the additional data points for the Commission to consider in this case?

A. Yes. In addition to looking at "rated" G&Ts, the Commission may also want to consider the TIERs of both rated and unrated G&Ts with operating characteristics similar to East Kentucky. In addition, I also included average financial ratios of all G&Ts. CFC is the largest supplemental lender in the country to both distribution and G&T cooperatives.

Each year they provide East Kentucky with a comparison of East Kentucky's financial performance to that of comparable G&Ts and to the G&T population as a whole. To be consistent with my first analysis of "rated" G&Ts, I averaged the TIERs, DSCs, and equity ratios for 2006, 2007, and 2008. The results are shown on Exhibit DMW 3.

Q. Why did you include DSC ratios on Exhibit DMW-3?

A. I am not aware of any state regulatory agency that uses DSC ratios to set rates. However, it is a very important financial indicator to the banks and rating agencies in that it describes the ability, from a cash perspective, to cover both interest and principal. In dealing with banks and future bondholders, East Kentucky must achieve sufficient coverage based on both TIER and DSC.

Q. Would you explain how CFC develops its "comparison group" of G&Ts?

A. For its analysis, CFC separates the G&Ts into four groups: Generation, Purchase, Transmission, and Participation Group. East Kentucky falls in the Generation group because they generate more than 50% of their member power requirements from their owned assets. This group is made up of 21 G&Ts.

Q. How does East Kentucky's financial performance compare with the Generation group?

A. As shown on Exhibit DMW-3 the TIER for the Generation group of 1.51x, DSC of 1.21x and equity ratio of 14.57% far exceed East Kentucky's financial performance. For the same time period East Kentucky posted a TIER of 1.27x, DSC of 1.06x, and an equity ratio of 6.77%.

Q. What are the results when you compare East Kentucky to the entire population of G&Ts?

A. A comparison of East Kentucky to the group of all G&Ts is consistent with the Generation group comparison. The group making up all of the G&Ts exhibit far stronger financial performance than East Kentucky with an average TIER of 1.55x, DSC of 1.21x, and an equity ratio of over 15%.

Q. Where would you recommend the Commission actually set the TIER for making rates in this case?

A. It is exigent that East Kentucky improve its credit profile before it has to raise hundreds of millions of dollars for its next capacity addition. As was demonstrated in East Kentucky's last solicitation for its short term bank facility, a weaken credit position can be painful and expensive. From this point forward, East Kentucky must prove it can increase its equity and earn margins on a level that, at the very minimum, is equal to the average of G&Ts. My analysis has demonstrated that the average TIER for "rated" G&Ts is 1.49x while the average TIER of CFC's G&T Generation group is 1.51x and for all G&Ts is 1.55x. I could easily recommend that East Kentucky's comparatively weak equity position calls into question its ability to raise necessary capital, necessitating special consideration to allow East Kentucky to earn margins above the 1.55x level. I also understand that ratemaking is a balancing act, and that smaller steps often need to be taken which would suggest something less than a TIER of 1.55x. For setting rates, I recommend the Commission use a TIER no less than 1.50x.

Q. What comments do you have on East Kentucky's equity ratio?

A. The equity ratio is a key component of a utility's credit profile. As credit standards tighten, required equity levels will increase. Since the test period in the last rate case, East Kentucky's equity has made some improvement. However, as can be seen from

Exhibit DMW-2, the average equity level of the Reference Group of "rated" G&Ts is 17.6% compared to East Kentucky's current level of 6.8%. East Kentucky's extremely low equity level is and will continue to be a major concern to credit analysts as they advise potential bondholders. Allowing my suggested improvement in East Kentucky's earned TIER will go a long way towards improving the cooperative's equity level.

Q. Does that conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF ITS WHOLESALE ELECTRIC RATES	))))	**CASE NO. 2010-00167**

AFFIDAVIT

STATE OF VIRGINIA)
)
CITY OF RICMOND)

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

[signature]

Subscribed and sworn before me on this 20th ~~day of~~ May, 2010.

[signature]
Notary Public

My Commission expires: August 31, 2010

LI MIE WOO WARREN
COMMONWEALTH OF VIRGINIA
Reg. # 112985
August 31, 2010
NOTARY PUBLIC

East Kentucky Power Cooperative
Rated G&T Cooperatives
TIER Analysis

	Moody's (A)	S&P (B)	Fitch (C)	2006 (D)	2007 (E)	2008 (F)	Average (G)	Reference Group of BBB+ to A+ G&Ts (H)
Golden Spread	A3	A	A-	3.55x	6.01x	6.09x	5.22x	
Buckeye	**A1**	**A+**	**A+**	**2.67**	**2.40**	**1.42**	**2.16**	**2.16**
Basin	**A1**	**A+**	**AA-**	**2.04**	**1.13**	**2.59**	**1.92**	**1.92**
Tri-State	**Baa1**	**A**	**A-**	**1.11**	**1.23**	**2.09**	**1.84**	**1.84**
Brazos	---	**A-**	**A**	**2.07**	**1.76**	**1.36**	**1.73**	**1.73**
Great River	**A3**	**A-**	**A-**	**1.83**	**1.91**	**1.29**	**1.68**	**1.68**
Central Iowa	**A2**	**A**	---	**1.61**	**1.89**	**1.34**	**1.61**	**1.61**
Western Farmers	---	**BBB+**	**A-**	**1.33**	**1.58**	**1.63**	**1.51**	**1.51**
Wabash Valley	---	**A-**	---	**1.23**	**1.31**	**1.65**	**1.40**	**1.40**
Dairyland	**A3**	**A**	**A-**	**1.51**	**1.41**	**1.29**	**1.40**	**1.40**
Arkansas	**A2**	**AA-**	---	**1.53**	**1.29**	**1.34**	**1.39**	**1.39**
South Mississippi	**A3**	**BBB+**	**A-**	**1.25**	**1.42**	**1.48**	**1.38**	**1.38**
Power South	**Baa1**	**BBB+**	---	**1.29**	**1.25**	**1.42**	**1.32**	**1.32**
San Miguel	---	**A-**	---	**1.35**	**1.37**	**1.20**	**1.31**	**1.31**
Old Dominion	**A3**	**A**	**A**	**1.39**	**1.27**	**1.20**	**1.29**	**1.29**
South Texas	**A1**	**A-**	**A-**	**1.24**	**1.37**	**1.22**	**1.28**	**1.28**
Chugach Electric	**A3**	**A-**	**A-**	**1.41**	**1.12**	**1.30**	**1.28**	**1.28**
GTC	A3	AA-	AA-	1.18	1.21	1.22	1.20	
Seminole	---	**A-**	---	**1.24**	**1.18**	**1.18**	**1.20**	**1.20**
Oglethorpe	**A3(Neg.)**	**A**	**A**	**1.10**	**1.10**	**1.10**	**1.10**	**1.10**
Square Butte	---	A-	---	1.06	1.08	1.08	1.07	
Average								**1.49x**
Median								**1.40x**
East Kentucky (3 year average)								**1.27x**

Source:
- National G&T Accounting and Finance Association Handbook
- Published financial statements for Old Dominion, Oglethorpe, Basin, and Georgia Transmission (these G&Ts do not report TIER in the National G&T Accounting and Finance Association Handbook)
- Tri-State TIER data provided directly

East Kentucky Power Cooperative
Equity Ratios of Reference Group

Arkansas	41.1%
Chugach	30.3%
Buckeye	27.0%
Basin	23.8%
Tri-State	21.4%
Old Dominion	21.4%
Central Iowa	15.0%
Western Famers	14.5%
Oglethorpe	12.6%
Hoosier	12.3%
Wabash Valley	11.6%
Brazos	11.2%
Dairyland	11.1%
Great River	11.0%
Alabama	10.7%
Seminole	6.4%
Average	17.6%
Median	13.6%
East Kentucky	**6.8%**

Source:
- 2009 National G&T Accounting and Finance Association Handbook

Exhibit DMW-3

East Kentucky Power Cooperative
CFC Financial Analysis
3 Year Average (2006 – 2008)

	TIER	DSC	Equity
Generation Cooperatives*	1.51x	1.21x	14.57%
All G&Ts**	1.55x	1.21x	15.21%
East Kentucky	1.27x	1.06x	6.77%

* This group consists of 21 G&Ts that generated more than half of their power requirements

** This group consists of 60 G&Ts that are members of CFC.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-18)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to Commission Staff's Initial Request for Information dated February 18, 2011

March 18, 2011

Item 2) ***Provide Big Rivers' equity management plan. Indicate when the current plan was adopted and identify any changes made in the plan since Big Rivers' last rate case. Provide a five-year analysis of the amount of capital credits refunded to members under the plan and indicate the amounts related to general retirements and special retirements.***

Response) While Big Rivers does not have a document entitled "equity management plan", however, attached is Big Rivers "Financial Policy", policy number 104, which was approved by the Board of Directors on July 20, 2007. There have been no changes to the policy since July 20, 2007.

The financial policy incorporates the key elements of an equity management plan by covering equity levels as well as short-term and long-term access to capital markets. Additionally, financial metrics pursuant to Big Rivers' by-laws, loan covenants, and mortgage and trust indenture have been incorporated.

Item 2 b. of the financial policy directs Big Rivers to have access to sufficient low-cost capital, both short-term and long-term, by maintaining its investment grade credit rating, meeting bond covenants, adhering to indenture requirements and maintaining proper liquidity, etc.

Item 3 c. of the financial policy establishes Big Rivers' minimum equity level.

During the last five years Big Rivers has not refunded any capital credits to its Members related to general retirements or special retirements. The refunding of capital credits is governed, in part, by Section 13.15 of the indenture which reads:

Section 13.15 Distributions to Members.

The Company shall not directly or indirectly declare or pay any dividend or make any payments of, distributions of, or retirements of, patronage capital to its members (each a "Distribution") if, at the time thereof or after giving effect thereto, (i) an Event of Default shall exist, or (ii) the Company's aggregate margins and equities (determined in accordance with Accounting Requirements) as of the end of the Company's most recent fiscal quarter would be less than 20% of the Company's total long-term debt and equities (determined in accordance with Accounting Requirements) at such time; or (iii) the aggregate amount expended for all Distributions on or after the date on which the Company's aggregate margins and equities (determined in accordance with Accounting Requirements) first reached 20% of the Company's long-term debt and equities (determined in accordance with Accounting Requirements) shall exceed 35% of the aggregate net margins (whether or not such net margins have since been allocated to members) of the Company earned after such date (subtracting, in the case of any
deficit, 100% of such deficit). Notwithstanding the foregoing and so long as no Event of Default shall exist, the Company may declare and make Distributions at any time if, after giving effect thereto, the Company's aggregate margins and equities (determined in accordance with Accounting Requirements) as of the end of the Company's most recent fiscal quarter would have been not less than 30% of the Company's total long-term debt and equities (determined in accordance with Accounting Requirements) as of such date.

Witness) C. William Blackburn

Big Rivers
Electric Corporation

COMPANY POLICY

POLICY NUMBER: 104	**ORIGINAL EFFECTIVE DATE: ________**
APPROVED BY: Board	**ORIGINAL APPROVAL DATE: 7-20-07**
DATE LAST REVISED: ______	

FINANCIAL POLICY

1. Purpose

The purpose of Big Rivers Electric Corporation's ("BREC") Financial Policy is to provide a framework to enable BREC to timely meet its financial obligations and maintain its financial viability. This policy sets forth responsibilities and guidelines related to the financial management process, including key financial metrics.

The financial metrics will be pursuant to BREC's by-laws, loan covenants, mortgage, trust indenture, etc., and quantified in accordance with generally accepted accounting principles ("GAAP"). Application of this policy seeks to ensure BREC's ability to maintain the necessary financial metrics to meet its proper investment grade credit rating target and ensure its ability to timely access capital, both short-term and long-term.

2. Objectives

The overall objectives of this policy are to ensure:

a. Maintenance of the long-term financial forecasting model – BREC will maintain a financial forecast that reflects current assumptions on key modeling inputs (e.g., load, resource plans, fuel costs, financing, labor costs, etc.).

b. Timely access to capital – BREC will ensure access to sufficient low-cost capital, both short-term and long-term, by maintaining its investment grade credit rating, meeting bond covenants, adhering to indenture requirements, maintaining proper liquidity, etc.

c. Financial transparency – BREC will provide appropriate financial information in a timely manner to its stakeholders (Board, members, creditors, regulators, etc.), including financial forecasts and performance metrics.

d. Member wholesale rates – BREC will seek low-cost member wholesale rates, with minimal volatility. Management will analyze existing and alternative rate structures, seeking rational cost allocation methodology.

e. Financial analysis – As appropriate, BREC will strive to ensure accurate and consistent assumptions and methodology are employed in project evaluations, whereby such evaluations may include net present value (NPV), internal rate of return (IRR), pay-back, etc.

3. Goals

a. Member rates and margins – BREC will seek to maintain member tariff rates that enable it to meet its debt covenants and ensure that sufficient positive margins and net cash flows are generated to meet Times Interest Earned Ratio ("TIER"), Margins for Interest Ratio ("MFIR") and Debt Service Coverage Ratio ("DSCR") criteria.

b. Working capital – BREC will ensure liquidity is available to meet a minimum target of 90 days of forecasted operating expenses.

c. Equity – BREC will seek to maintain a minimum equity ratio of 20 percent to ensure its ability to maintain the targeted investment grade credit rating and ensure access to low-cost sources of capital.

d. Budgeting and capital planning – BREC will develop an annual O&M budget and capital budget and present it to the Board for approval prior to the start of the year in question. The Board will approve O&M and capital spending both through its approval of the annual budget and through specific approval of individual projects pursuant to company policy.

e. Financing – BREC will meet its capital needs through a contribution of internally generated funds and/or debt financing consistent with company policy. BREC may elect to utilize debt to finance projects based on an analysis of borrowing costs, internal rate of return, equity ratio, etc. Borrowing funds may be prudent if sufficient debt capacity exists. Regulatory, legal and reliability requirements are other important financing considerations, as is liquidity.

4. Other Relevant Company Policies

a. Financial Forecasting

1. GAAP – All forecasts will be consistent with GAAP.

2. Financial Forecast Updates – At a minimum, BREC will review and update the financial forecasting model on an annual basis. BREC will periodically update the forecast based on known changes (e.g., an approved load forecast or resource plan, timing of significant projects,

large unforeseen occurrences, etc.). The financial forecast will be reviewed and approved by the Board annually. Additionally, BREC will assess its liquidity on a monthly basis when comparing the forecast with monthly actuals.

3. Risk analysis –The financial forecasting model will have certain probabilistic capabilities to better assess risks, with output expressed in terms of key financial measures, like margins, MFIR and TIER. Risk analysis will be performed within the financial forecast and in conjunction with the APM probabilistic portfolio optimization model, which will provide key input to the financial forecast. A longer term Integrated Resource Planning ("IRP") tool will also provide key input to the financial forecast.

b. Strategic Planning and Budgeting

1. Strategic Planning – The strategic planning effort will culminate with the capital and O&M budget and the base case financial forecast. Financial modeling of alternative strategies will occur in support of on-going strategic planning. The strategic plan will be reviewed with and approved by the Board annually.

2. Budgeting – The strategic plan will drive the annual capital and O&M budgeting. The annual budget will be submitted to the Board for approval.

c. Debt Financing Sources

1. Federal Financing Bank ("FFB") supported by Rural Utilities Service ("RUS") loan guarantees

2. CoBank, National Rural Utilities Cooperative Finance Corporation ("CFC") and other similar lenders

3. The Trust Indenture should enable BREC to access the capital markets on a timely basis.

d. Interest Rate Hedging – BREC is authorized to utilize interest rate hedging instruments to effectively fix borrowing rates. While not allowed for speculative purposes, subject to Board approval BREC may hedge the risk associated with interest rate volatility for existing and proposed debt.

5. Annual Fiscal Review

The CFO shall conduct an annual fiscal review with the Board consisting of appropriate information presented in a clear and concise manner. Specific reporting requirements are as follows:

a. Cost of capital and cost of debt - Review the prior year's cost of capital and the cost of debt as defined in Appendix A (to be provided at a later date) of this policy. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

b. Capital expenditures - Review the prior year's capital expenditures and disclose the means of financing them. The Board will be apprised of BREC's equity ratio and debt capacity. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

c. Margins, equities and capital credits - Review BREC's prior year's margins, equities, capital credit allocation, and retirement of capital credits. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

d. MFIR, TIER and DSCR - Review the prior year's MFIR, TIER and DSCR as defined in Appendix A of this policy. The Board will be apprised of BREC's investment grade ratings. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

e. Working capital - Review BREC's working capital and lines of credit, assessing its liquidity. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

f. Member wholesale rates - Review the adequacy of BREC's tariff rates. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

6. Administration

The CEO and CFO shall be responsible for the administration of this policy, including 1) making periodic reports to the Board and 2) recommending changes hereto which require Board approval.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-19)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Initial Request for Information dated April 1, 2011

April 15, 2011

Item 58) ***Please provide a quantification of the amount of patronage capital available for distribution, subject to the limitations set forth in the Mortgage Indenture, at the end of each month starting with October 2010 and continuing through the most recent month for which actual information is available. Provide all assumptions, data, and computations, including electronic spreadsheets with formulas intact. The computations should include the limitations set forth in the Mortgage Indenture. This is a continuing request and the response should be supplemented as actual information for each month is available.***

Response) The pertinent language of the Indenture, dated as of July 1, 2009, and the Amended and Consolidated Loan Contract, dated as of July 16, 2009, addressing limitations on patronage capital distributions by Big Rivers is attached. The quantification shown below, of the amount of patronage capital the Indenture would permit to be distributed, utilized the most recent calendar quarter information available, as of December 31, 2010.

Quarter End Date		12/31/2010	
Equity		386,575,395.62	
Total Assets		1,472,185,126.48	
Equity/Total Assets	Loan Contract	26.26%	As Equity as a % of Total Assets is below 30%, no Distribution may be made without prior written approval of RUS.
Long-Term Debt		809,623,044.03	
Total Capitalization		1,196,198,439.65	

Equity/Total Capitalization	Indenture	32.32%	(a.) Big Rivers may not make a Distribution if it results in Equity being less than 20% as of the end of the most recent calendar quarter, or
			(b.) Big Rivers may not make a Distribution if such Distribution results in the cumulative Distributions made since Equity first exceeded 20% exceeding the cumulative Margins since that time.
Available	Indenture	39,594,091.04	(c) Notwithstanding a. or b., Big Rivers may make a Distribution to the extent the resulting % Capitalization is equal to or greater than 30%.
Resulting Equity		346,981,304.58	
Resulting Capitalization		1,156,604,348.61	
Resulting % Capitalization		30.00%	
			Conclusion: The amount available for Distribution at December 31, 2010, if RUS written approval is requested and received, was $39,594,091.04.

Per Big Rivers' Bylaws, its board of directors makes the determination whether the financial condition of Big Rivers warrants that patronage be retired, which involves a distribution. Due to Big Rivers' historical financial condition and circumstances, Big Rivers' board has not heretofore authorized the distribution of patronage capital, and has no fixed rotation policy at this time. The table above is rather straight-forward and self-explanatory, so no electronic spreadsheet is being provided.

Witness) Mark A. Hite

Execution Version

AMENDED AND CONSOLIDATED LOAN CONTRACT

Dated as of July 16, 2009

between

BIG RIVERS ELECTRIC CORPORATION

and

UNITED STATES OF AMERICA

RUS Project Designation:
Big Rivers

Section 5.20. Competitive Transition Charges

The Borrower shall not, without first complying with the requirements of Section 8.1, (i) sell, exchange or otherwise dispose of Competitive Transition Charges, (ii) request the release of Competitive Transition Charges from the lien of the Indenture, or (iii) utilize Competitive Transition Charges as a basis for issuing Obligations under the Indenture, or as basis for a securitized financing outside the Indenture, or withdraw Trust Moneys related to Competitive Transition Charges.

Section 5.21. Limitation on Release of Agreements

The Borrower shall not, without first complying with the requirements of Section 8.1, sell, assign or otherwise dispose of, request the release of or release any contract described in Section 5.6 or any Wholesale Power Contract from the lien of the Indenture.

Section 5.22. Construction Fund Trustee Account

The Borrower shall deposit the proceeds of loans made or guaranteed by RUS promptly after the receipt thereof in a bank or banks that are insured by the Federal Deposit Insurance Corporation or other federal agency acceptable to RUS. Any account (hereinafter called "Construction Fund Trustee Account") in which any such moneys shall be deposited shall be insured by the Federal Deposit Insurance Corporation or other federal agency acceptable to RUS and shall be designated by the corporate name of the Borrower followed by the words "Construction Fund Trustee Account." Moneys in any Construction Fund Trustee Account shall be used solely for the construction and operation of the System and may be withdrawn only upon checks, drafts, or orders signed on behalf of the Borrower and countersigned by an executive officer thereof.

Section 5.23. Impairment of Contracts

The Borrower shall not (a) materially breach any obligation to be paid or performed by the Borrower under, or (b) take any action which is likely to materially impair the value of, any contract which is subject to the security interest created by the Indenture.

Section 5.24. Limitations on Distributions

Without the prior written approval of RUS, the Borrower shall not in any calendar year make any Distributions to its members or stockholders except as follows:

(a) *Equity above 30%.* If, after giving effect to any such Distribution, the Equity of the Borrower shall be greater than or equal to 30% of its Total Assets; or

(b) *Equity above 25%.* If, after giving effect to any such Distribution, the aggregate of all Distributions made during the calendar year when added to such Distribution shall be less than or equal to 25% of the margins for the year to which the Distribution relates.

Provided however, that in no event shall the Borrower make any Distributions if there is unpaid when due any installment of principal of (premium, if any) or interest on its Notes, if an Event of Default has otherwise occurred and is continuing, or, if, after giving effect to any such Distribution, the Borrower's current and accrued assets would be less than its current and accrued liabilities and provided, further, that the limitation on Distributions created by this Section 5.24 shall not apply to any payments, rebates, refunds or abatement of power costs made in accordance with a Smelter Contract or made in accordance with any tariff on file with the Kentucky Public Service Commission.

Section 5.25. Limitations on Additional Indebtedness

The Borrower shall not incur, assume, guarantee or otherwise become liable in respect of any debt for borrowed money and Restricted Rentals (including Subordinated Indebtedness) other than the following ("Permitted Debt"):

(a) Additional Obligations issued in compliance with Article V of the Indenture;

(b) Purchase money indebtedness in non-System property, in an amount not exceeding 10% of Net Utility Plant;

(c) Restricted Rentals in an amount not to exceed 5% of Equity during any 12 consecutive calendar month period;

(d) Unsecured lease obligations incurred in the ordinary course of business except Restricted Rentals;

(e) Unsecured indebtedness for borrowed money, up to an aggregate amount of 15% of Net Utility Plant, so long as after giving effect to such unsecured indebtedness, the Borrower's Equity is more than 20% of its Total Assets;

(f) Debt represented by dividends declared but not paid; and

(g) Subordinated Indebtedness approved by RUS.

The Borrower may incur Permitted Debt without the consent of RUS only so long as there exists no Event of Default hereunder and there has been no continuing occurrence which with the passage of time and giving of notice could become an Event of Default hereunder. By executing this Agreement any consent of RUS that the Borrower would otherwise by required to obtain under this Section is hereby deemed to be given or waived by RUS by operation of law to the extent, but only to the extent, that to impose such a requirement of RUS consent would clearly violate federal laws or RUS Regulations.

EXECUTION VERSION

BIG RIVERS ELECTRIC CORPORATION,
GRANTOR,

to

U.S. BANK NATIONAL ASSOCIATION,
~~TRUSTEE~~

INDENTURE

Dated as of July 1, 2009

~~FIRST MORTGAGE OBLIGAT~~IONS

- THIS INSTRUMENT IS A MORTGAGE.
- THIS INSTRUMENT GRANTS A SECURITY INTEREST IN A TRANSMITTING UTILITY.
- BIG RIVERS ELECTRIC CORPORATION IS A TRANSMITTING UTILITY.
- THIS INSTRUMENT CONTAINS PROVISIONS THAT COVER REAL AND PERSONAL PROPERTY, AFTER-ACQUIRED PROPERTY, FIXTURES AND PROCEEDS.
- FUTURE ADVANCES AND FUTURE OBLIGATIONS ARE SECURED BY THIS INSTRUMENT.
- THE MAXIMUM ADDITIONAL INDEBTEDNESS WHICH MAY BE SECURED HEREUNDER IS $3,000,000,000.
- THE TYPES OF PROPERTY COVERED BY THIS INSTRUMENT ARE DESCRIBED ON PAGES 1 THROUGH 7 AND EXHIBIT A.
- THE ADDRESSES AND THE SIGNATURES OF THE PARTIES TO THIS INSTRUMENT ARE STATED ON PAGES 21, 33, 142 AND 143.

STATE TAXPAYER'S IDENTIFICATION NUMBER: 25757

FEDERAL TAXPAYER'S IDENTIFICATION NUMBER: 61-0597287

THIS INDENTURE WAS PREPARED BY JAMES M. MILLER OF SULLIVAN, MOUNTJOY, STAINBACK & MILLER, P.S.C., 100 ST. ANN BUILDING, OWENSBORO, KENTUCKY 42303, ATTORNEY FOR BIG RIVERS ELECTRIC CORPORATION.

Signed: James M. Miller

AFTER RECORDING RETURN TO:
Bryan R. Reynolds
100 St. Ann Street
Owensboro, KY 42303

OHS East:160243582.18

the obligations of the Company and the duties of the Trustee in respect of any such covenant or condition shall remain in full force and effect.

Section 13.14 Rate Covenant.

The Company shall establish and collect rates, rents, charges, fees and other compensation (collectively, "**Rates**") that, together with other moneys available to the Company, produce moneys sufficient to enable the Company to comply with all its covenants under this Indenture. Subject to any necessary regulatory approval or determination and the approval of the RUS, if required, the Company also shall establish and collect Rates that, together with other revenues available to the Company, are reasonably expected to yield a Margins for Interest Ratio for each fiscal year of the Company equal to at least 1.10 for such period. Promptly upon any material change in the circumstances which were contemplated at the time such Rates were most recently reviewed, but not less frequently than once every twelve (12) months, the Company shall review the Rates so established and shall promptly establish or revise such Rates as necessary to comply with the foregoing requirements; subject in the case of the foregoing Margins for Interest requirement to any necessary regulatory approval or determination and the approval of the RUS, if required. The Company will not furnish or supply or cause to be furnished or supplied any use, output, capacity or service of the System with respect to which a charge is regularly or customarily made, free of charge to any Person, and the Company will use commercially reasonable efforts to enforce the payment of any and all accounts owing to the ~~Company with respect to~~ the use, output, capacity or service of the System.

Section 13.15 Distributions to Members.

The Company shall not directly ~~or~~ indirectly declare or pay any dividend or make any payments of, distributions of, or retirements of, patronage capital to its members (each a "**Distribution**") if, at the time thereof or after giving effect thereto, (i) an Event of Default shall exist, or (ii) the Company's aggregate margins and equities (determined in accordance with Accounting Requirements) as of the end of the Company's most recent fiscal quarter would be less than 20% of the Company's total long-term debt and equities (determined in accordance with Accounting Requirements) at such time; or (iii) the aggregate amount expended for all Distributions on or after the date on which the Company's aggregate margins and equities (determined in accordance with Accounting Requirements) first reached 20% of the Company's long-term debt and equities (determined in accordance with Accounting Requirements) shall exceed 35% of the aggregate net margins (whether or not such net margins have since been allocated to members) of the Company earned after such date (subtracting, in the case of any deficit, 100% of such deficit). Notwithstanding the foregoing and so long as no Event of Default shall exist, the Company may declare and make Distributions at any time if, after giving effect thereto, the Company's aggregate margins and equities (determined in accordance with Accounting Requirements) as of the end of the Company's most recent fiscal quarter would have been not less than 30% of the Company's total long-term debt and equities (determined in accordance with Accounting Requirements) as of such date..

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT___(LK-20)

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

Mark Hite

file: CFC

From: Mark Bailey
Sent: Tuesday, June 02, 2009 2:58 PM
To: Berry, Bob; Albert Yockey; Bill Blackburn; David Crockett; David Spainhoward; James Haner; Mark Hite; Paula Mitchell; Travis Housley
Subject: FW: Changes to CFC Patronage Capital/Equity Retention Policies

FYI. Mark

From: Sheldon Petersen [mailto:fromthedeskofsheldonpetersen@nrucfc.coop]
Sent: Tuesday, June 02, 2009 2:17 PM
To: Mark Bailey
Subject: Changes to CFC Patronage Capital/Equity Retention Policies

National Rural Utilities Cooperative Finance Corporation

From the Desk of Sheldon Petersen

At its meeting last month, the CFC Board of Directors voted to adjust its policies relating to patronage capital retirement and equity retention in order to ensure CFC's continued strength in the capital markets during a time of increasing member demand for funding. This, of course, is in the wake of the most severe credit crisis in more than 70 years and in a climate where banks and other financial institutions are revising their capital retention policies.

Effective immediately, CFC's policy—subject to annual board authorization—will provide for the retirement of 50 percent of its allocated net margins from the prior fiscal year, with the remaining 50 percent retained for 25 years. This contrasts with the prior policy of a 70-percent immediate distribution with retirement of the remaining 30 percent in 15 years. The 25-year retention schedule also will apply to all unretired patronage capital allocations from prior years. We believe this policy change effectively balances CFC's need to retain more equity for future electric cooperative growth with our desire to provide active borrowers with an immediate return of their patronage capital.

The timing for the Board's decision on annual patronage capital retirement will remain the same. During its July meeting, the Board will review CFC's financial results and make a formal determination regarding the prior year's patronage capital retirement. Members will be notified of their exact retirement amount in late August or early September when cooperative-specific information is posted on their CFC Extranet account.

Let me say that I am proud of CFC's performance during the recent credit crisis. CFC not only maintained its strong A+ senior secured credit ratings but also significantly increased its lending to electric distribution and G&T cooperatives at a time when other financial institutions were curtailing lending. Also, I am gratified by the strong support of our members who, as of May 31, 2009, had invested a total of $278 million in CFC Member Capital Securities.

We believe that CFC's course of action, including the sales of Member Capital Securities and the modification of our patronage capital retirement policy, is a prudent and balanced approach to ensuring a vibrant CFC that will be ready and able to meet your future financing needs.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, 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.

Lane Kollen

Sworn to and subscribed before me on this
23rd day of May 2011.

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:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	CASE NO. 2011-00036
GENERAL ADJUSTMENT IN RATES	)	

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	**CASE NO. 2011-00036**

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

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 Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large industrial and Smelter customers of Big Rivers Electric Corporation, ("Big Rivers" or the "Company").

Q. What is the purpose of your testimony?

A. I am responding to Big Rivers' rate filing on a variety of cost of service and rate design issues. In this regard, I will be specifically responding to the Direct Testimony of Big River's witness Steven Seelye. Among the issues that I will address are the methodology used to allocate production demand related costs used by Mr. Seelye in his analysis. Big Rivers has utilized a 12 coincident peak ("12 CP") demand methodology to allocate production demand costs in this case. I will present the results of an alternative class cost of service study that incorporates a summer/winter 6 CP methodology, which I recommend in this case for class cost of service and to utilize in the development of a rate class revenue increase allocation.[1]

I will also address Big Rivers' proposal to move the Smelters to the midpoint of the TIER Adjustment charge for ratemaking purposes in this case. This proposal, which effectively resets the Smelter rates in this case to a $0.975/mWh TIER Adjustment level from the current $1.95/mWh amount actually paid, is not reasonable. As I will discuss, effective January 1, 2012, the Smelters will be subject to an additional $1/mWh TIER Adjustment that will potentially provide Big Rivers with an additional $7.3 million in revenues in the event that the actual Tier is projected to decline below the contractual 1.24 level. KIUC witnesses Henry Fayne and Lane Kollen will also provide testimony in support of this KIUC adjustment to the Company's filing in this case. Our position, which continues to reflect the current TIER Adjustment amounts actually paid by the Smelters during the test year and continuing through the present time, is a more reasonable basis to measure the Company's revenue requirement deficiency and the subsidies paid by Large Industrial and Smelter customers to Rural customers.

Though Big Rivers has proposed some reduction in the subsidies paid to the Rural rate class by customers on the Large Industrial rate and the Smelters, I will recommend a full elimination of present rate subsidies to Big Rivers' Rural rate class, which consists of residential, farm, small/medium commercial and small

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[1] I also present the results of an average and excess demand production cost allocation method, though I recommend the use of the 6 CP study results in this case.

industrial customers of the Company.[2] As I will discuss, given the unique characteristics of the Smelter customers, it is appropriate to fully eliminate the present rate subsidies received by the Rural rate class (for example, contractual obligations require the Smelters to pay for minimum demand and energy, regardless of actual usage; the Tier adjustment provisions of the Smelter contracts that provide financial support to Big Rivers in the form of additional revenues paid only by the Smelter customers; and the concentration risk to Big Rivers that is increased as a result of excess charges to the Smelters).[3] As discussed by other KIUC witnesses, requiring the Smelters to continue to subsidize the rest of the system is very risky because it increases the possibility of Smelter closure. As discussed by Professor Coomes, the closure of the Smelters would result in the loss of 4,700 jobs, $176 million in annual payroll and nearly $12 million annually in state and local taxes. As discussed by Dr. Morey, the closure of the Smelters would also result in $83 million in annual lost margins to Big Rivers if the Smelter load was resold in the wholesale power market. This in turn would likely trigger a massive rate increase on remaining customers, or some other drastic action.

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[2] As I discuss later in my testimony, because of the unique contractual linkage between the Smelter rates and the Large Industrial Rate, the Rural class will continue to receive millions of dollars of subsidy payments from the Smelter customers even with the KIUC proposal. As shown in Table 4 of my testimony, the Rural class will receive over $6 million in continuing subsidies under the KIUC proposed revenue increase allocation.

[3] The Rural class will continue to receive over $6 million in subsidies at proposed rates.

I will also propose mitigation measures to provide a cushion to the Rural customers as a result of the KIUC rate proposal. This mitigation proposal, which utilizes a small amount of the Rural Economic Reserve ("RER") Fund, will result in the same increase to the Rural customers as proposed by Big Rivers in this case, notwithstanding KIUC's rate class revenue increase proposal that includes the full elimination of present rate Rural subsidies (though as noted previously, over $6 million in subsidies will continue to be paid by the Smelters to the Rural class). The Commission established the RER in its Order in Case No. 2007-00455 for the purpose of mitigating future FAC and Environmental Surcharge increases for Rural customers. This use of the RER Fund would continue to only benefit Rural customers, as originally intended by the Commission. KIUC's mitigation proposal also includes a return to all Big Rivers customers of a small portion of customer capital credits currently retained by the Company. KIUC witness Lane Kollen provides the support for this proposal and I will present an illustration of the impact of Mr. Kollen's recommendation on each rate class. If Mr. Kollen's patronage capital recommendation is adopted, then the effective increase to the Rural class will be the same or lower than as proposed by Big Rivers.

The next issue that I address concerns the Company's proposed pro-forma adjustment to include $1 million of Demand Side Management ("DSM") expenditures in test year expenses. As I will discuss, Big Rivers has not developed a detailed DSM program with specific itemized budgets for its plan. Rather, the

Company is simply requesting that the Commission approve $1 million in annual revenue requirements that would be used to fund DSM programs. I will recommend that this pro-forma adjustment be rejected by the Commission and in its place the Company should propose a DSM rider that would collect actual DSM expenditures for programs approved by the Commission. Since all of these programs will be for Rural customers, the costs of these measures should be borne by the Rural rate class and not socialized to all customers, including the Smelters and Large Industrial customers, as proposed by Big Rivers in this case.

Finally, I will address a tariff issue associated with Rate LICX (Large Industrial Customer Expansion), which prices new customers or expanded loads by existing customers whose loads are 5 mW or greater at market prices, or alternatively permits Big Rivers to negotiate a special contract rate. KIUC proposes a modification to this tariff that would permit increased usage of existing customers, regardless of whether such increased usage exceeds 5 mW or not, to be served pursuant to Big Rivers' standard Large Industrial tariff.

Q. Would you please summarize your testimony?

A. Yes. I recommend and conclude the following:

- **The appropriate class cost of service study to use to allocate costs among Big Rivers' three rate classes is a 6 coincident peak study. Big Rivers plans resource additions to meet the annual summer peak load on the system. However, in recognition of the significance of winter**

peak loads as well, KIUC is recommending a summer/winter 6 CP production demand allocation methodology in this case.

- **Big Rivers' proposed pro forma adjustment to remove 50% of the Smelter TIER Adjustment revenue is not appropriate. The Company's revenue requirement deficiency and the class cost of service study should reflect the full amount of TIER Adjustment revenues paid by the Smelters during the test year in this case, and which continues through the present time. The Company's pro forma adjustment is contrary to the known and measurable fact that the Smelters continue to pay at the top of the TIER Adjustment and Big Rivers' projects that this will continue through 2012 and beyond.**

- **Based on the results of KIUC's recommended 6 CP class cost of service study, the Rural class is currently receiving (at present rates) $18.3 million annually in subsidies paid by the Smelter customers. These present subsidies should be eliminated in this rate case by assigning the first $18.3 million of the authorized Big Rivers' revenue increase to the Rural class. The remaining revenue increase should be apportioned to each of the three rate classes on a uniform percentage of base revenue basis, in a manner consistent with the terms of the Smelter Agreements that set the base rates to the Smelters at the large industrial rate computed at a 98% load factor. Under my recommendation, the Rural class will still receive an annual subsidy of $6.2 million because the Smelter base rate is contractually linked to the Large Industrial base rate.**

- **In recognition of the impact of the KIUC's proposal to fully eliminate subsidies paid to the Rural class in this case, KIUC proposes to utilize the Rural Economic Reserve fund to mitigate the increase such that the resulting Rural increase is no greater than the level proposed by Big Rivers in its rate filing. In addition, KIUC proposes to utilize a portion of the eligible patronage capital credits owed to all Big Rivers customers to further mitigate the increases in this case.**

- **Big Rivers' proposed pro forma adjustment to increase test year operating expenses for planned energy efficiency and Demand Side Management expenditures that Big Rivers plans to make (once new base rates are effective in this case) should be rejected. Instead, the Company should file a DSM cost recovery mechanism that properly tracks actual costs and assigns actual DSM expenditures to the rate classes receiving the benefits, consistent with KRS 278.285(3).**

- **Big Rivers Large Industrial Customer Expansion rate ("LICX") should be modified so that current customers can expand their existing contractual loads by 5 mW or more and continue taking service for the expanded load under the standard Large Industrial Customer rate.**

II. CLASS COST OF SERVICE STUDY ISSUES

Q. Have you reviewed the Big Rivers' class cost of service study presented by Steven Seelye in this case?

A. Yes. Big Rivers has developed a test year ended October 31, 2010 fully allocated class cost of service study that assigns the Company's revenue requirements to each of its three rate classes: Rural, Large Industrial and Smelters. As discussed by Mr. Seelye, the cost of service study initially functionalizes all of Big Rivers' costs into production and transmission functions. Production function costs are then classified as either demand related or energy related; transmission costs are all classified as demand related.

Q. Do you agree with the Big Rivers' functionalization and classification methodology?

A. Yes. Mr. Seelye's functional cost analysis and classification approach are reasonable and follow traditional cost of service methodologies used by utilities in Kentucky.

Q. How are costs allocated to Big Rivers' three rate classes in the cost of service study?

A. Big Rivers has utilized a traditional 12 coincident peak production/transmission demand allocation methodology in its recommended class cost of service study in this case. Energy related costs, primarily for fuel and purchased energy, are allocated on the basis of rate class energy use. Because Big Rivers only provides generation and transmission service, almost all of Big Rivers' revenue requirements are assigned to rate classes on the basis of 12 CP demand or mWh energy use.

Q. Do you agree with the use of a 12 CP production demand allocation methodology to assign Big Rivers' production costs to rate classes?

A. No. While the 12 CP methodology is appropriate to allocate transmission related costs, a more reasonable and accurate measure of production demand cost responsibility would be the 6 CP methodology that recognizes the significance of meeting customer loads during the three summer months and three winter months for Big Rivers. As I will demonstrate, system peak loads during the other, low load months of the year do not drive the need for generating capacity on the Big Rivers system. Big Rivers' system peaks that occur during the three summer and three winter months are predominant. This is despite the fact that the Smelter loads, which comprise a substantial part of the overall Big Rivers system, have nearly a 100% load factor.

Q. Given the Smelter load factor, why isn't it appropriate to use a 12 CP production demand method?

A. The main reason is that customer demands during the summer and winter peak months still drive the need for capacity on the Big Rivers system. Even though the off-peak months also have high system peaks, customer demands in these off-peak months are not the drivers of cost responsibility. The Big Rivers Integrated Resource Plan confirms this conclusion. Baron Exhibit__(SJB-2) contains an excerpt from the Company's 2010 IRP showing the 2010 peak demand forecast. As can be seen, Big Rivers expects to continue to be a winter peaking utility through the entire forecast horizon (2025). Both the winter and the summer peak load of the system drive the need for capacity and support the economic benefits associated with demand response programs. Essentially, at the margin, it is the winter and summer system peaks that determine the resource needs of the system.

Q. How does the fact that Big Rivers is not expecting to add new generation until 2022 impact your conclusions?

A. From a class cost of service study perspective, this does not change the "cost causative" metrics that determine the need for generation resources. First, the Company's own 12 CP study faces the identical issues, except of course that system peak loads during the off-peak months (non-winter, non-summer) do not "cause" the need for generation resources in the 2010 test year, or in 2022. Big Rivers utilizes a 14% planning reserve margin (IRP at Executive Summary page ii) applied to its annual system peak, which is the winter peak, to determine its resource needs. From a cost causation standpoint, the winter and summer peaks play a significant role in determining the resource needs of the system.

Q. Are there economic efficiency arguments that support the use of a 6 CP production demand allocation method for Big Rivers?

A. Yes. The ultimate result of a class cost of service study is to determine rate class cost of service to be used in developing rates. Rates based on cost provide appropriate economic price signals to encourage rational resource allocation. In this case, using a 6 CP demand allocation method signals to customers that customer loads during the peak winter and summer months are the principal drivers of generation resource costs on the Big Rivers' system, not customer loads at the time of the system peaks in the off-peak months of March, April, May, September, October and November. This is the same principle underlying Big Rivers proposed demand response DSM programs.

Q. Have other Kentucky utilities used the 6 CP production demand allocation methodology for class cost of service purposes?

A. Yes. In Case Number 2008-00409, East Kentucky Power Cooperative, Inc. utilized the 6 CP production demand methodology to allocate costs to rate classes. East Kentucky's cost of service study was developed and supported by Mr. Seelye, Big Rivers' witness in this case.

Q. Did you make any other changes to the Big Rivers' cost of service study?

A. Yes. In addition to the change that I made to the Company's cost of service study to use a 6 CP production demand allocator instead of the 12 CP allocator, I also revised the pro-forma revenues that Mr. Seelye calculated for the Smelter customers to place these customers at the current top of the Tier Adjustment. As discussed by Mr. Seelye in his testimony at page 24, he has pro-formed Smelter revenues during the test year to remove 50% of the current Tier Adjustment revenues. This adjustment, which reduces test year Smelter revenue in the cost of service study by $7.1 million, is not appropriate and I have eliminated this adjustment in my 6 CP cost of service analysis.

Q. Would you please explain the basis for your elimination of the Company's pro-forma adjustment to reduce test year Smelter revenues?

A. Yes. First, it would be helpful to summarize the provisions of the TIER Adjustment that apply to the Smelter customers. Pursuant to Section 4.7.1 of the Retail Electric Service Agreements ("Agreement") governing electric service to each Smelter, the Smelters are subject to a TIER Adjustment charge of up to $1.95 per mWh during the period 2008 through 2011, which includes the test year in this case. This TIER Adjustment is designed to maintain Big Rivers at a times interest earned ratio of 1.24 on an annual basis, subject to the limitation of $1.95 per mWh. As stated in Section 4.7.5 of the Agreement, the "TIER Adjustment shall be the amount of incremental revenue, whether positive or negative, calculated with respect to each Fiscal Year after determination of Net Margins for such Fiscal Year … that is necessary for Big Rivers to receive in order to achieve a TIER of 1.24 for such

Fiscal Year…" The TIER Adjustment is designed to provide some financial cushion to Big Rivers by subjecting the Smelters to additional electric rate charges.

Q. During the test year in this case (12 months ending October 31, 2010), did Big Rivers charge the Smelters a TIER Adjustment?

A. Yes. Each of the Smelters was charged the full $1.95/mWh TIER Adjustment during the test year. This $1.95/mWh TIER Adjustment increased Smelter charges during the test year by $14,229,306 and is included the test year revenues recorded by Big Rivers. Big Rivers is continuing to charge the maximum TIER Adjustment charge to the Smelters in 2011. Big Rivers' financial forecast predicts that the Smelters will be at the top of the $1.95/mWh TIER Adjustment charge for the remainder of 2011, even after this rate case. By contract, on January 1, 2012 the maximum TIER Adjustment Charge increases to $2.95/mWh. Big Rivers projects that the Smelters will be at the top of the $2.95/mWh TIER Adjustment Charge during each month of 2012. Therefore, Big Rivers' pro forma adjustment to the test year actual TIER Adjustment revenue is contrary to the facts in this record.

Q. How is Big Rivers proposing to treat these TIER Adjustment revenues in its test year revenue requirement analysis and class cost of service study filed in this case?

A. As discussed in Mr. Seelye's testimony on page 24, Big Rivers has decided to make a pro forma adjustment to eliminate 50% of the TIER Adjustment revenues actually paid by the Smelters during the test year.

Q. What is the impact of Mr. Seelye's pro forma adjustment on the class cost of service study results that he presented?

A. Reducing Smelter revenues by $7.1 million (the effect of the pro forma adjustment) has two distinct impacts. First, eliminating $7.1 million of Smelter revenue (as though it were non-recurring) increases Big Rivers' revenue deficiency because the test year at present rates has $7.1 million less in revenues to offset revenue requirements – all else being equal, this requires a larger revenue increase to meet Big Rivers' claimed revenue requirement. Second, and the issue that I address, concerns the reported test year class cost of service results, particularly the reporting of subsidies paid and received by each of Big Rivers three rate classes. Because Mr. Seelye has pro formed away $7.1 million in test year revenues actually paid by the Smelters (and continues to be paid), the rate of return reported for the Smelter class is shown to be lower than it actually was during the test year and, on a relative basis, the Rural class rate of return is shown to be higher than it actually was during the test year. The same is true for the subsidies paid by the Smelters to the Rural rate class – the actual subsidies paid by the Smelters to the Rural class are millions of dollars higher than shown in Mr. Seelye's cost of service study.

Q. What is the basis for Mr. Seelye's proposed pro forma adjustment to eliminate 50% of test year TIER Adjustment revenues?

A. Mr. Seelye argues that it is reasonable to reset the TIER Adjustment to the "middle of the bandwidth" to provide protection to Big Rivers in the form of potential additional TIER Adjustment revenues (up to $7.1 million of additional revenues) in the period following the implementation of approved rates in this case. He also states that his proposal strikes "an equitable balance in capping the additional exposure to the Smelters." Effectively, Mr. Seelye's mid-point pro forma adjustment means that the Smelters, who are currently paying the full $1.95/mWh TIER will be exposed during the rate effective period (the period after new Commission approved rates are effective) to an additional $7.1 million of TIER Adjustment. Of course, the revenue increase in this case (based on the Company's filing) includes an additional $7.1 million because of the pro forma adjustment. The Smelters would pay approximately 70% of this amount in higher base rates and then be subject to the additional $7.1 million remaining TIER Adjustment amount.

Q. Does KIUC agree with Big Rivers' "TIER Adjustment" pro forma adjustment?

A. No. There is no valid basis to "normalize" the test year by assuming that the Smelters will pay only half of the $1.95 per mWh TIER Adjustment. On the contrary, Big Rivers' proposal would create an abnormal test year for purposes of determining revenue requirements and measuring the subsidies in current rates.

First, the Smelters actually paid the full $1.95 per mWh TIER Adjustment during each month of the test year. For each of the seven months after the end of the test year the Smelters actually paid the full $1.95 per mWh TIER Adjustment. Big Rivers' projects that the Smelters will pay the full $1.95 per mWh TIER Adjustment for each of the last four months of 2011, even assuming Big Rivers has its entire proposed revenue requirement approved in this case. The Company also projects the Smelters paying the full $2.95 per mWh TIER Adjustment during each month of 2012.

Second, by setting rates in this case based on the mid-point of the TIER Adjustment, Big Rivers would effectively have an additional $7.1 million "credit card balance" at its disposal, with no Commission oversight. Big Rivers could effectively spend an additional $7.1 million and obtain an automatic rate increase from the Smelters. By setting base rates in this case using the actual test year level of TIER Adjustment payments (i.e., setting rates with the Smelters at the top of the TIER Adjustment), it provides an incentive for Big Rivers to control its expenses.

Third, while the Agreement contemplated a measure of protection from the TIER Adjustment, this cushion should not be used to eliminate spending constraints on the Company. As provided for in Section 4.7.1 of the Agreement, the TIER Adjustment limitation increases to $2.95/mWh beginning on January 1, 2012. This will provide Big Rivers with an additional $1.00/mWh beginning in 2012 that will provide up to

$7.3 million in additional revenues, should Big Rivers TIER fall below the 1.24 threshold. This additional $7.3 million in revenues will be available within four months of the establishment of new, Commission approved rates in this case. The automatic increase in the TIER Adjustment on January 1, 2012 from $1.95/mWh to $2.95/mWh, or $7.3 million per year, provides an appropriate financial cushion for Big Rivers and its creditors and strikes a reasonable balance between the financial needs of the utility and the Smelters.

Fourth, if the additional $7.3 million in TIER Adjustment revenues that will become available beginning January 1, 2012 is insufficient to produce a 1.24 TIER, given Big Rivers then current and expected costs, the Company is always able to file a base rate case seeking additional revenues.

Finally, by contract, on January 1, 2012 the rates to the Smelters will automatically be increased by $0.30/mWh, or approximately $2.2 million.[4] This $2.2 million Smelter rate increase will flow directly to the Rural and Large Industrial customer classes. This automatic Smelter rate increase (and rate reduction to other customers) was not included in Mr. Seelye's "equitable balance" discussion.

For these reasons, I have included the full $1.95/mWh TIER Adjustment revenues actually paid by the Smelters during the test year in my cost of service analysis.

Q. Have you revised Big Rivers' class cost of service study to incorporate a 6 CP production demand allocation method and the elimination of Big Rivers' proposed pro forma adjustment to the Smelter TIER Adjustment revenues?

A. Yes. Baron Exhibit__(SJB-3) provides a summary of the 6 CP cost of service study.

Q. Have you also revised Big Rivers' 12 CP cost of service study to eliminate the Company's proposed $7.1 million pro-forma adjustment?

A. Yes. For the same reasons that I have included the Smelter TIER Adjustment revenue at the full $14.2 million test year amount in my 6 CP study, I also revised Big Rivers' 12 CP study to reflect the Smelters at the top of the TIER Adjustment. Baron Exhibit__(SJB-4) presents a summary of the revised 12 CP cost of service study.

Q. How do the results of your 6 CP cost of service study and your revised 12 CP study compare to the Company's analysis?

A. Table 1, below, compares the results of the two cost of service studies, on the basis of rate of return, relative rate of return, and dollar subsidies paid (shown as a negative value) or received (shown as a positive value) at present rates.

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[4] This provision is pursuant to Section 4.11 of the Smelter Agreements.

Table 1
Big Rivers Electric Corporation
Cost of Service Study Summaries

	KIUC 6 CP COS		12 CP Adjusted*	
Rate Class	ROR	$ Subsidy**	ROR	$ Subsidy**
Rural	-2.49%	$ 18,319,114	-1.48%	$ 13,242,103
Lg Industrial	2.15%	$ 50,193	1.65%	$ 552,120
Smelter	4.89%	$(18,369,307)	4.14%	$(13,794,223)
Total	2.21%	$ 0	2.21%	$ 0

* Adjusted to reflect full $1.95/mWh Smelter Tier revenues
** Negative value indicates subsidy being paid

As can be seen in Table 1, the Rural rate class is currently receiving millions of dollars in subsidy payments from the Smelters, based on the results of either the 12 CP (with full Smelter TIER Adjustment revenues) or my recommended 6 CP cost of service analysis. The calculation of dollar subsidies paid and received by each rate class for both the 6 CP and 12 CP cost studies are shown on page 4 of Exhibits__(SJB-3) and (SJB-4).

Q. Have you prepared any alternative cost of service studies besides the 6 CP (and revised 12 CP) studies?

A. Yes. I have also prepared an Average and Excess Demand ("A&E") cost of service study that uses an A&E allocator to assign production demand costs to rate classes. As in the case with the 6 CP study that I presented, the A&E cost study adopts Big

Rivers cost of service study allocations for all costs except production demand and reflects the full TIER Adjustment revenue paid by the Smelters. The results of the A&E study are presented in Baron Exhibit__(SJB-5) and summarized in Table 2 below.

Table 2
Big Rivers Electric Corporation
Cost of Service Study Summary

	Average & Excess COS*	
Rate Class	ROR	$ Subsidy**
Rural	-2.87%	$ 20,474,819
Lg Industrial	1.40%	$ 815,566
Smelter	5.40%	$ (21,290,385)
Total	2.21%	$ (0)

* Adjusted to $1.95/mWh Smelter Tier revenues
** Negative value indicates subsidy being paid

As is the case with the 12 CP and 6 CP cost of service studies, the Rural rate class is receiving substantial dollar subsidies paid for by the Smelter customers. While I am not recommending that the Commission adopt the A&E cost of service study in this case, the results confirm that Rural customers (including residential customers, farms, small commercial customers, medium commercial customers and small industrial customers), are paying rates substantially below cost of service and receiving million of dollars in subsidies from the Smelter customers.

III. ALLOCATION OF THE REVENUE INCREASE TO RATE CLASSES

Q. Have you reviewed Big Rivers' proposed allocation of its requested $39.9 million revenue increase to rate classes?

A. Yes. As discussed by Mr. Seelye beginning on page 18 of his testimony, the Company attempted to allocate the revenue increase in this case by narrowing the "gap between the rate of return shown in the cost of service study for the Rurals and the rate of return for the Large Industrials." (Seelye testimony at page 18, line 8). Based on Big Rivers' 12 CP class cost of service study, the Rural rate class received $11 million in subsidies from the Large Industrial class and the Smelter class in the test year. This $11 million, which is Big Rivers' own calculation, represents the difference between the amount that the Rural customers paid and the costs of providing service to these customers. Rates to Rural customers, as proposed by the Company, would reduce this $11 million subsidy to $9.2 million.[5]

Q. Do you agree with Big Rivers' proposed allocation of its requested overall revenue increase to the Rural rate class?

A. No. First, as I discussed in the prior section of my testimony, the actual subsidy received by the Rural rate class is $18.3 million, not $11 million. The $18.3 million

[5] As noted in my Table 1, the Big Rivers' 12 CP cost of service study shows that the Rural customers are receiving $13 million in subsidies from the Smelters at present rates, when the Smelter Tier Adjustment is reflected at test year levels.

subsidy amount is based on the results of a 6 CP class cost of service study, and the elimination of the Company's proposed $7.1 million pro forma reduction to test year actual Smelter revenues. Even using Big Rivers' proposed 12 CP class cost of service methodology the Rural subsidy at present rates is $13.2 million, when test year actual Smelter TIER Adjustment revenues are used.

Q. Setting aside the issue of the amount of subsidy received by the Rural rate class, is it reasonable to continue having the Smelters pay millions of dollars of subsidies to the Rural class?

A. No. As shown in my Table 1, the Smelters are paying subsidies of $18.3 million at present rates. Almost the entirety of this amount is going to the Rural class (99.7%). These subsidies should be eliminated in this rate case for a number of policy reasons. First, to the extent that there exists concentration risk for Big Rivers associated with serving the two Smelter customers, this risk is exacerbated by piling on an additional $18.3 million in revenues from these two customers, while significantly understating the cost to serve the Rural class. Effectively, Big Rivers is asking the Smelters to pay its cost of service, plus an additional $18.3 million subsidy payment, thus concentrating a larger share of the Company's revenues in the Smelter class than can be justified on the basis of cost. As discussed by KIUC witness Fayne, Big Rivers' Rural rates are among the lowest in Kentucky and the surrounding region. Even after the increase in this case, these rates will continue to be lower than most other comparable utility rates. From a public policy standpoint, the large Rural subsidies should be removed going forward.

Also, as discussed by Mr. Fayne, the Big Rivers' Smelter rates are at the top of the range of comparable aluminum smelter rates in the world. To the extent that aluminum supply exceeds demand at some point in the future, I am informed by Smelter management that the highest cost production facilities will be the first to a curtailment. To the extent that eliminating subsidies from the Smelter rates can provide some mitigation to the high electric rates facing the Kentucky smelters (relative to worldwide Smelter rates), this would produce economic benefits to the State. Finally, as I will discuss subsequently, the KIUC proposal to eliminate Rural subsidies is coupled with a rate mitigation plan that will result in increases to Rural customers at the same level as proposed by Big Rivers in this case.

Requiring the Smelters to continue to subsidize the rest of the system is highly risky because it increases the potential of Smelter closure. As discussed by Professor Coomes, the closure of the Smelters would result in the loss of 4,700 jobs, $176 million in annual payroll and nearly $12 million annually in state and local taxes. As discussed by Dr. Morey, the closure of the Smelters would also result in $83 million in annual lost margins to Big Rivers, if Big Rivers was forced into becoming a merchant generator and the Smelter load was resold in the wholesale power market. This in turn would likely trigger a massive rate increase on remaining customers, or some other drastic action. Continuing reliance on the Smelters to subsidize the residential, farm, commercial and small industrial customers is a bad public policy that could have severely negative consequences for the economy of Western Kentucky, other ratepayers, the creditors of Big Rivers and Big Rivers itself.[6]

Q. Would you please discuss KIUC's recommended methodology to allocate the Commission approved revenue increase in this case to the Rural, Large Industrial and Smelter rate classes?

A. Baron Exhibit__(SJB-6) contains KIUC's proposed revenue increase allocation analysis. The first step in the analysis is to calculate the amount of the subsidies at present rates paid by each rate class using the results of KIUC's recommended 6 CP class cost of service study. This is shown on Line 4 of the exhibit. As I discussed earlier, the subsidy payments made by the Smelters to the Rural class is $18.3 million, based on present rates. KIUC's proposal is to fully eliminate this current subsidy by assigning the first $18.3 million of KIUC's overall proposed $18.679 million revenue increase to the Rural class. This is shown on Line 6 of the exhibit.

Q. How is the remainder of the revenue increase (after eliminating the present Rural subsidies) allocated to rate classes?

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[6] As noted previously, even under the KIUC proposal, the Smelters will continue to pay substantial subsidies to the Rural class.

A. This allocation is shown on Line 16 of the exhibit. The remaining increase of \$0.360 million is allocated to the three rate classes on the basis of present base rate demand/energy revenues for the Rural and Large Industrial Class and the Smelter base energy charge revenues, reflecting the Large Industrial rate computed at a 98% load factor. Using this relationship, I develop an allocator shown on Line 12 of my exhibit. The resulting allocation of the remaining increase (after eliminating the current Rural subsidy) is shown on Line 13 of my exhibit. Finally, Line 15 shows KIUC's proposed increases to each rate class, before mitigation.

Q. Would you please describe KIUC's rate mitigation proposal?

A. KIUC is proposing two separate and distinct mitigation adjustments in this case. The first adjustment utilizes the RER fund to mitigate the KIUC recommended increase to the Rural class such that the resulting increase after mitigation will be equal to the Rural revenue increase proposed by Big Rivers in this case. As shown on Baron Exhibit__(SJB-6) at Line 15, KIUC's recommended Rural increase, before mitigation is \$18.4 million. Based on Mr. Seelye's Exhibit 6, page 1 of 3, Big Rivers is proposing a base rate increase to the Rural class of \$14.172 million. To fully mitigate KIUC's increase and bring it to the level proposed by Big Rivers in this case, \$4.2 million of the RER fund would be required annually. This is shown on Lines 16 and 17 of my exhibit. The resulting Rural base revenue increase is now \$14.172 million, the amount proposed by the Company in this case.

Q. What is the basis for your proposal to utilize the RER fund to mitigate the Rural base rate increase in this case?

A. As I discussed earlier, the Commission established the RER in its Order in Case No. 2007-00455 for the purpose of providing rate mitigation for Rural customers. While the Commission Order intended that the fund be used to mitigate the impact of future FAC and Environmental Surcharge increases, the intent of the Commission established fund was to benefit Rural customers. The KIUC proposal continues to apply the fund strictly for the benefit of Rural customers. KIUC believes that our proposal provides a reasonable application of this fund to partially offset the test year level of subsidies that are being paid by Smelter customers to the Rural rate class, which includes not only residential and farm customers, but also small and medium commercial customers and small industrial customers as well. Based on Big Rivers' response to KIUC 1-64, the balance in the RER fund will be $63 million by the time new rates in this case become effective in September 2011. Based on Big Rivers' projections, the RER would not be required to mitigate FAC and Environmental Surcharge increases until mid-2015. The RER fund is projected to be fully utilized by early 2018. Assuming that the KIUC proposal is adopted by the Commission, the annual withdrawal beginning in late 2011 would be about $4.2 million annually, resulting in a full utilization of the fund by late 2016 or early 2017.

Q. Would you describe the second mitigation part of the KIUC mitigation proposal?

A. Yes. This proposal, which is addressed in KIUC witness Kollen's testimony, would utilize Big Rivers' patronage capital, to the maximum extent possible, to partially offset a portion of the remaining Rural increase, as well as KIUC proposed increases to the Large Industrial and Smelter classes. Based on Mr. Kollen's proposal, patronage capital distributions, to the maximum extent possible, would be used to offset the increases to each customer class. An illustration of the impact of this proposal is shown on Line 18 of Baron Exhibit__(SJB-6). The net impact on each customer class is shown on Line 19 of the exhibit. Also shown in Exhibit (SJB-6) are the percentage increases, including the effect of the Non-FAC PPA Amortization and the effect of lowering the Non-FAC PPA base. These presentations correspond to the presentation shown in Mr. Seelye's Exhibit 6, page 1 of 3. A summary of the exhibit is shown in Table 3 below.

Table 3
KIUC Proposed Rate Increases

	Total System	Rurals	Large Industrials	Smelters
Subsidy at Present Rates	-	(18,319,114)	(50,193)	18,369,307
KIUC Proposed Revenue Increase	**18,679,000**			
Eliminate Subsidy to Rurals	18,319,114	18,319,114	-	-
Spread of Increase Remainder	359,886	98,395	34,009	227,482
Step 1 Increase - Rurals Subsidy	18,319,114	18,319,114	-	-
Net Increase	18,679,000	18,417,509	34,009	227,482
Rural Mitigation from RER Fund	(4,245,506)	(4,245,506)	-	-
Net Increase after Mitigation		14,172,003	34,009	227,482
Patronage Capital Distribution	(2,708,000)	(621,285)	(235,635)	(1,851,080)
Final Effective Base Rate Increase		13,550,718	(201,626)	(1,623,598)
Percent Increase		12.26%	-0.51%	-0.57%

As can be seen in Table 3, depending on the actual amount of patronage capital actually distributed, KIUC is proposing slight decreases to the Smelter and Large Industrial class of about 0.5%, while the Rural class would receive an increase of about 12%, which is less than the Rural increase proposed by Big Rivers.

Q. Does the KIUC proposal fully eliminate subsidies in proposed rates?

A. No. While the KIUC proposal is designed to fully eliminate the $18.3 million in present rate subsidies received by the Rural class and paid by the Smelters, substantial subsidies will continue to be received by Rural customers at proposed rates. Baron Table 4 below shows the calculation of subsidies at proposed rates based on the KIUC recommended revenue increases.

	Table 4 Subsidies Remaining at Proposed Rates	Total System	Rurals	Large Industrials	Smelters
1	Rate Base - 6 CP	1,170,341,502	390,335,625	96,406,419	683,599,459
2	Net Utility Operating Margin	25,806,684	(9,711,995)	2,075,623	33,443,057
3	Return on Rate Base	2.21%	-2.49%	2.15%	4.89%
4	Subsidy at Present Rates	-	(18,319,114)	(50,193)	18,369,307
5	**Adjusted Total Increase Required**	**18,679,000**			
6	Eliminate Rural Subsidy	18,319,114	18,319,114		
7	Spread of Increase Remainder	359,886	98,395	34,009	227,482
	Step 1 Increase - Rurals Subsidy	18,319,114	18,319,114	-	-
8	**Net Increase**	**18,679,000**	**18,417,509**	**34,009**	**227,482**
9	Income at Proposed Rates (line 2 + line 8)	44,485,684	8,705,513	2,109,631	33,670,539
10	ROR - Proposed Rates (line 9/line 1)	3.80%	2.23%	2.19%	4.93%
11	Net Utility Operating Margin at System ROR	44,485,684	14,836,992	3,664,491	25,984,202
12	**Subsidy at Proposed Rates (line 11 - line 9)**	-	**6,131,478**	**1,554,859**	**(7,686,338)**

Q. Why do subsidies continue at proposed rates under the KIUC proposal?

A. The subsidies will continue because the Smelters continued to pay $18.369 million of subsidies at present rates – as shown on Line 4 of the table; only the Rural subsidies received were eliminated in our proposal. Under normal circumstances, subsidies for all rate classes would be eliminated on Line 4 – in this case the Smelters would have received an $18.369 million rate reduction in the first step of the revenue apportionment. Had this been done, the full $18.679 million revenue increase would then have been spread on adjusted base revenues on Line 7 and most of the resulting subsidies at proposed rates would have been eliminated. The only remaining subsidies would be due to the use of base revenues to spread the "remaining increase" on Line 7; rather than rate base which is the basis for computing rate of return.

Q. Are you recommending that all subsidies be eliminated?

A. No. The Smelter Agreement requires that Smelter rates be tied to Large Industrial rates. As a result, the KIUC proposal reflects a continuation of some subsidies being paid by the Smelters to the Rural rate class. However, to the extent that subsidies remain, even after the KIUC proposals in this case, this result reflects a measure of ratemaking gradualism that is further enhanced by the proposals to utilize the RER fund and the use of a portion of patronage capital to offset the impact of the rate increase.

IV. PROPOSED ENERGY EFFICIENCY AND DSM PRO FORMA ADJUSTMENT

Q. Would you please address the Company's proposed $1.0 million pro forma adjustment to increase test year expenses for energy efficiency and demand side management (collectively referred to as "DSM") programs that Big Rivers plans to pursue in the future?

A. Yes. As described in the Direct Testimony of Big Rivers' witness William Blackburn beginning on page 32, Big Rivers has included the $1.0 million pro forma adjustment to recover expenditures that the Company plans to make following the implementation of an approved base rate increase in this case.

Q. Does Big Rivers have a specific DSM plan associated with the $1.0 million pro forma increase to test year expenses?

A. No. While Mr. Blackburn states that the DSM programs were outlined in the Company's 2010 Integrated Resource Plan ("IRP"), the Company has not developed a specific plan and cannot provide detailed specifics of the expenditures that are included in the requested $1.0 million expense pro forma. In response to KIUC 2-1, Mr. Blackburn states as follows:

> Big Rivers has budgeted amounts for energy efficiency and DSM programs for 2011 and 2012, but cannot provide detailed descriptions, monthly tasks, capital expenditures or expenses as requested since these programs are still in the early stages of development, with short-term pilot programs either underway or in the planning phase.

While the Company was able to provide descriptions of the pilot programs that it is working on, there are no specific plans or expenditures that can be tied to its request for $1.0 million in the test year. I have included a copy of Big Rivers' response to the KIUC data request as Baron Exhibit__(SJB-7).

Q. Are the proposed DSM programs designed primarily for the Rural rate class?

A. Yes. While Big Rivers states that its intention is to have programs for Commercial and Industrial customers as well (lighting, HVAC), based on the response to KIUC 2-1, most of the programs are for the Rural class. None of the programs are for the Smelter customers.

Q. Given that Big Rivers does not have a well defined DSM plan and cannot tie its expenditures to the requested $1.0 million pro forma expense, should the pro forma adjustment be accepted by the Commission?

A. No. First, because of the uncertainty associated with DSM expenditures that might be incurred in the future, it is inappropriate to include the $1.0 million expense in the Company's test year. This is not a known and measureable expense. Second, since most of the planned programs appear to be for the Rural class, and none for the Smelter customers, it is appropriate to specifically recover the actual expenditures from the customers that benefit from the programs. The most appropriate mechanism to accomplish this would be a DSM cost recovery mechanism. As indicated in Big Rivers' response to KIUC 2-3, the Company "does not have a strong objection to recovering costs through a DSM cost recovery mechanism." I recommend that Big Rivers file such a recovery mechanism in its rebuttal testimony and that the Commission deny base rate recovery of the $1.0 million DSM pro forma expense. I have attached the Company's response to KIUC 2-3 in Baron Exhibit__(SJB-8).

Q. Are there any additional reasons to use a DSM recovery mechanism instead of base rates to recover actual DSM costs from customers?

A. Yes. KRS 278.285 (3) specifically requires that the Commission allocate the costs of DSM programs to the rate class that receives benefits from the program. Specifically, the statute states as follows:

> (3) The commission shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs. The commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

In addition, individual industrial customers are permitted to develop their own individual DSM programs and avoid any allocation of general DSM costs from a utility. Big Rivers' proposed DSM pro forma adjustment does not meet the policy standards established by the Legislature because it is included in base revenue requirements. The most appropriate method to implement DSM cost recovery is through a separate mechanism that can be structured to meet the needs of specific customer classes and avoid cost allocations that are improper.

V. TARIFF ISSUES

Q. Have you identified any specific tariff issues that should be addressed in this case?

A. Yes. Big Rivers currently requires existing large industrial customers whose loads increase, due to expansion, by 5 mW or more, to take service under Rate LICX (Large Industrial Customer Expansion). This tariff also applies to new loads of 5 mW or more as well. Unlike the standard Large Industrial Customer rate ("LIC"), Rate LICX prices expansion power at the price Big Rivers pays for purchases from third-party suppliers. Essentially, this is a market-based rate which was initially established prior to the Unwind when Big Rivers leased its generation to LG&E Energy/E.ON. While the tariff permits Big Rivers to negotiate an alternative contract rate with such a customer, there is nothing in the tariff that requires such a contract or defines its terms, conditions or pricing basis.

Q. Are these LICX provisions reasonable for an existing large industrial customer that may want to expand production?

A. No. While I do not object to the LICX tariff per se, I do not believe that it should be applicable to existing large industrial customers that may want to expand their usage of power from Big Rivers. The terms of the tariff act to deter economic development and the potential creation of new jobs in Kentucky. Existing customers that may want to expand in Kentucky effectively are forced to take market prices, rather than a standard cost based tariff. This may have been appropriate when Big Rivers' generation was leased, but it is not appropriate now. While it could be argued that the LICX rate deters new loads and the jobs that such customers may bring to the state, I am only recommending in this case that existing customers be permitted to take expansion service for 5 mW or more contractual load increases under the existing LIC rate. My recommendation would apply to customers with self generation or cogeneration, unlike the current tariff. Baron Exhibit__(SJB-9) contains a redlined version of Big Rivers' Schedule LICX reflecting the changes that I am recommending.

Q. Does that complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBITS

OF

STEPHEN J. BARON

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	CASE NO. 2011-00036
GENERAL ADJUSTMENT IN RATES	)	

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 May 2011

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 May 2011

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 May 2011

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
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Stephen J. Baron
As of May 2011

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.

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As of May 2011

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.

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of
Stephen J. Baron
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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	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
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
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Stephen J. Baron
As of May 2011

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 May 2011

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 May 2011

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
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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
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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
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As of May 2011

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.

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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
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As of May 2011

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. 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 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 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities 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. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. 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 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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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.

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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
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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
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Stephen J. Baron
As of May 2011

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
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	CASE NO. 2011-00036
GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC

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PUBLIC SERVICE COMMISSION

Case No 2010 00443

November 12, 2010

Jeff DeRouen
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Big Rivers Electric Corporation's 2010 Integrated Resource Plan

Dear Mr. DeRouen:

Enclosed in connection with the 2010 Integrated Resource Plan ("IRP") of Big Rivers Electric Corporation are the following:

1. Petition of Big Rivers Electric Corporation for confidential treatment of portions of its 2010 IRP;

2. One sealed and bound copy of the IRP with the confidential material highlighted or on a CD marked confidential;

3. Ten copies of the IRP with the confidential material redacted; and

4. One additional, unbound copy of the IRP with the confidential material redacted.

Although there were no intervenors to the proceeding regarding Big Rivers' 2005 IRP, that proceeding was dismissed without a review of the IRP. Therefore, a copy of the items listed in this letter, and attachments, have been served on each of the parties to the 2002 Big Rivers' IRP proceeding, as shown on the attached service list. If you have any questions regarding this filing, please do not hesitate to contact Albert Yockey, VP Governmental Relations & Enterprise Risk Management at Big Rivers, or me.

Sincerely yours,

TAK

Tyson Kamuf

TAK/ej
Enclosures

cc: w/enclosures: Service List
Sanford Novick
Burns Mercer
Kelly Nuckols

Telephone (270) 926-4000
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100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

Table 7.1: Historical and Projected Power Requirements

	2009 Load Forecast			*2010 Load Forecast /IRP*		
	Total Energy Requirements (MWH)	*Winter Peak Demand (MW)*	*Summer Peak Demand (MW)*	*Total Energy Requirements (MWH)*	*Winter Peak Demand (MW)*	*Summer Peak Demand (MW)*
2005	*10,603,749*	*1,413*	*1,469*	*10,603,749*	*1,413*	*1,469*
2006	*10,609,828*	*1,414*	*1,486*	*10,609,828*	*1,414*	*1,486*
2007	*10,697,157*	*1,467*	*1,511*	*10,697,157*	*1,467*	*1,511*
2008	*10,747,493*	*1,476*	*1,475*	*10,747,493*	*1,476*	*1,475*
2009	*10,724,973*	*1,494*	*1,488*	*9,856,285*	*1,536*	*1,469*
2010	*10,757,127*	*1,499*	*1,492*	*10,695,669*	*1,496*	*1,478*
2011	*10,791,625*	*1,505*	*1,498*	*10,729,241*	*1,498*	*1,485*
2012	*10,846,240*	*1,512*	*1,505*	*10,782,940*	*1,504*	*1,491*
2013	*10,857,274*	*1,518*	*1,511*	*10,793,126*	*1,510*	*1,497*
2014	*10,893,049*	*1,525*	*1,517*	*10,827,941*	*1,517*	*1,503*
2015	*10,933,548*	*1,533*	*1,525*	*10,867,352*	*1,525*	*1,511*
2016	*10,993,876*	*1,541*	*1,533*	*10,926,611*	*1,533*	*1,519*
2017	*11,020,338*	*1,550*	*1,541*	*10,951,812*	*1,542*	*1,527*
2018	*11,066,160*	*1,559*	*1,550*	*10,996,403*	*1,551*	*1,536*
2019	*11,112,553*	*1,568*	*1,559*	*11,041,551*	*1,560*	*1,544*
2020	*11,173,608*	*1,576*	*1,567*	*11,101,517*	*1,568*	*1,552*
2021	*11,200,827*	*1,586*	*1,576*	*11,127,454*	*1,578*	*1,561*
2022	*11,245,989*	*1,594*	*1,584*	*11,171,403*	*1,587*	*1,569*
2023	*11,290,709*	*1,603*	*1,592*	*11,214,923*	*1,595*	*1,578*
2024	*n/a*	*n/a*	*n/a*	*11,278,601*	*1,604*	*1,586*
2025	*n/a*	*n/a*	*n/a*	*11,323,317*	*1,613*	*1,595*

Note: Shaded year represents base year in each forecast.

Table 5.1: 2010 Load Forecast/IRP

	Total Energy Requirements (MWH)	*Winter Peak Demand (MW)*	*Summer Peak Demand (MW)*
2005	*10,603,749*	*1,413*	*1,469*
2006	*10,609,828*	*1,414*	*1,486*
2007	*10,697,157*	*1,467*	*1,511*
2008	*10,747,493*	*1,476*	*1,475*
2009	*9,856,285*	*1,536*	*1,469*
2010	*10,695,669*	*1,496*	*1,478*
2011	*10,729,241*	*1,498*	*1,485*
2012	*10,782,940*	*1,504*	*1,491*
2013	*10,793,126*	*1,510*	*1,497*
2014	*10,827,941*	*1,517*	*1,503*
2015	*10,867,352*	*1,525*	*1,511*
2016	*10,926,611*	*1,533*	*1,519*
2017	*10,951,812*	*1,542*	*1,527*
2018	*10,996,403*	*1,551*	*1,536*
2019	*11,041,551*	*1,560*	*1,544*
2020	*11,101,517*	*1,568*	*1,552*
2021	*11,127,454*	*1,578*	*1,561*
2022	*11,171,403*	*1,587*	*1,569*
2023	*11,214,923*	*1,595*	*1,578*
2024	*11,278,601*	*1,604*	*1,586*
2025	*11,323,317*	*1,613*	*1,595*

The forecast is heavily influenced by the large Commercial and Industrial ("C&I") class, which represents approximately two-thirds of total system peak demand and energy requirements. Energy and peak projections for the large C&I class include only those customers that are currently on line, and energy and peak values are held constant at 2009 levels. No new customers, and no new growth in energy sales and peak demand for existing customers in the class, are included in the forecast.

Growth in the number of customers for the residential class is influenced by increases in the number of households, which is projected to increase at an average rate of 0.5% per year through 2025. Growth in the number of small commercial customers is driven by employment, which is also projected to increase at an average rate of 0.5% per year.

Average household consumption is projected to show very little growth in future years. Factors limiting growth in consumption include: increases in price, continued replacement of older inefficient appliances with newer high efficient units, continued decline in the number of people per household, and increases in building efficiencies and general consumer conservation awareness. Factors contributing to increases in average household consumption include: larger homes, increases in safety issues at the Wolf Creek and Center Hill Dams, near Jamestown, Kentucky, and Lancaster, Tennessee, respectively, on the Cumberland River System. Currently SEPA is providing a run-of-river schedule. During the time the force majeure has been in effect, the run-of-river schedule has provided up to approximately 100 MW. Based on current estimates from the Army Corps of Engineers, which is responsible for repairs, the termination of the force majeure, and hence the ability of Big Rivers to schedule its full SEPA allocation of 178 MW, is expected to occur in mid-year 2013. The lower capacity currently available from Reid 1 and SEPA reduces Big Rivers' total of 1,829 MW by 93 MW to a current total capacity of 1,736 MW.

- Big Rivers owns and operates a transmission system containing 1,262 miles of transmission line and 80 substations.
- Big Rivers' Equivalent Forced Outage Rate[2] ("EFOR") was 3.7% in 2009. The industry average for comparable generating units is 6.9%, according to the North American Electric Reliability Corporation ("NERC").
- The system peak demand is projected to grow by 117 MW from 2010 through 2025, reaching 1,613 MW (0.5% average annual growth).
- The resource assessment analysis was produced using a minimum reserve margin criteria equal to 14%. The selection of this value was based on NERC's suggested 15% reserve margin target for predominantly thermal systems. A minimum of 14% was used to recognize that actual margins could vary above and below the target over the term of the IRP. [redacted]
- Big Rivers plans to launch Energy Efficiency Programs beginning in 2011. For the IRP study, a case representing 2011 expenditures of $1 million on DSM is assumed. The programs under this case are expected to save a cumulative 49,160 MWh by 2025, with a 14 MW reduction in winter peak demand and a 10 MW reduction in summer peak demand[3]. The programs may include, but are not limited to:
    - Residential Efficient Lighting Program
    - Residential Efficient Products Program
    - Residential Advanced Technologies Program
    - Residential Weatherization Program

[2] The percentage of time a generating unit is off-line unexpectedly.
[3] Savings would vary based on expenditure levels for EE programs. For details on savings estimates, see Section 8.3(e) and Appendix B herein.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
6 CP - Smelter TIER Adjustment - Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 110,934,700	$ 39,110,620	$ 282,406,135	$ 432,451,455
Off System Sales Revenue			OSSALL	$ 12,751,365	$ 4,563,381	$ 59,229,055	$ 76,543,801
Income from Leased Property Net		OTHREV	RBPLT	$ 49,919	$ 12,329	$ 87,424	$ 149,673
Other Operating Revenue & Income		OTHREV	RBPLT	$ 4,595,526	$ 1,135,019	$ 8,048,200	$ 13,778,745
Total Operating Revenues		TOR		$ 128,331,510	$ 44,821,350	$ 349,770,815	$ 522,923,675
Operating Expenses							
Operation and Maintenance Expenses				$ 120,514,880	$ 39,518,059	$ 286,404,608	$ 446,437,546
Depreciation and Amortization Expenses				$ 11,430,505	$ 2,820,170	$ 19,985,334	$ 34,236,009
Property and Other Taxes			NPT	$ (31,650)	$ (7,782)	$ (55,131)	$ (94,563)
Total Operating Expenses		TOE		$ 131,913,735	$ 42,330,446	$ 306,334,811	$ 480,578,992
Utility Operating Margin				$ (3,582,224)	$ 2,490,903	$ 43,436,004	$ 42,344,683
Non-Operating Items							
Interest Income			RBPLT	$ -	$ -	$ -	$ -
Other Non-Operating Income			RBPLT	$ -	$ -	$ -	$ -
Other Credits			RBPLT	$ -	$ -	$ -	$ -
Interest on Long Term Debt				$ -	$ -	$ -	$ -
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ -	$ -	$ -	$ -
Total Non-Operating Items				$ -	$ -	$ -	$ -
Net Utility Operating Margin		TOM		$ (3,582,224)	$ 2,490,903	$ 43,436,004	$ 42,344,683
Net Cost Rate Base				$ 390,335,625	$ 96,406,419	$ 683,599,459	$ 1,170,341,502

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
6 CP - Smelter TIER Adjustment - Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue				$ 128,331,510	$ 44,821,350	$ 349,770,815	$ 522,923,675
Pro-Forma Adjustments:							
To annualize revenue for new industrial customer	2.01			$ -	$ 149,752	$ -	$ 149,752
To adjust mismatch in fuel cost recovery	2.02	FACREV		$ (25,166,503)	$ (9,525,471)	$ (73,123,203)	$ (107,815,177)
To eliminate Environmental Surcharge revenues	2.03	ESREV		$ (5,315,462)	$ (2,025,233)	$ (15,493,538)	$ (22,834,232)
To reflect temperature normalized sales volumes	2.04		EnergyR	$ (421,610)	$ -	$ -	$ (421,610)
To eliminate Non-FAC PPA revenues	2.05	NFPR		$ 2,757,108	$ 1,045,800	$ 7,785,109	$ 11,588,017
To eliminate WKEC Lease Expenses	2.19		RBPLT	$ (49,919)	$ (12,329)	$ (87,424)	$ (149,673)
To eliminate RRI Domtar Cogen Backup revenues	2.09			$ -	$ (1,115,159)	$ -	$ (1,115,159)
To adjust for Smelter TIER Adjustment Charge	2.22			$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 100,135,124	$ 33,338,709	$ 268,851,759	$ 402,325,592

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
6 CP - Smelter TIER Adjustment - Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 120,514,880	$ 39,518,059	$ 286,404,608	$ 446,437,546
Depreciation and Amortization Expenses				$ 11,430,505	$ 2,820,170	$ 19,985,334	$ 34,236,009
Property and Other Taxes			NPT	$ (31,650)	$ (7,782)	$ (55,131)	$ (94,563)
Adjustments to Operating Expenses:							
To annualize expenses for new industrial customer	2.01			$ -	$ 110,607	$ -	$ 110,607
To adjust mismatch in fuel cost recovery	2.02		FACREV	$ (25,685,949)	$ (9,722,081)	$ (74,632,493)	$ (110,040,523)
To eliminate Environmental Surcharge expenses	2.03		ESREV	$ (5,462,944)	$ (2,081,425)	$ (15,923,422)	$ (23,467,791)
To reflect weather normalized sales volumes	2.04		EnergyR	$ (295,293)	$ -	$ -	$ (295,293)
To eliminate Non-FAC PPA expenses	2.05		NFPR	$ 2,858,740	$ 1,084,350	$ 8,072,083	$ 12,015,173
To reflect annualized depreciation expenses	2.06		PLT	$ 2,093,093	$ 514,548	$ 3,645,010	$ 6,252,651
To reflect increases in labor and labor-related costs	2.07		LBPLT	$ 183,165	$ 53,069	$ 388,660	$ 624,894
To reflect current interest on construction (CWIP)	2.08		PLT	$ 172,654	$ 42,444	$ 300,669	$ 515,767
To eliminate RRI Domtar Cogen Backup expenses	2.09			$ -	$ (2,086,416)	$ -	$ (2,086,416)
To reflect levelized production expenses	2.10		CP	$ 1,916,312	$ 463,846	$ 3,280,520	$ 5,660,678
To reflect levelized production expenses	2.11		CP	$ 923,161	$ 223,452	$ 1,580,352	$ 2,726,965
To reflect going forward Information Technology support services	2.12		RBPLT	$ 97,453	$ 24,069	$ 170,671	$ 292,194
To reflect amortizaton of rate case expenses	2.13		RBPLT	$ 93,960	$ 23,206	$ 164,553	$ 281,719
To reflect MISO related expenses	2.14		12CPTR	$ 1,667,501	$ 459,102	$ 3,288,398	$ 5,415,000
To annualize interest on long-term debt	2.15		RBPLT	$ 23,483	$ 5,800	$ 41,125	$ 70,408
To reflect leased property income (Soaper Building Rent)	2.16		LBPLT	$ (37,626)	$ (10,902)	$ (79,840)	$ (128,368)
To adjust for costs related to LEM Dispatch	2.17		CP	$ (317,140)	$ (76,764)	$ (542,910)	$ (936,815)
To adjust for costs related to APM	2.18		CP	$ 69,429	$ 16,805	$ 118,855	$ 205,090
To reflect going forward level of Outside Services	2.25		EnergyNS	$ (725,000)	$ (275,000)	$ -	$ (1,000,000)
To eliminate costs for SFPC membership	2.20		RBPLT	$ (60,293)	$ (14,891)	$ (105,591)	$ (180,775)
To adjust for MISO Case-related expenses	2.21		12CPTR	$ (237,459)	$ (65,378)	$ (468,281)	$ (771,118)
To reflect commitment to Energy Efficiency Programs	2.26		EnergyNS	$ 725,000	$ 275,000	$ -	$ 1,000,000
To eliminate promo advertising, lobbying, donation and econ dev	2.23		R01	$ (130,114)	$ (45,872)	$ (331,230)	$ (507,216)
To reflect going forward level of income taxes	2.24		NTPLT	$ 61,251	$ 15,070	$ 106,763	$ 183,084
Total Expense Adjustments				$ (22,066,615)	$ (11,067,360)	$ (70,926,109)	$ (104,060,084)
Total Operating Expenses		TOE		$ 109,847,120	$ 31,263,086	$ 235,408,702	$ 376,518,908
Utility Operating Margins -- Pro-Forma				$ (9,711,995)	$ 2,075,623	$ 33,443,057	$ 25,806,684
Non-Operating Items				$ -	$ -	$ -	-
Total Non-Operating Items				$ -	$ -	$ -	-
Net Utility Operating Margin				$ (9,711,995)	$ 2,075,623	$ 33,443,057	$ 25,806,684
Net Cost Rate Base				$ 390,335,625	$ 96,406,419	$ 683,599,459	$ 1,170,341,502
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				-2.49%	2.15%	4.89%	2.21%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
6 CP - Smelter TIER Adjustment - Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Subsidies Paid and Received at Present Rates							
(subisidies received shown as positive value)							
Rate Base				$ 390,335,625	$ 96,406,419	$ 683,599,459	$ 1,170,341,502
Operating Margins (present rates)				$ (9,711,995)	$ 2,075,623	$ 33,443,057	$ 25,806,684
Operating Margins at Equal Rate of Return	ROR	2.21%		$ 8,607,119	$ 2,125,815	$ 15,073,750	$ 25,806,684
Subsidies Paid and Received				$ 18,319,114	$ 50,193	$ (18,369,307)	$ 0

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT __(SJB-4)

OF

STEPHEN J. BARON

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
12 CP - Smelter TIER Adjustment Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 110,934,700	$ 39,110,620	$ 282,406,135	$ 432,451,455
Off System Sales Revenue			OSSALL	$ 12,699,401	$ 4,615,345	$ 59,229,055	$ 76,543,801
Income from Leased Property Net		OTHREV	RBPLT	$ 45,976	$ 12,696	$ 91,001	$ 149,673
Other Operating Revenue & Income		OTHREV	RBPLT	$ 4,232,544	$ 1,168,737	$ 8,377,465	$ 13,778,745
Total Operating Revenues		TOR		$ 127,912,621	$ 44,907,398	$ 350,103,656	$ 522,923,675
Operating Expenses							
Operation and Maintenance Expenses				$ 117,027,890	$ 39,919,424	$ 289,490,232	$ 446,437,546
Depreciation and Amortization Expenses				$ 10,542,673	$ 2,902,642	$ 20,790,694	$ 34,236,009
Property and Other Taxes			NPT	$ (29,120)	$ (8,017)	$ (57,426)	$ (94,563)
Total Operating Expenses		TOE		$ 127,541,444	$ 42,814,048	$ 310,223,500	$ 480,578,992
Utility Operating Margin				$ 371,177	$ 2,093,350	$ 39,880,156	$ 42,344,683
Non-Operating Items							
Interest Income			RBPLT	$ -	$ -	$ -	$ -
Other Non-Operating Income			RBPLT	$ -	$ -	$ -	$ -
Other Credits			RBPLT	$ -	$ -	$ -	$ -
Interest on Long Term Debt				$ -	$ -	$ -	$ -
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ -	$ -	$ -	$ -
Total Non-Operating Items				$ -	$ -	$ -	$ -
Net Utility Operating Margin		TOM		$ 371,177	$ 2,093,350	$ 39,880,156	$ 42,344,683
Net Cost Rate Base				$ 359,504,551	$ 99,270,357	$ 711,566,594	$ 1,170,341,502

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
12 CP - Smelter TIER Adjustment Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue				$ 127,912,621	$ 44,907,398	$ 350,103,656	$ 522,923,675
Pro-Forma Adjustments:							
To annualize revenue for new industrial customer	2.01			$ -	$ 149,752	$ -	$ 149,752
To adjust mismatch in fuel cost recovery	2.02	FACREV		$ (25,166,503)	$ (9,525,471)	$ (73,123,203)	$ (107,815,177)
To eliminate Environmental Surcharge revenues	2.03	ESREV		$ (5,315,462)	$ (2,025,233)	$ (15,493,538)	$ (22,834,232)
To reflect temperature normalized sales volumes	2.04		EnergyR	$ (421,610)	$ -	$ -	$ (421,610)
To eliminate Non-FAC PPA revenues	2.05	NFPR		$ 2,757,108	$ 1,045,800	$ 7,785,109	$ 11,588,017
To eliminate WKEC Lease Expenses	2.19		RBPLT	$ (45,976)	$ (12,696)	$ (91,001)	$ (149,673)
To eliminate RRI Domtar Cogen Backup revenues	2.09			$ -	$ (1,115,159)	$ -	$ (1,115,159)
To adjust for Smelter TIER Adjustment Charge	2.22			$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 99,720,178	$ 33,424,391	$ 269,181,024	$ 402,325,592

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
12 CP - Smelter TIER Adjustment Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 117,027,890	$ 39,919,424	$ 289,490,232	$ 446,437,546
Depreciation and Amortization Expenses				$ 10,542,673	$ 2,902,642	$ 20,790,694	$ 34,236,009
Property and Other Taxes			NPT	$ (29,120)	$ (8,017)	$ (57,426)	$ (94,563)
Adjustments to Operating Expenses:							
To annualize expenses for new industrial customer	2.01			$ -	$ 110,607	$ -	$ 110,607
To adjust mismatch in fuel cost recovery	2.02		FACREV	$ (25,685,949)	$ (9,722,081)	$ (74,632,493)	$ (110,040,523)
To eliminate Environmental Surcharge expenses	2.03		ESREV	$ (5,462,944)	$ (2,081,425)	$ (15,923,422)	$ (23,467,791)
To reflect weather normalized sales volumes	2.04		EnergyR	$ (295,293)	$ -	$ -	$ (295,293)
To eliminate Non-FAC PPA expenses	2.05		NFPR	$ 2,858,740	$ 1,084,350	$ 8,072,083	$ 12,015,173
To reflect annualized depreciation expenses	2.06		PLT	$ 1,925,448	$ 530,120	$ 3,797,082	$ 6,252,651
To reflect increases in labor and labor-related costs	2.07		LBPLT	$ 174,259	$ 53,897	$ 396,739	$ 624,894
To reflect current interest on construction (CWIP)	2.08		PLT	$ 158,826	$ 43,728	$ 313,213	$ 515,767
To eliminate RRI Domtar Cogen Backup expenses	2.09			$ -	$ (2,086,416)	$ -	$ (2,086,416)
To reflect levelized production expenses	2.10		CP	$ 1,743,155	$ 479,931	$ 3,437,592	$ 5,660,678
To reflect levelized production expenses	2.11		CP	$ 839,745	$ 231,201	$ 1,656,019	$ 2,726,965
To reflect going forward Information Technology support services	2.12		RBPLT	$ 89,756	$ 24,784	$ 177,654	$ 292,194
To reflect amortizaton of rate case expenses	2.13		RBPLT	$ 86,538	$ 23,896	$ 171,285	$ 281,719
To reflect MISO related expenses	2.14		12CPTR	$ 1,667,501	$ 459,102	$ 3,288,398	$ 5,415,000
To annualize interest on long-term debt	2.15		RBPLT	$ 21,628	$ 5,972	$ 42,808	$ 70,408
To reflect leased property income (Soaper Building Rent)	2.16		LBPLT	$ (35,797)	$ (11,072)	$ (81,500)	$ (128,368)
To adjust for costs related to LEM Dispatch	2.17		CP	$ (288,484)	$ (79,426)	$ (568,905)	$ (936,815)
To adjust for costs related to APM	2.18		CP	$ 63,156	$ 17,388	$ 124,546	$ 205,090
To reflect going forward level of Outside Services	2.25		EnergyNS	$ (725,000)	$ (275,000)	$ -	$ (1,000,000)
To eliminate costs for SFPC membership	2.20		RBPLT	$ (55,530)	$ (15,334)	$ (109,911)	$ (180,775)
To adjust for MISO Case-related expenses	2.21		12CPTR	$ (237,459)	$ (65,378)	$ (468,281)	$ (771,118)
To reflect commitment to Energy Efficiency Programs	2.26		EnergyNS	$ 725,000	$ 275,000	$ -	$ 1,000,000
To eliminate promo advertising, lobbying, donation and econ dev	2.23		R01	$ (130,114)	$ (45,872)	$ (331,230)	$ (507,216)
To reflect going forward level of income taxes	2.24		NTPLT	$ 56,379	$ 15,522	$ 111,182	$ 183,084
Total Expense Adjustments				$ (22,506,439)	$ (11,026,504)	$ (70,527,141)	$ (104,060,084)
Total Operating Expenses		TOE		$ 105,035,005	$ 31,787,544	$ 239,696,360	$ 376,518,908
Utility Operating Margins -- Pro-Forma				$ (5,314,827)	$ 1,636,847	$ 29,484,664	$ 25,806,684
Non-Operating Items				$ -	$ -	$ -	$ -
Total Non-Operating Items				$ -	$ -	$ -	$ -
Net Utility Operating Margin				$ (5,314,827)	$ 1,636,847	$ 29,484,664	$ 25,806,684
Net Cost Rate Base				$ 359,504,551	$ 99,270,357	$ 711,566,594	$ 1,170,341,502
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				-1.48%	1.65%	4.14%	2.21%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
12 CP - Smelter TIER Adjustment Revenues @ $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Subsidies Paid and Received at Present Rates							
(subisidies received shown as positive value)							
Rate Base				$ 359,504,551	$ 99,270,357	$ 711,566,594	$ 1,170,341,502
Operating Margins (present rates)				$ (5,314,827)	$ 1,636,847	$ 29,484,664	$ 25,806,684
Operating Margins at Equal Rate of Return	ROR	2.21%		$ 7,927,276	$ 2,188,967	$ 15,690,441	$ 25,806,684
Subsidies Paid and Received				$ 13,242,103	$ 552,120	$ (13,794,223)	$ 0

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	**CASE NO. 2011-00036**
GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
Average Excess Demand - Smelter TIER Adjustment Revenues at $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 110,934,700	$ 39,110,620	$ 282,406,135	$ 432,451,455
Off System Sales Revenue			OSSALL	$ 12,744,879	$ 4,569,868	$ 59,229,055	$ 76,543,801
Income from Leased Property Net		OTHREV	RBPLT	$ 51,608	$ 12,924	$ 85,141	$ 149,673
Other Operating Revenue & Income		OTHREV	RBPLT	$ 4,750,980	$ 1,189,792	$ 7,837,973	$ 13,778,745
Total Operating Revenues		TOR		$ 128,482,167	$ 44,883,204	$ 349,558,304	$ 522,923,675
Operating Expenses							
Operation and Maintenance Expenses				$ 121,960,887	$ 40,042,146	$ 284,434,513	$ 446,437,546
Depreciation and Amortization Expenses				$ 11,810,735	$ 2,954,142	$ 19,471,132	$ 34,236,009
Property and Other Taxes			NPT	$ (32,733)	$ (8,164)	$ (53,666)	$ (94,563)
Total Operating Expenses		TOE		$ 133,738,889	$ 42,988,124	$ 303,851,979	$ 480,578,992
Utility Operating Margin				$ (5,256,723)	$ 1,895,081	$ 45,706,325	$ 42,344,683
Non-Operating Items							
Interest Income			RBPLT	$ -	$ -	$ -	$ -
Other Non-Operating Income			RBPLT	$ -	$ -	$ -	$ -
Other Credits			RBPLT	$ -	$ -	$ -	$ -
Interest on Long Term Debt				$ -	$ -	$ -	$ -
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ -	$ -	$ -	$ -
Total Non-Operating Items				$ -	$ -	$ -	$ -
Net Utility Operating Margin		TOM		$ (5,256,723)	$ 1,895,081	$ 45,706,325	$ 42,344,683
Net Cost Rate Base				$ 403,539,604	$ 101,058,766	$ 665,743,132	$ 1,170,341,502

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
Average Excess Demand - Smelter TIER Adjustment Revenues at $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue				$ 128,482,167	$ 44,883,204	$ 349,558,304	$ 522,923,675
Pro-Forma Adjustments:							
To annualize revenue for new industrial customer	2.01			$ -	$ 149,752	$ -	$ 149,752
To adjust mismatch in fuel cost recovery	2.02	FACREV		$ (25,166,503)	$ (9,525,471)	$ (73,123,203)	$ (107,815,177)
To eliminate Environmental Surcharge revenues	2.03	ESREV		$ (5,315,462)	$ (2,025,233)	$ (15,493,538)	$ (22,834,232)
To reflect temperature normalized sales volumes	2.04		EnergyR	$ (421,610)	$ -	$ -	$ (421,610)
To eliminate Non-FAC PPA revenues	2.05	NFPR		$ 2,757,108	$ 1,045,800	$ 7,785,109	$ 11,588,017
To eliminate WKEC Lease Expenses	2.19		RBPLT	$ (51,608)	$ (12,924)	$ (85,141)	$ (149,673)
To eliminate RRI Domtar Cogen Backup revenues	2.09			$ -	$ (1,115,159)	$ -	$ (1,115,159)
To adjust for Smelter TIER Adjustment Charge	2.22			$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 100,284,092	$ 33,399,969	$ 268,641,532	$ 402,325,592

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
Average Excess Demand - Smelter TIER Adjustment Revenues at $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 121,960,887	$ 40,042,146	$ 284,434,513	$ 446,437,546
Depreciation and Amortization Expenses				$ 11,810,735	$ 2,954,142	$ 19,471,132	$ 34,236,009
Property and Other Taxes			NPT	$ (32,733)	$ (8,164)	$ (53,666)	$ (94,563)
Adjustments to Operating Expenses:							
To annualize expenses for new industrial customer	2.01			$ -	$ 110,607	$ -	$ 110,607
To adjust mismatch in fuel cost recovery	2.02		FACREV	$ (25,685,949)	$ (9,722,081)	$ (74,632,493)	$ (110,040,523)
To eliminate Environmental Surcharge expenses	2.03		ESREV	$ (5,462,944)	$ (2,081,425)	$ (15,923,422)	$ (23,467,791)
To reflect weather normalized sales volumes	2.04		EnergyR	$ (295,293)	$ -	$ -	$ (295,293)
To eliminate Non-FAC PPA expenses	2.05		NFPR	$ 2,858,740	$ 1,084,350	$ 8,072,083	$ 12,015,173
To reflect annualized depreciation expenses	2.06		PLT	$ 2,164,890	$ 539,845	$ 3,547,916	$ 6,252,651
To reflect increases in labor and labor-related costs	2.07		LBPLT	$ 186,980	$ 54,413	$ 383,501	$ 624,894
To reflect current interest on construction (CWIP)	2.08		PLT	$ 178,577	$ 44,531	$ 292,659	$ 515,767
To eliminate RRI Domtar Cogen Backup expenses	2.09			$ -	$ (2,086,416)	$ -	$ (2,086,416)
To reflect levelized production expenses	2.10		CP	$ 1,990,470	$ 489,975	$ 3,180,233	$ 5,660,678
To reflect levelized production expenses	2.11		CP	$ 958,885	$ 236,040	$ 1,532,040	$ 2,726,965
To reflect going forward Information Technology support services	2.12		RBPLT	$ 100,750	$ 25,231	$ 166,213	$ 292,194
To reflect amortizaton of rate case expenses	2.13		RBPLT	$ 97,138	$ 24,326	$ 160,254	$ 281,719
To reflect MISO related expenses	2.14		12CPTR	$ 1,667,501	$ 459,102	$ 3,288,398	$ 5,415,000
To annualize interest on long-term debt	2.15		RBPLT	$ 24,277	$ 6,080	$ 40,051	$ 70,408
To reflect leased property income (Soaper Building Rent)	2.16		LBPLT	$ (38,410)	$ (11,178)	$ (78,780)	$ (128,368)
To adjust for costs related to LEM Dispatch	2.17		CP	$ (329,413)	$ (81,089)	$ (526,313)	$ (936,815)
To adjust for costs related to APM	2.18		CP	$ 72,116	$ 17,752	$ 115,222	$ 205,090
To reflect going forward level of Outside Services	2.25		EnergyNS	$ (725,000)	$ (275,000)	$ -	$ (1,000,000)
To eliminate costs for SFPC membership	2.20		RBPLT	$ (62,332)	$ (15,610)	$ (102,833)	$ (180,775)
To adjust for MISO Case-related expenses	2.21		12CPTR	$ (237,459)	$ (65,378)	$ (468,281)	$ (771,118)
To reflect commitment to Energy Efficiency Programs	2.26		EnergyNS	$ 725,000	$ 275,000	$ -	$ 1,000,000
To eliminate promo advertising, lobbying, donation and econ dev	2.23		R01	$ (130,114)	$ (45,872)	$ (331,230)	$ (507,216)
To reflect going forward level of income taxes	2.24		NTPLT	$ 63,337	$ 15,805	$ 103,942	$ 183,084
Total Expense Adjustments				$ (21,878,252)	$ (11,000,991)	$ (71,180,840)	$ (104,060,084)
Total Operating Expenses		TOE		$ 111,860,637	$ 31,987,132	$ 232,671,139	$ 376,518,908
Utility Operating Margins -- Pro-Forma				$ (11,576,545)	$ 1,412,836	$ 35,970,393	$ 25,806,684
Non-Operating Items				$ -	$ -	$ -	$ -
Total Non-Operating Items				$ -	$ -	$ -	$ -
Net Utility Operating Margin				$ (11,576,545)	$ 1,412,836	$ 35,970,393	$ 25,806,684
Net Cost Rate Base				$ 403,539,604	$ 101,058,766	$ 665,743,132	$ 1,170,341,502
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				-2.87%	1.40%	5.40%	2.21%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation
12 Months Ended
October 2010
Average Excess Demand - Smelter TIER Adjustment Revenues at $1.95/mWh

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelters	Total System
Subsidies Paid and Received at Present Rates							
(subisidies received shown as positive value)							
Rate Base				$ 403,539,604	$ 101,058,766	$ 665,743,132	$ 1,170,341,502
Operating Margins (present rates)				$ (11,576,545)	$ 1,412,836	$ 35,970,393	$ 25,806,684
Operating Margins at Equal Rate of Return	ROR	2.21%		$ 8,898,274	$ 2,228,402	$ 14,680,008	$ 25,806,684
Subsidies Paid and Received				$ 20,474,819	$ 815,566	$ (21,290,385)	$ (0)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	**CASE NO. 2011-00036**
GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

Big Rivers Electric Corporation
KIUC Proposed Rate Increases
6 CP Cost of Service using Seelye model with TIER Adjustment at test year level of $1.95

Line		Total System	Rurals	Large Industrials	Smelters
1	Rate Base - 6 CP	1,170,341,502	390,335,625	96,406,419	683,599,459
2	Net Utility Operating Margin	25,806,684	(9,711,995)	2,075,623	33,443,057
3	Return on Rate Base	2.21%	-2.49%	2.15%	4.89%
4	Subsidy at Present Rates	-	(18,319,114)	(50,193)	18,369,307
5	**KIUC Proposed Revenue Increase**	**18,679,000**			
6	Eliminate Subsidy to Rurals	18,319,114	18,319,114	-	-
7	Remainder of Increase to be Allocated	359,886			
8	Demand/Energy Base Revenue - Current Rates	118,930,921	88,490,963	30,439,958	
9	Weather Normalization Adjustment	(421,610)	(421,610)	-	
10	Base Rate Revenue	322,119,734	88,069,353	30,439,958	203,610,423
11	Revenue Allocator using Smelter/Industrial Ratio	322,119,734	88,069,353	30,439,958	203,610,423
12	**Percent Allocator**	**100.00%**	**27.34%**	**9.45%**	**63.21%**
13	Spread of Increase Remainder	359,886	98,395	34,009	227,482
14	Step 1 Increase - Rurals Subsidy	18,319,114	18,319,114	-	-
15	Net Increase (before Rural Reserve or Capital Credits)	18,679,000	18,417,509	34,009	227,482
16	Rural Mitigation from Rural Economic Reserve Fund	(4,245,506)	(4,245,506)	-	-
17	Net Increase after Mitigation		14,172,003	34,009	227,482
18	Patronage Capital Distribution per kWh	(2,708,000)	(621,285)	(235,635)	(1,851,080)
19	Final Effective Base Rate Increase		13,550,718	(201,626)	(1,623,598)
20	Present Revenue	432,165,302	110,513,089	39,260,372	282,391,841
21	Percent Increase		12.26%	-0.51%	-0.57%
22	Amortization of Non-FAC PPA	(3,236,077)	(2,340,068)	(896,009)	-
23	Revenue Increase with Non-FAC PPA Amortization		11,210,650	(1,097,635)	(1,623,598)
24	Percent Increase		10.14%	-2.80%	-0.57%
25	Impact of Lowering the Non-FAC PPA Base	(2,959,158)	(2,145,453)	(813,705)	-
26	Adjusted Revenue Increase		9,065,197	(1,911,340)	(1,623,598)
27	Percent Increase		8.20%	-4.87%	-0.57%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 1) *With regard to Mr. Blackburn's testimony on energy efficiency on pages 32 to 35, please provide the following:*

a. For each project budgeted in 2011 (per testimony page 33 at line 5), please provide a detailed description of the project, a table showing monthly tasks, capital expenditures and expenses in 2011.
b. For each project budgeted in 2012 (per testimony page 33 at line 6), please provide a detailed description of the project, a table showing monthly tasks, capital expenditures and expenses in 2012.

Response) a. and b. Big Rivers has budgeted amounts for energy efficiency and DSM programs for 2011 and 2012, but cannot provide detailed descriptions, monthly tasks, capital expenditures or expenses as requested since these programs are still in the early stages of development, with short-term pilot programs either underway or in the planning phase. Based on the outcomes of the pilot programs, Big Rivers will develop individual work plans and budgets for the energy efficiency and DSM programs to be implemented. The descriptions of the pilot programs are as follows:

<u>Clothes Washer Replacement Rebate Pilot</u>
The purpose of the pilot is to test promotional mediums for communicating the incentive to members and the effectiveness of the incentive amount. The member will be required to provide proof of purchase and installation at the service address. The member will also be required to fill out a survey to determine the energy source for the dryer and where the member heard about the program.

HVAC & Refrigeration Tune-Up

The purpose of this pilot is to test the effectiveness of cash incentive payments to motivate members to initiate maintenance for their air conditioning equipment. The member will also be required to fill out a survey to determine the length of time since the previous maintenance call for each unit and where the member heard about the program.

Home Weatherization Pilot

The purpose of this pilot is to determine the benefit, cost and procedures for weatherizing homes. Hoosier Energy has deemed its weatherization program a success, and Jackson Purchase Energy and Big Rivers will work with the weatherization contractor utilized as part of the Hoosier Energy program in an effort to replicate the success in Western Kentucky. Big Rivers' and its members' staffs will use their combined knowledge of residential energy efficiency to develop the list of measures and the process which will result in the maximum benefit at the lowest cost. This program will also involve integrating the Kentucky Home Performance Program into the administrative process.

Energy STAR New Home Program

The purpose of the pilot is to test communication of the incentive to the members and the effectiveness of the incentive amount. The Energy STAR new-home construction standard is an objective, reliable and verifiable energy efficiency program that ensures the member will see substantial savings from the new home.

The Energy STAR-certified contractor will complete a whole-house analysis, ensuring that quality work is performed and energy efficiency criteria are met. This evaluator works closely with the builder to determine the needed energy-saving equipment, construction techniques and required on-site diagnostic testing/inspections are documented in order to assure that the home is eligible to earn the Energy STAR certification. The home must meet the guidelines, making it at least 15-30% more efficient than standard homes.

Refrigerator Replacement Rebate Pilot

The purpose of the pilot is to test communication of the incentive to the members and the effectiveness of the incentive amount. The member will be required to provide proof of purchase of the new refrigerator and haul-away and recycling of the old unit. The member will also be required to fill out a survey to determine the condition of the old refrigerator and where the member heard about the program.

Commercial High Efficiency Lighting Replacement Rebate Pilot

The purpose of the pilot is to determine incentive levels necessary to motivate members to upgrade, as well as to test methods of promoting high efficiency commercial lighting to retail commercial members and establish methods of design and installation that allow the use of local contractors. A process of verification will be established during this pilot.

LED/Induction Outdoor Lighting Evaluation Pilot Plan

The purpose of this pilot is to test the light quality and quantity, energy consumption and product durability of both Light Emitting Diode ("LED") and Induction lamps as potential replacements for the Mercury Vapor and Metal Halide lamp. The LED and Induction lamps have significantly higher costs, but have significantly longer lives and provide higher energy efficiency.

Energy efficiency and DSM programs that are determined to be cost effective based on the pilot programs will be implemented throughout the last half of 2011, after program design is complete. Each of Big Rivers' Member Cooperatives is committed to providing a wide range of DSM programs, as described in the DSM Potential Report (Appendix B to Big Rivers' 2010 Integrated Resource Plan, as filed on November 15, 2010 in KPSC Case No. 2010-00443.). The DSM Potential Report recommends that the following programs be evaluated for implementation should they prove cost effective:

- Residential Lighting
- Residential Efficient Appliances
- Residential Advanced Technologies
- Residential Weatherization
- Residential New Construction
- Commercial and Industrial Lighting
- Commercial and Industrial Heating Ventilation and Air Conditioning

Witness) C. William Blackburn

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	CASE NO. 2011-00036
GENERAL ADJUSTMENT IN RATES	)	

EXHIBIT__(SJB-8)

OF

STEPHEN J. BARON

BIG RIVERS ELECTRIC CORPORATION

**APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2011-00036**

Response to the Kentucky Industrial Utility Customers' Second Request for Information dated April 28, 2011

May 11, 2011

Item 3) ***Please provide an explanation for Big Rivers' decision (testimony page 33 at lines 13 to 14) not to seek the establishment of a mechanism in this case to recover energy efficiency costs as they are incurred.***

Response) Although KRS 278.285 permits utilities to implement demand-side management ("DSM") cost recovery mechanisms to recover the costs of demand-side management programs, the statute does not require that the costs of energy efficiency programs be recovered through a DSM cost recovery mechanism. Thus, there is no statutory requirement that would prohibit utilities from recovering energy efficiency costs through base rates.

Recovering the proposed energy efficiency costs through base rates will avoid the implementation of another cost recovery mechanism by Big Rivers and would thus avoid the need for Big Rivers' rural member systems to develop DSM recovery mechanisms of their own to flow through costs from a Big Rivers DSM cost recovery mechanism.

Although Big Rivers' preference would be to recover its proposed energy efficiency expenses through base rates, Big Rivers does not have a strong objection to recovering these costs through a DSM cost recovery mechanism, provided that such a mechanism is implemented concurrently with the base rates approved by the Commission in this rate case proceeding.

Witnesses) William Steven Seelye and C. William Blackburn

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	CASE NO. 2011-00036

EXHIBIT__(SJB-9)

OF

STEPHEN J. BARON

RATES, TERMS AND CONDITIONS – SECTION 1

STANDARD RATE – LICX – Large Industrial Customer Expansion [T]

Applicability:

This schedule shall be applicable as follows:

To purchases made by a Member Cooperative for service to any New Customer initiating service ~~after August 31, 1999~~, including New Customers with a QF as defined in Rate Schedule QFP and QFS, that either initially contracts for five (5) MWs or more of capacity or whose aggregate peak load at any time amounts to five (5) MWs or greater (including any later increases to such load) in which case the entire load shall be thereafter subject to this rate schedule. [T]

~~To purchases made by a Member Cooperative for expanded load requirements of Existing Customers, including Existing Customers with a QF as defined in Rate Schedules QFP and QFS, where: (i) the customer was in existence and served under the then effective Big Rivers Large Industrial Customer Rate Schedule any time during the Base Year and, (ii) the expanded load requirements are increases in peak load which in the aggregate result in a peak demand which is at least five (5) MWs greater than the customer's Base Year peak demand.~~ [T]

~~To purchases made by a Member Cooperative for the expanded load requirements of Existing Customers, including Existing Customers with a QF as defined in Rate Schedules QFP and QFS, where: (i) the customer's load was in existence and served through a Rural Delivery Point as defined in Rate Schedule RDS, (ii) the expanded load requirements are increases in peak load which in aggregate result in a peak demand which is at least five (5) MWs greater than the customer's Base Year peak demand; and (iii) the customer requires service through a dedicated delivery point as defined in Rate Schedule LIC.~~ [T] [T] [T]

Availability:

This schedule is available to any of the Member Cooperatives of Big Rivers for service to certain large industrial or commercial loads as specified in item (a) defining applicability. For all loads meeting the applicability criteria below, no other Big Rivers' tariff rate will be available. As an alternative to this rate schedule, the Member Cooperative may negotiate a "Special Contract Rate" with Big Rivers for application on a case by case basis for loads meeting the applicability criteria above.

For All Territory Served By
Cooperative's Transmission System
P.S.C.KY.NO. 24

Original SHEET NO. 30

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C.KY.NO. 23

Original SHEET NO. 53

RATES, TERMS AND CONDITIONS - SECTION 1

STANDARD RATE – LICX – Large Industrial Customer Expansion contd [T]

Conditions of Service:

To receive service hereunder, the Member Cooperative must:

Obtain from the customer an executed written contract ~~or amend an existing contract~~, for electric service [T] hereunder with terms acceptable to Big Rivers.

Enter into a contract with Big Rivers~~, or amend an existing contract with Big Rivers,~~ to specify the terms [T] and conditions of service between Big Rivers and the Member Cooperative regarding power supply for the customer.

Definitions: [T]

Please see Section 4 for definition common to all tariffs.

~~Base Year – "Base Year" shall mean the twelve (12) calendar months from September 1998 through August 1999.~~ [T]

~~Existing Customer – "Existing Customer" shall mean any customer of a Member Cooperative served as of August 31, 1999.~~ [T]

New Customer – "New Customer" shall mean any customer of a Member Cooperative commencing [T] service on or after September 1, ~~1999~~ 2011.

Special Contract Rate – "Special Contract Rate" shall mean a rate negotiated with a Distribution [T] Cooperative to serve the load requirements of a New Customer ~~or an Existing Customer,~~ which will include, upon request by the Distribution Cooperative, rates based on Real Time Pricing.

DATE OF ISSUE March 1, 2011 DATE EFFECTIVE April 1, 2011

ISSUED BY Mark A. Bailey President and Chief Executive Officer
Big Rivers Electric Corporation 201 3rd St., Henderson, KY 42420

For All Territory Served By
Cooperative's Transmission System
P.S.C.KY.NO. 24

Original SHEET NO. 31

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C.KY.NO. 23

Original SHEET NO. 55

STANDARD RATE – LICX – Large Industrial Customer Expansion contd [T]

Expansion Demand and Expansion Energy: [T]

Expansion Demand and Expansion Energy for the load requirements of a New Customer shall be the Member Cooperative's total demand and energy requirements for the New Customer, including amounts sufficient to compensate for losses on the Big Rivers' transmission system as set forth in the OATT. [T]

~~Expansion Demand for the expanded local requirements of an Existing Customer shall be the amount in kW by which the customer's Billing Demand exceeds the customer's Base Year peak demand, plus an additional amount of demand sufficient to compensate for losses on the Big Rivers' transmission system as set forth in the OATT. In those months in which there is Expansion Demand, Expansion Energy shall be the amount in kWh by which the customer's kWh usage for the current month exceeds the customer's actual kWh usage for the corresponding month of the Base Year, plus an additional amount of kWh sufficient to compensate for losses on the Big Rivers' transmission system as set forth in the OATT.~~ [T] [T] [T]

Rates and Charges: [T]

Expansion rate and charges shall be the sum of the following, including but not limited to Real-Time pricing:

(1) Expansion Demand and Expansion Energy Rates:
The Expansion Demand rates, Expansion Energy rates, or both shall be established to correspond to the actual costs of power purchased by Big Rivers from Third-Party Suppliers selected by Big Rivers from which Big Rivers procures the supply and delivery of the type and quantity of service required by the Member Cooperative for resale to its customer. Such monthly costs shall include the sum of all Third-Party Supplier charges, including capacity and energy charges, charges to compensate for transmission losses on Third-Party transmission systems, and all transmission and ancillary services charges on Third-Party transmission systems paid by Big Rivers to purchase such Expansion Demand and Expansion Energy and have it delivered to Big Rivers' transmission system.

DATE OF ISSUE March 1, 2011 DATE EFFECTIVE April 1, 2011

ISSUED BY Mark A. Bailey President and Chief Executive Officer
Big Rivers Electric Corporation, 201 3rd St., Henderson, KY 42420

STANDARD RATE – LICX – Large Industrial Customer Expansion contd [T]

(2) **Expansion Demand Transmission Rate:**
Big Rivers shall assess unbundled charges for network transmission service on the Big Rivers' Transmission System according to the rates in the OATT applied to each kW taken as Expansion Demand. [T]

(3) **Ancillary Services Rates for Expansion Demand and Expansion Energy:**
Big Rivers shall assess unbundled rates for all ancillary services required to serve load served under this rate schedule. Big Rivers shall supply the following six ancillary services as defined and set forth in the OATT: (1) Scheduling System Control and Dispatch; (2) Reactive Supply and Voltage Control from Generation Sources Services; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve – Spinning Reserve Service; and (6) Operating Reserve – Supplemental Reserve Service. [T]

(4) **Big Rivers Adder:**
In addition to the charges described above, Big Rivers shall charge $0.38 per kW/month for each kW billed to the Member Cooperative under this tariff for resale by the Member Cooperative to the qualifying customer. [T]

Meters:
Big Rivers shall provide an appropriate meter to all customers served under this rate schedule. [T]

STANDARD RATE – LICX – Large Industrial Customer Expansion
Billing Form [T]

INVOICE
BIG RIVERS ELECTRIC CORP. P. O. BOX 24 HENDERSON, KY 42419-0024
MONTH ENDING mm/dd/yy

TO: LARGE INDUSTRIAL CUSTOMER EXPANSION
DELIVERY POINTS

ACCOUNT
SERVICE FROM mm/dd/yy THRU mm/dd/yy
USAGE:

USAGE	DEMAND	TIME	DAY	METER	MULT	KW DEMAND
		00:00 A (or P)	mm/dd		1000	00,000

POWER FACTOR	BASE	PEAK	AVERAGE		KW DEMAND BILLED
EXPANSION DEMAND	00.00%	00.00%	00.00%		000,000

ENERGY	PREVIOUS	PRESENT	DIFFERENCE	MULT.	KWH USED
EXPANSION ENERGY	00000.000	00000.000	0000.000	1000	00,000,000

EXPANSION DEMAND & EXPANSION ENERGY						
EXPANSION DEMAND, INCLUDING LOSSESS		kW	TIMES	$	EQUALS	$
P/F PENALTY		kW	TIMES	$	EQUALS	$
EXPANSION ENERGY, INCLUDING LOSSESS		kWh	TIMES	$	EQUALS	$
OTHER EXPANSION SERVICE CHARGES					EQUALS	$
SUBTOTAL						$
EXPANSION DEMAND TRANSMISSION						
LOAD RATIO SHARE OF NETWORK LOAD						$
EXPANSION DEMAND & EXPANSION ENERGY ANCILLIARY SERVICES						
SCHEDULING SYSTEM CONTROL & DISPATCH SERVICE						$
REACTIVE SUPPLY & VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE						$
REGULATION & FREQUENCY RESPONSIVE SERVICE						$
ENERGY IMBALANCE SERVICE						$
OPERATING RESERVE – SPINNING RESERVE SERVICE						$
OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE						$
SUBTOTAL						$
BIG RIVERS ADDER						
EXPANSION DEMAND		kW	TIMES	$	EQUALS	$
FUEL ADJUSTMENT CLAUSE	0,000,000	kWh	AT	$0.0000000	EQUALS	$
ENVIRONMENTAL SURCHARGE	0,000,000	kWh	AT	$0.0000000	EQUALS	$
UNWIND SURCREDIT	0,000,000	kWh	AT	$0.0000000	EQUALS	$
MEMBER RATE STABILITY MECHANISM						$
CSR						$
RRES	0,000,000	kWh	AT	$0.0000000	EQUALS	$
REBATE ADJUSTMENT						$
NSNFP	0,000,000	kWh	AT	$0.0000000	EQUALS	$
					TOTAL AMOUNT DUE	$

[T]

LOAD FACTOR

ACTUAL	BILLED	MILLS PER KWH
00.00%	00.00%	00.00

DUE IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE THE FIRST WORKING DAY AFTER THE 24TH OF THE MONTH

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

Sworn to and subscribed before me on this
23rd day of May 2011.

Notary Public

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