ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

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**

VOLUME 3 OF 3

DIRECT TESTIMONY
[Application Exhibits 48 through 57]

AND

ADDITIONAL APPLICATION EXHIBITS 58 THROUGH 59

FILED: **March 1, 2011**

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

DIRECT TESTIMONY

OF

MARK A. BAILEY
PRESIDENT & CHIEF EXECUTIVE OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
MARK A. BAILEY

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DIRECT TESTIMONY
OF
MARK A. BAILEY

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Mark A. Bailey. I am employed by Big Rivers Electric Corporation ("Big Rivers") at 201 Third Street, Henderson Kentucky, 42420 as its President and Chief Executive Officer. I have held this position since October 2008. Previously, I was employed by Kenergy Corp. as its President and CEO for two years and prior to that by American Electric Power Company ("AEP") for nearly 30 years, beginning as an electrical engineer in 1974. A copy of my resume is attached as Exhibit Bailey-1 to my testimony.

Q. Have you previously testified before this Commission?

A. Yes. I have testified on behalf of Big Rivers previously. I testified in Case No. 2009-00040 and also in Case No. 2007-00455 (the "Unwind Proceeding"), in which Big Rivers and E.ON U.S. LLC sought and obtained the Commission's approval to unwind their 1998 lease transaction (the "Unwind Transaction"). Most recently I sponsored testimony and responses to discovery in Case No. 2010-00043, *In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of Its Transmission System to Midwest Independent Transmission System Operator, Inc.* In addition, I have testified before state regulatory commissions in Arkansas, Texas, Louisiana, and Oklahoma.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Big Rivers' need for the rate relief requested in this proceeding. My testimony begins by introducing the witnesses who will testify on behalf of Big Rivers, with a brief description of the topics that each witness will address. I also provide a summary of the reasons that Big Rivers is filing this request for rate relief. Finally, I provide a summary of Big Rivers' proposed rate requests, including changes to the rates, terms and conditions in the existing Big Rivers tariffs and several proposed new rate mechanisms and corresponding tariffs.

Q. Please summarize your testimony.

A. Simply put, the current rates for Big Rivers do not provide sufficient revenues for Big Rivers to meet its financial obligations. For the twelve months ended October 31, 2010, on an adjusted basis, Big Rivers has a revenue deficiency of $39,952,927. Big Rivers is proposing to increase its base rates in order to eliminate this revenue deficiency.

Big Rivers needs to increase its base rates in order to meet the financial requirements set forth in its debt agreements. Specifically, this increase in base rates is necessary so that Big Rivers can meet its Margins for Interest Ratio ("MFIR") requirement and maintain investment grade credit ratings, as required by its debt covenants.

Big Rivers also must maintain its generating assets in a prudent manner to ensure the continued reliable operation of these facilities in the future. Due to economic conditions, Big Rivers reduced expenses and deferred maintenance on certain generation assets in the test year in order to achieve sufficient net margins to meet its loan covenants. The costs associated with planned unit outages and other planned maintenance activities in the test year are not representative of the costs for production outages on a prospective basis.

In order to meet its NERC Contingency Reserve obligations, Big Rivers became a transmission-owning member of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") effective December 1, 2010. Membership in the Midwest ISO increases Big Rivers' costs, which further supports the need for rate relief.

Finally, Big Rivers proposes several other changes to its rates, terms and conditions to maintain its service to its Members and to better manage some of the requirements established pursuant to the Commission's March 6, 2009 Order in the Unwind Proceeding ("Unwind Order"). These include modifications to the Member Rate Stability Mechanism ("MRSM"), Rural Economic Reserve ("RER"), Non-FAC PPA Regulatory Account, and Non-FAC PPA base purchased power cost. These are described further in my testimony and in the direct testimony of other witnesses listed below.

III. INTRODUCTION OF WITNESSES AND THEIR TESTIMONY

Q. Please identify the witnesses that will testify for Big Rivers and the areas which their testimony will address.

A. In addition to my testimony, Big Rivers presents the testimony of nine witnesses:

1) C. William Blackburn (Exhibit 49). Mr. Blackburn, Big Rivers' Senior Vice President Financial & Energy Services and Chief Financial Officer, provides a detailed description of Big Rivers' financial obligations. He also describes the status of each of the requirements or commitments applicable to Big Rivers ("Unwind Commitments") pursuant to the Unwind Order. Mr. Blackburn provides a benchmark comparison and history of Big Rivers' rates. He also summarizes the service agreements in place between Big Rivers and two large aluminum smelters, Century Aluminum of Kentucky General Partnership ("Century") and Alcan Primary Products Corporation ("Alcan") (collectively, the "Smelters") and discusses Big Rivers' plans for managing the risk of one or both Smelters terminating their respective service agreements.

2) **Alan Spen** (Exhibit 50), Senior Director at Public Financial Management, Inc., provides insight into the credit ratings process as it applies to Big Rivers. First, Mr. Spen summarizes current rating agency criteria for generation and transmission ("G&T") cooperatives and presents his independent view of Big Rivers' strengths and weaknesses from the standpoint of the ratings process. Next, Mr. Spen furnishes a list of current credit ratings for the G&T cooperative sector and describes Big Rivers' standing in that group. Finally, Mr. Spen provides an independent opinion on how the credit markets would view Big Rivers' credit if the Commission grants the rate relief requested in this proceeding.

3) **John Wolfram** (Exhibit 51). Mr. Wolfram, Senior Consultant with The Prime Group, LLC, summarizes the revenue requirements analysis for Big Rivers for the test year ended October 2010, lists all of the proposed pro forma adjustments to test year revenues and expenses to account for known and measurable changes, and supports several of the proposed pro forma adjustments.

4) **Robert W. Berry** (Exhibit 52). Mr. Berry, Big Rivers' Vice President, Production, describes Big Rivers' generating system and the performance of the generating units, and explains why it is absolutely essential that Big Rivers' rates provide for the inclusion of a prudent level of plant maintenance costs. The level of

maintenance costs in the test year is inadequate on a going-forward basis, and without the additional revenue requirement associated with the pro forma adjustment, Big Rivers will be required to reduce planned expenditures in order to meet its MFIR and maintain credit ratings as required in its long-term debt agreements. If it is not granted an adequate revenue increase in this proceeding, the only option available to Big Rivers to meet its MFIR requirements would be to reduce expenditures including plant maintenance, which would have an adverse impact on generating unit reliability.

5) **David G. Crockett** (Exhibit 53). Mr. Crockett, Big Rivers' Vice President, System Operations, describes Big Rivers' experience to date with its status as a transmission-owning member of the Midwest ISO. Mr. Crockett also provides information regarding potential Midwest ISO cost projections and describes the status of the Phase 2 Transmission Projects that Big Rivers committed to complete pursuant to Appendix A Item 22 of the Unwind Order.

6) **Ted J. Kelly** (Exhibit 54). Mr. Kelly, a Principal at the firm of Burns & McDonnell, sponsors the Burns & McDonnell Report on the Comprehensive Depreciation Rate Study prepared for Big Rivers in order to comply with the Unwind Order, which required Big Rivers to conduct a new depreciation rate study as part of Big Rivers' submission in connection with its filing for a general review of its operations and tariffs.

7) **Mark A. Hite** (Exhibit 55). Mr. Hite, Big Rivers' Vice President of Accounting, presents the financial statements and records of Big Rivers, supports certain accounting activities required by the Unwind Order, and supports numerous pro

forma adjustments to Big Rivers' twelve-month historical test period revenues and expenses for known and measurable changes.

8) **Albert M. Yockey** (Exhibit 56). Mr. Yockey, Big Rivers' Vice President, Governmental Relations and Enterprise Risk Management, introduces the changes proposed by Big Rivers to its current tariff on file with this Commission. Mr. Yockey also provides a review of a number of Big Rivers' regulatory filings since the closing of the Unwind Transaction and a description of Big Rivers' risk management plan and program.

9) **William Steven Seelye** (Exhibit 57). Mr. Seelye, Senior Consultant and Principal for The Prime Group, LLC, sponsors the cost of service study, the proposed allocation of the revenue increase to the rate classes, the rate design, and new rates. Mr. Seelye explains the proposal to bill the Rural Delivery Service demand charge on the basis of Coincident Peak ("CP") demands rather than Non-Coincident Peak ("NCP") demands. Mr. Seelye describes the proposed pro forma adjustment to the Smelter TIER Adjustment Charge and supports proposed changes to the MRSM and RER, and other tariff changes. Mr. Seelye describes the new proposed Non-Smelter Non-FAC PPA rate mechanism and Big Rivers' proposed adoption of the Midwest ISO Attachment O formula rate. Finally, Mr. Seelye supports the temperature normalization adjustment.

IV. FILING REQUIREMENTS

Q. Have you reviewed the answers provided in Exhibits 1-47, which address Big Rivers' compliance with the historical period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of those Exhibits for which I am identified as the sponsoring witness as part of my Direct Testimony.

V. BIG RIVERS' NEED FOR RATE RELIEF

A. OVERVIEW

Q. Please describe the present financial condition of Big Rivers.

A. Big Rivers' current rates do not provide sufficient revenues for Big Rivers to meet its financial obligations.

Q. What is Big Rivers' revenue deficiency?

A. For the twelve months ended October 31, 2010, on an adjusted basis, Big Rivers has a revenue deficiency of $39,952,927. This is explained in the Direct Testimony of Mr. Wolfram. Big Rivers is proposing to increase its base rates in order to eliminate this revenue deficiency.

Q. What is the effect of Big Rivers' proposed rates?

A. Big Rivers' proposed rates are designed to increase base rate revenues by $39,953,965 (which differs from the revenue deficiency very slightly due to the rounding of the rates). This is necessary to provide Big Rivers with sufficient margins to meet the financial requirements set forth in its debt agreements and to continue to provide reliable service to its customers. This is described further in the Direct Testimony of Mr. Seelye.

B. FINANCIAL OBLIGATIONS

Q. Why is an increase in Big Rivers' base rates necessary at this time?

A. In short, the requested increase in base rates is necessary so that Big Rivers can meet its financial obligations (including its MFIR requirement) and maintain investment grade credit ratings, as required by its debt covenants.

Q. What obligations does Big Rivers have to its creditors regarding maintenance of its financial health?

A. Big Rivers has financial covenant obligations under its First Mortgage Indenture to U.S. Bank National Association, Trustee, dated as of July 1, 2009 ("Indenture"), to the United States of America, acting through the Rural Utilities Service ("RUS") under the Amended and Consolidated Loan Contract dated as of July 16, 2009 ("RUS Loan Contract"), to the National Rural Utilities Cooperative Finance Corporation under the Revolving Line of Credit Agreement dated as of July 16, 2009, and to CoBank, ACB under the Revolving Credit Agreement dated as of July 16, 2009.

Big Rivers is required by Section 13.14 of the Indenture to establish and collect rates that will enable Big Rivers to comply with all of its covenants under the Indenture. One of those covenants is that, subject to appropriate regulatory approvals, Big Rivers establish and collect rates that are reasonably expected to yield an MFIR for each fiscal year of the company equal to at least 1.10 for the period.

The RUS Loan Contract requires Big Rivers to comply with the financial covenants in the Indenture. It also requires in Section 4.23(a) that Big Rivers maintain an investment grade credit rating from at least two rating agencies. Big Rivers currently complies with this requirement.

These obligations are described in detail in the Direct Testimony of Mr. Blackburn.

Q. Will the rates proposed by Big Rivers produce revenues that will enable Big Rivers to comply with the MFIR covenant in the Indenture?

A. Yes. The calculation of MFIR for the period of the test year, assuming the proposed rates are in effect, produces an MFIR of 1.25. Based upon the information we have about the period immediately following the date on which the new rates are anticipated to go into effect, we can reasonably expect the proposed rates to produce at least a 1.10 MFIR for 2011.

Q. Why is Big Rivers seeking a rate increase that exceeds the minimum level necessary to achieve a 1.10 MFIR?

A. Big Rivers' need to comply with the MFIR covenant is not the only consideration underlying Big Rivers' proposed rate increase. Big Rivers also must maintain its Times Interest Earned Ratio ("TIER") at a certain level in order to maintain its investment grade credit ratings. In the Unwind Transaction, Big Rivers witness Glotfelty testified that "the ratings agencies may accept a ***minimum*** annual TIER of 1.24x to achieve investment grade credit ratings." Case No. 2007-00455, Testimony of Mark W. Glotfelty, Exhibit 21 at p. 9 (emphasis added). The reasonableness of the 1.24 TIER was not challenged in the Unwind Proceeding. As explained further in the Direct Testimony of Mr. Hite, if Big Rivers' rates are not sufficient to achieve a TIER of 1.24, Big Rivers will be at risk of failing to achieve the necessary investment grade credit ratings. This could result in Big Rivers either defaulting on its obligations under its credit agreements and/or being forced to further cut costs and continue to defer maintenance on its generating units in order to achieve the required TIER and MFIR.

The pro forma adjustments proposed by Big Rivers are necessary in order to avoid a circumstance in which Big Rivers must choose between these two hazardous options.

Q. If Big Rivers' proposed rate increase proves to be greater than needed to achieve a 1.24 Contract TIER, would this result in overearning by Big Rivers?

A. No. As Mr. Hite explains more fully in his Direct Testimony, any net margins in excess of a 1.24 Contract TIER are subject to being returned to the Smelters and the Members' non-Smelter customers. Thus, the Contract TIER is effectively capped at 1.24. Moreover, as a cooperative, Big Rivers has no shareholders who could potentially be enriched by Big Rivers' rates collecting more than anticipated, so there is no incentive for Big Rivers to seek a rate increase greater than is necessary to meet its obligations.

Q. Is there any leeway in Big Rivers' request?

A. No. As Mr. Blackburn explains in his direct testimony, the difference in net margins between making a 1.25 MFIR and a default due to an MFIR below 1.10 is only $6.9 million. For a company with $523 million in annual expenses, that is a very slim (1.32%) margin of error.

Q. What are the implications for Big Rivers of failing to comply with the MFIR covenant in the Indenture?

A. Failure of Big Rivers to achieve a 1.10 MFIR can prohibit Big Rivers from borrowing money and securing it under the Indenture, even if that failure has not resulted in an Event of Default.

Q. Why would a limitation on Big Rivers' ability to secure Additional Obligations under the Indenture create a problem for Big Rivers?

A. Big Rivers is required to refinance $60,000,000 of RUS debt prior to October 1, 2012, $58.8 million in Pollution Control Bonds prior to June 1, 2013, and another $200,000,000 of RUS debt prior to January 1, 2016. These refinancing requirements are driven by reductions in the Maximum Allowed Debt Balance that occur under Big Rivers' July 16, 2009, RUS 2009 Promissory Note Series A ("RUS Series A Note") as of those dates. For Big Rivers to be in a position to refinance this debt, it must be able to secure the refinanced debt under its Indenture. If Big Rivers cannot refinance the $60,000,000 in RUS debt, it will default on its obligations under the RUS Series A Note, which will essentially create an event of default under all of Big Rivers' credit agreements. Big Rivers' cash needs, as impacted by its revenue requirements, rates and capital expenditures, will influence the timing and amount of additional borrowings. Big Rivers' inability to borrow money on a long-term, secured basis is unacceptable for a utility the size of Big Rivers that will always have periodic cash requirements for both anticipated and unanticipated needs.

Further, as described in more detail in the Direct Testimony of Mr. Spen, the credit ratings agencies and potential investors will look unfavorably on a regulated G&T cooperative with marginal investment-grade ratings that is struggling to meet its obligations under its credit agreements. This could impact both Big Rivers' ability to borrow, and/or the interest rates at which money might be available to it.

Q. What is the policy of Big Rivers with respect to compliance with the financial covenants of its loan agreements?

A. Big Rivers' policy is to be in full compliance with the financial covenants of its loan agreements, and it believes that any other policy would be imprudent.

Q. Do you believe Big Rivers can retain its investment grade credit ratings if the Commission approves the proposed rate adjustment?

A. Yes. As Mr. Spen notes in his Direct Testimony, it remains essential that Big Rivers be diligent in making good business decisions, achieving solid business performance and maintaining healthy financial ratios. The proposed rate relief would provide the necessary demonstration in this regard to maintain Big Rivers' current credit ratings, at least in the near term.

Further, Mr. Spen notes that the credit markets generally recognize the importance of Big Rivers having sufficient revenue and cash flow to meet its operating budget, pay debt service and achieve its financial coverage requirements. The approval of Big Rivers' rate proposal would most certainly be viewed positively by both the markets and the rating services.

Q. What will be the consequence if the Commission does not approve the full proposed rate adjustment?

A. Without the full rate increase requested by Big Rivers, Big Rivers may lose one or more of its investment grade credit ratings, which would likely mean, at a minimum, higher borrowing costs. If Big Rivers does not maintain two investment grade credit ratings, it will be required by the RUS to file promptly for additional rate relief that will position it to obtain those investment grade credit ratings. In the worst case, loss of investment grade credit ratings could jeopardize the solvency and indeed the very existence of Big Rivers.

C. OTHER DRIVERS

Q. Are there other drivers behind the need for the requested rate relief?

A. Yes. Other major drivers include the need to perform maintenance on the Big Rivers generating units and to manage the exposure of Big Rivers to additional costs attendant upon membership in the Midwest ISO.

While the reliability of the Big Rivers generating facilities has been excellent, it is imperative that Big Rivers perform adequate maintenance on the units. Particularly, Big Rivers needs to perform the maintenance that was deferred during the test year due to economic circumstances. Big Rivers is requesting a pro forma adjustment in this proceeding to provide for the inclusion of a prudent level of maintenance costs, because the level of maintenance costs in the test year is inadequate on a going-forward basis. It is essential to provide sufficient revenue in this proceeding to allow the maintenance to be performed to ensure that the generating units operate reliably, as Mr. Berry explains in his Direct Testimony.

Without the additional revenue requirement associated with the pro forma adjustment, Big Rivers will be required to reduce expenditures in order to meet its MFIR and maintain credit ratings as required in its long-term debt agreements. If it is not granted an adequate revenue increase in this proceeding, the only option available to Big Rivers to meet its MFIR requirements would be to reduce costs, including plant maintenance, which would have an adverse impact on reliability.

Finally, in order to meet its NERC Contingency Reserve obligations, Big Rivers became a transmission-owning member of the Midwest ISO effective December 1, 2010. Membership in the Midwest ISO increases Big Rivers' cost exposure, which further supports the need for the requested rate relief in this proceeding.

D. OTHER EFFORTS

Q. Has Big Rivers satisfied the requirements of the Unwind Order in Case No. 2007-00455?

A. Yes. Big Rivers has satisfied all of the Unwind Commitments noted in the Ordering Paragraphs and in Appendix A of the Unwind Order. The manner in which Big Rivers complied with each requirement is detailed in the Direct Testimony of Mr. Blackburn.

Q. Has Big Rivers satisfied the requirements of the Commission's Order in the Midwest ISO proceeding in Case No. 2010-00043?

A. Yes. The manner in which Big Rivers has complied with these requirements is also detailed in the direct testimony of Mr. Blackburn.

Q. Has Big Rivers otherwise met its responsibilities for submitting filings with this Commission since the closing of the Unwind Transaction?

A. Yes. Big Rivers has consistently fulfilled its filing obligations, including the Fuel Adjustment Clause filings, Environmental Surcharge filings, and the 2010 Integrated Resource Plan, as described in detail in the Direct Testimony of Mr. Yockey.

Q. Has Big Rivers undertaken efforts to manage its costs and thus avoid or delay the need for the requested rate relief?

A. Yes. Since the closing of the Unwind Transaction, Big Rivers has very closely managed its operations in order to purge unnecessary costs from the business. As noted in the Direct Testimony of Mr. Berry, one of the steps taken to manage to the financial commitments during the test year was to defer certain generation unit maintenance. However, Big Rivers has exhausted its options for further reducing or limiting costs while still maintaining its ability to reliably operate its generating facilities and now must seek an increase to its base rates.

VI. SUMMARY OF RELIEF REQUESTED

Q. How did Big Rivers develop the rates proposed in this proceeding?

A. To develop the rates proposed herein, Big Rivers conducted a fully allocated embedded cost of service study. This is described in detail in the Direct Testimony of Mr. Seelye. Big Rivers has three major rate classifications – Rural Delivery Service (RDS) ("Rurals"), Large Industrial Customer Rate (LIC) ("Large Industrials"), and the special contracts with the Smelters. The cost of service study indicates that the rate of return for the Rurals is lower than the rate of return for the Large Industrials. Big Rivers is proposing to take steps in this proceeding to move the rates of return closer together. More specifically, Big Rivers is proposing rates that will eliminate some of the rate of return differential between the Rurals and the Large Industrials. This is described further in the Direct Testimony of Mr. Seelye. It would be Big Rivers' intent to continue to close the remaining gap in future rate proceedings.

Q. Is Big Rivers proposing to revise the base demand and energy charges for the Rural and Large Industrial tariffs?

A. Yes. For the Rural rates, Big Rivers is proposing to increase the demand charge from \$7.370 per kW per month (billed on the basis of NCP demand) to \$10.1890 per kW per month (billed on the basis of CP demand). Big Rivers is proposing to reduce the energy charge from \$0.02040 per kWh to \$0.019524 (after the roll-in of the Non-FAC PPA base described below; otherwise this rate remains \$0.02040/kWh). For the Large Industrial rates, Big Rivers is proposing to increase the demand charge from \$10.1500 per kW per month to \$10.8975 per kW per month and to increase the energy charge from \$0.013715 per kWh to \$0.014885 per kWh (again, after the roll-in of the Non-FAC PPA base described below; otherwise this rate increases to \$0.015761/kWh).

Q. Have any other adjustments been made that affect pro forma revenue for the Smelters?

A. Yes. Big Rivers is proposing to reduce the TIER Adjustment Charges billed under Section 4.7.1 of the Smelter Agreements by 50 percent, which is equivalent to moving the Smelters' TIER Adjustment to the middle of the current contract bandwidth. Positioning the Smelters in the middle of the bandwidth allows Big Rivers to draw extra revenue from the Smelters if adverse conditions threaten Big Rivers' ability to make TIER between rate cases and allows the contract with them to function as envisioned by Big Rivers when it was negotiated. This is described further in the Direct Testimony of Mr. Seelye.

Q. Is Big Rivers proposing to revise the base purchased power cost used in the Non-FAC PPA?

A. Yes. Specifically, Big Rivers is proposing to reduce the Non-FAC PPA from $0.00175 per kWh to $0.000874 per kWh. This revenue neutral "roll in" will result in a corresponding reduction in the energy charges for the three rate classifications. This is described in detail in the Direct Testimony of Mr. Seelye.

Q. Is Big Rivers proposing a new rate mechanism for the treatment of any balances in the Non-FAC PPA Regulatory Account established at the closing of the Unwind Transaction?

A. Yes. Big Rivers is proposing a new mechanism called the "Non-Smelter Non-FAC PPA" that will allow it to amortize any balances in the Non-FAC PPA Regulatory Account for the Rurals and Large Industrials every 12 months rather than waiting until the next general rate case to amortize the balances. This is described in detail in the Direct Testimony of Mr. Seelye.

Q. Given all of the proposed changes outlined above, what is the total proposed increase in revenue that Big Rivers is requesting in this proceeding?

A. The requested increase is comprised of the each of the components outlined above.

The first component reflects the increase proposed in base rates. For this component, Big Rivers is requesting an annual increase of $39,953,965.

The second component reflects the proposed change in the TIER Adjustment Charge for the Smelters. This component is a decrease and will offset the proposed increase in base rates, reducing it by $7,114,653 to $32,839,312.

The third component reflects the estimated credits from the amortization of the Non-FAC PPA regulatory account balance. This component is a net decrease, reducing the proposed increase by an additional $3,236,077. This places the total proposed increase at $29,603,235 or 6.85% overall. This corresponds to an increase of $11,831,935 (or 10.71%) for the Rurals, $2,332,557 (or 5.94%) for the Large Industrials, and $15,438,743 (or 5.47%) for the Smelters.

Furthermore, Big Rivers is proposing to lower the Non-FAC PPA base cost from $0.00175/kWh to $0.000874/kWh, which will reduce the total increase by an additional $2,959,159. This would place the total proposed increase at $26,644,076 or 6.17% overall. This corresponds to an increase of $9,686,481 (or 8.77%) for the Rurals, $1,518,852 (or $3.87%) for the Large Industrials, and $15,438,743 (or 5.47%) for the Smelters. These values are all tabulated in the Direct Testimony of Mr. Seelye, in Exhibit Seelye-6.

Q. How will the proposed rate increases affect the retail rates of Big Rivers' Members?

A. The average impact on the Members' retail rates will result in a lower overall percentage increase than what is proposed by Big Rivers for the wholesale rates. Because Big Rivers' Members' retail rates also include the cost of providing distribution services to their members, the percentage impact of the Big Rivers rate increase will be diluted at the retail level. Big Rivers estimates that on average its proposed rate increase will result in an increase of approximately 6.8% for a typical residential customer with a monthly usage of 1,300 kWh. This is an estimate and is discussed in the Direct Testimony of Mr. Seelye.

Q. Is Big Rivers proposing any changes to the Member Rate Stability Mechanism or the Rural Economic Reserve?

A. Yes. Big Rivers is proposing changes to both the MRSM and the RER so that the two mechanisms operate more seamlessly. The MRSM was established for the purpose of using a $157 million economic reserve to offset any net billing impacts to the Rurals and the Large Industrials related to the FAC and Environmental Surcharge. The RER was established for the purpose of returning a $60.9 million reserve to the Rurals once the MRSM terminates. Big Rivers is proposing modifications to these mechanisms so that there will not be any discontinuities in billings to the Rurals as a result of transitioning from the MRSM to the RER. This is described in detail in the Direct Testimony of Mr. Seelye.

Q. Is Big Rivers proposing a pro forma adjustment to test year expenses for Energy Efficiency Programs?

A. Yes. This adjustment reflects the commitment of Big Rivers to implement Energy Efficiency and Demand-Side Management ("DSM") Programs, as outlined in the Big Rivers 2010 Integrated Resource Plan. This is described in detail in the Direct Testimony of Mr. Blackburn.

Q. Please describe the commitment that Big Rivers is prepared to make regarding Energy Efficiency and DSM Programs.

A. Contingent upon the acceptance of this pro forma adjustment to test year expenses and its inclusion in base rates, Big Rivers commits that it will spend $1 million annually on the Energy Efficiency and DSM programs as proposed in the 2010 Integrated Resource Plan, and/or any subsequent program filings, to create and promote incentives for a number of consumer energy efficiency measures.

Q. Why is Big Rivers proposing this pro forma adjustment at this time?

A. Big Rivers believes that providing Energy Efficiency offerings to our Members is a high priority and proposes to include this pro forma adjustment to better enable Big Rivers to implement these programs. The focus at this time is on establishing the programs that were outlined in the 2010 IRP quickly and effectively, consistent with the outcome of the 2010 IRP proceeding.

VII. CONCLUSION

Q. Please summarize your testimony.

A. Since the close of the Unwind Transaction, Big Rivers has satisfied all of the applicable commitments noted by the Commission in Unwind Order. Big Rivers has historically maintained relatively low rates, and has aggressively managed its costs since the closing of the Unwind Transaction. Big Rivers has deferred costs as much as possible and has exhausted its options for delaying the need to increase base rates. At this time, Big Rivers must increase its base rates to meet its debt covenants and to allow it to perform necessary maintenance on its generating facilities.

Q. Do you have any closing comments?

A. Yes. Big Rivers does not take the decision to seek this increase lightly. The full amount of base rate increases is simply necessary at this time in order for Big Rivers to adequately recover its costs and to meet its existing debt covenants with its creditors. The rates proposed by Big Rivers are fair, just and reasonable and should be approved by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

MARK ALAN BAILEY

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Big Rivers Electric Corp. Henderson, Kentucky Oct. 2008 – present	**President & CEO**
Big Rivers Electric Corp. Henderson, Kentucky June 2007 – Oct. 2008	**Executive Vic President & COO**
Kenergy Corp. Henderson, Kentucky May 2004 – May 2007	**President & CEO** *Responsible to an elected 11 member board for all facets of operations of a distribution electric cooperative serving approximately 54,000 members including 19 large industrial customers in portions of 14 counties in western Kentucky with ~ 160 employees, a peak demand of approximately 1,300 MW, annual kwh sales in excess of 9.4 billion, $300 million in annual revenue, and $210 million in assets
American Electric Power Service Corporation Columbus, Ohio June 2000 - April 2004	**Vice President Transmission Asset Management** *Managed AEP's $2.5B transmission and substation assets located in eleven states, including $100M annual O&M and $250M capital expenditure decisions, as well as engineering and maintenance standards, annual maintenance and capital plans, development of strategic, business and incentive plans, system planning and interconnection agreements, regulatory and legislative policy formation and testimony, and all transmission related contracts
American Electric Power Service Corporation Columbus, Ohio Jan. 1998 - May 2000	**Managing Director, Energy Delivery and Customer Relations** *Responsible for administration of the Energy Delivery and Customer Relations business group consisting of the Transmission, Distribution, Marketing, System Operations, Public Relations, Regulatory functions and the state Presidents' offices including development of strategic, business and incentive plans, operational metrics, performance targets and monitoring systems *Managed Transmission and Distribution Materials Management organization. *Testified before 4 state Commissions in support of AEP's merger w/ CSW
American Electric Power Service Corporation Columbus, Ohio Jan. 1996 - Dec. 1997	**Director - Regions** *Directed the reorganized AEP'S six southern distribution regions serving nearly 1,300,000 customers in portions of 5 states with 2,700 company and 2,500 contractor employees *Oversaw the Transmission and Distribution Materials Management Organization
Indiana Michigan Power Fort Wayne, Indiana Oct. 1994 - Dec. 1995	**Vice President, Administration** *Oversaw Marketing, Customer Services, Accounting, Rates, and Purchasing and Materials Management Departments as well as the Budgeting Section *Chaired the company's Political Action Disbursements Committee *Coordinated operating company administrative support for the company's three coal fired and one nuclear generating stations (6,200MW)

Indiana Michigan Power Fort Wayne, Indiana 1989 - Sept. 1994	**Vice President, Operations** *Directed four operating divisions serving nearly 520,000 customers in 28 counties in Indiana and Michigan and a total of ~ 1,300 employees *Oversaw Transmission and Distribution, Purchasing and Materials Management, System Operations, General Services and Land Management Departments at corporate headquarters *Coordinated operating company administrative support for the company's three coal fired, one nuclear and five hydro power plants (6.200MW)
Oho Power Columbus, Ohio 1988 – 1989	**Executive Assistant to the President** *Assisted the AEP Executive Vice President - Operations performing studies and analyses such as ramifications of merging Ohio Power and Columbus Southern Power operating companies and design of a management incentive compensation system *Lobbied on behalf of Ohio Power with the Ohio General Assembly
Ohio Power Cambridge, MA 1987 – 1988	**Division Manager** *Completed course work leading to attainment of a Masters Degree in Management as a Sloan Fellow at the Massachusetts Institute of Technology
Oho Power Tiffin, Ohio 1985- 1987	**Division Manager** *Managed all aspects of providing electrical service to 58,000 customers through five operating units consisting of 210 employees
Ohio Power Canton, Ohio 1983 – 1985	**Administrative Assistant to the President** *Coordinated operating company administrative support for the company's five fossil fired power plants (8,120MW) *Oversaw operation and maintenance of the company's two unit, 48 MW hydro plant *Assisted the President with various studies and assignments
Cardinal Operating Co. Cardinal Plant Brilliant, Ohio 1981 - 1983	**Performance Superintendent** *Directed department of 65 employees responsible for installation and maintenance of the plant's instruments and controls, engineering and thermal performance, and laboratory operations at the three unit, coal fired 1,860 MW plant *Directly supervised start-up & shut-downs of the 600 MW supercritical units
Ohio Power Muskingum River Plant Beverly, Ohio 1979 - 1981	**Production Superintendent** *Directed department responsible for operations of a five unit, coal fired 1,460 MW plant *Directly supervised start-ups & shut-downs of the plant's 600 MW supercritical unit, wrote plant operating procedures and trained operators following major modifications of the 600 MW Unit 5 steam generator & precipitator addition
Ohio Power Gavin Plant Cheshire, Ohio 1975 – 1979	**Performance Engineer** *Various engineering positions of increasing responsibility at the two unit, 2,600 MW coal fired plant. Major areas of involvement included analyzing thermal performance, instrument and control installation and maintenance *Wrote plant operating procedures for all the AEP system's 1,300 MW supercritical units
Ohio Power Portsmouth, Ohio 1974 - 1975	**Electrical Engineer** *Designed, laid out and specified material for construction of distribution facilities to serve retail customers in the Portsmouth division

Education:

*The Massachusetts Institute of Technology, Cambridge, Massachusetts
Masters of Science in Management, 1988
*The Ohio Northern University, Ada, Ohio
Bachelor of Science in Electrical Engineering with Distinction, 1974

Honors and Activities:

*Board member – ACES Power Marketing
*Member of Tau Beta Pi National Engineering Honorary
*Member - Order of Kentucky Colonels
*Board member - Henderson Habitat for Humanity
*Board member – Kentucky Association of Electric Cooperatives
*Board member – Methodist Hospital, Henderson, Kentucky
*Board member - Methodist Hospital Foundation
*Board member - Leadership Kentucky
*Board member – National Renewables Cooperative Organization
*Board member - Kentucky Community & Technical College Foundation
*Board member – Henderson Community & Technical College Foundation
*Member- Henderson Rotary Club

February 2011

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

DIRECT TESTIMONY

OF

C. WILLIAM BLACKBURN
SENIOR VICE PRESIDENT FINANCIAL & ENERGY SERVICES
& CHIEF FINANCIAL OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
C. WILLIAM BLACKBURN

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DIRECT TESTIMONY

OF
C. WILLIAM BLACKBURN

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is C. William Blackburn. I am employed by Big Rivers Electric Corporation ("Big Rivers") at 201 Third Street, Henderson Kentucky, 42420, as its Senior Vice President Financial & Energy Services and Chief Financial Officer. I have held this position since February 2009, just prior to the closing of the transaction that unwound Big Rivers' 1998 lease of its generating units to E.ON U.S., LLC ("E.ON") and its affiliates in Case No. 2007-00455, *In the Matter of: The Applications of Big Rivers Electric Corporation for: (1) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (2) Approval of Transactions, (3) Approval to Issue Evidences of Indebtedness, and (4) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing, Inc. for Approval of Transactions* (the "Unwind Proceeding" or the "Unwind Transaction"). Prior to February 2009, I served as Vice President Financial Services, Chief Financial Officer, and Interim Vice President Power Supply. I assumed that position in November 2005. Prior to that, I held the position of Vice President Power Supply since July 1998. Altogether I have been employed by Big Rivers for a total of 33 years.

Q. Have you previously testified before this Commission?

A. Yes. I have testified on behalf of Big Rivers many times before the Kentucky Public Service Commission ("KPSC" or the "Commission"), including fuel hearings, environmental cases, rate cases, and transmission cases. Most recently I sponsored testimony and responses to discovery in Case No. 2010-00043, *In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of Its Transmission System to Midwest Independent Transmission System Operator, Inc. ("Midwest ISO".)*

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (i) support certain Filing Requirements pursuant to 807 KAR 5:001; (ii) generally describe Big Rivers' financial obligations; (iii) describe the status of each of the requirements or commitments applicable to Big Rivers ("Unwind Commitments") pursuant to the Commission's Order dated March 6, 2009, in the Unwind Proceeding ("Unwind Order"); (iv) describe the status of each of the commitments or restrictions applicable to Big Rivers pursuant to the Commission's Order dated November 1, 2010 in Case No. 2010-00043 ("Midwest ISO Order"); (v) provide a history of Big Rivers' rates; (vi) summarize the Service Agreements in place between Big Rivers and two large aluminum smelters, Century Aluminum of Kentucky General Partnership ("Century") and Alcan Primary Products Corporation ("Alcan") (collectively, "Smelters"); (vii) discuss Big Rivers' plans for managing the risk of one or both Smelters terminating their respective Service Agreements; and (ix) support certain proposed pro forma adjustments to test year expenses.

Q. Please summarize your testimony.

A. While Big Rivers has investment grade ratings today, it is imperative that Big Rivers maintain those investment grade credit ratings in the future. A cornerstone to maintaining its investment grade rating is for Big Rivers to have sufficient revenue to support not only its transmission and production operations and maintenance expenses but also to generate margins than will achieve an acceptable Margin for Interest Ratio ("MFIR"). Anything less would provide an opportunity for Big Rivers' credit ratings to fall below investment grade. If an adequate revenue increase is not granted, Big Rivers will again find itself in the position of reducing expenses, including plant maintenance, in order to meet its financial requirements.

III. <u>FILING REQUIREMENTS</u>

Q. Have you reviewed the answers provided in Exhibits 1-47, which address Big Rivers' compliance with the historical period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of Exhibits 1-47 for which I am identified as the sponsoring witness as part of this Direct Testimony.

IV. FINANCIAL OBLIGATIONS

Q. What obligations does Big Rivers have to its creditors regarding maintenance of its financial health?

A. Big Rivers has financial covenant obligations under its First Mortgage Indenture to U.S. Bank National Association, Trustee, dated as of July 1, 2009 ("Indenture"), to the United States of America, acting through the Rural Utilities Service ("RUS") under the Amended and Consolidated Loan Contract dated as of July 16, 2009 ("RUS Loan Contract"), to the National Rural Utilities Cooperative Finance Corporation ("CFC") under the Revolving Line of Credit Agreement dated as of July 16, 2009 ("CFC Revolving Credit Agreement"), and to CoBank, ACB ("CoBank") under the Revolving Credit Agreement dated as of July 16, 2009 ("CoBank Revolving Credit Agreement").

Q. What financial covenants has Big Rivers undertaken in the Indenture?

A. Big Rivers is required by Section 13.14 of the Indenture to establish and collect rates that will enable Big Rivers to comply with all of its covenants under the Indenture. One of those covenants is that, subject to appropriate regulatory approvals, Big Rivers establish and collect rates that are reasonably expected to yield a MFIR for each fiscal year equal to at least 1.10. "Margins for Interest Ratio" is defined in the Indenture as, for any period, (i) the sum of (a) Margin for Interest plus (b) Interest Charges, divided by (ii) Interest Charges. Excerpts from relevant sections of the Indenture, including Section 13.14 and the definition of Margins for Interest Ratio, are appended to my testimony as Exhibit Blackburn-1.

Q. What financial covenants has Big Rivers undertaken in the RUS Loan Contract?

A. The RUS Loan Contract requires Big Rivers to comply with the financial covenants in the Indenture. It also requires in Section 4.23(a) that Big Rivers maintain an investment grade credit rating from at least two rating agencies. Big Rivers currently complies with this requirement.

Q. What financial covenants has Big Rivers undertaken in the $50 million CFC Revolving Credit Agreement?

A. Among other things, Big Rivers is required to maintain a MFIR of no less than 1.10 and an equity ratio of no less than 12%. To obtain an advance of funds under the CFC Revolving Credit Agreement, Big Rivers must certify that it is not in default in any material respect under any agreement to which it is a party and no event or condition exists which constitutes a default, or with the giving of notice or lapse of time or both would constitute a default. The CFC Revolving Credit Agreement expires July 15, 2014.

Q. What financial covenants has Big Rivers undertaken in the $50 million CoBank Revolving Credit Agreement?

A. Under the terms of the CoBank Revolving Credit Agreement, Big Rivers must maintain a debt service coverage ratio of not less than 1.20 to 1.00, maintain a $35 million transition reserve which will be utilized to offset any cost and expenses related to a termination of a Smelter power contract, and maintain a ratio of equity to total assets of not less than 0.15 to 1.00. To obtain an advance of funds under the CoBank Revolving Credit Agreement, Big Rivers must certify that there is no change in the financial position of Big Rivers that could reasonably be expected to have a material adverse effect on the ability of Big Rivers to perform its obligations under any loan document to which Big Rivers is a party. The interest rate paid by Big Rivers on the unpaid principal balance of loans under the CoBank Revolving Credit Agreement is based upon the London Interbank Offered Rate ("LIBOR") plus a LIBOR Margin tied to Big Rivers' credit ratings; the better the rating the lower the margin. The Cobank Revolving Credit Agreement expires on July 16, 2012.

Q. Will the rates proposed by Big Rivers produce revenues that will enable Big Rivers to comply with the MFIR covenant in the Indenture?

A. Yes. The calculation of MFIR for the period of the test year, assuming the proposed rates are in effect, produces a MFIR of 1.25. That calculation is shown in Exhibit Blackburn-2 to my testimony. Based upon the information we have about the period immediately following the date on which the new rates are anticipated to go into effect, we can reasonably expect the proposed rates to produce at least a 1.10 MFIR for 2011.

Q. What was Big Rivers' Margins for Interest Ratio in its last fiscal year?

A. Big Rivers' MFIR for its last fiscal year, calendar year 2010, was 1.15 based upon margins of $7.0 million. Big Rivers attained its MFIR for that period by very carefully planning and executing its business strategies. As a result of the lower prices for power in the wholesale market it was necessary for Big Rivers to take extraordinary steps to lower its expenses. A major part of the business strategy was corporate-wide cost-cutting and implementation of cost deferral measures, including postponing planned generating unit maintenance outages, transmission maintenance, and administrative & general discretionary expenses.

Q. What is the difference in margins that resulted in a MFIR of 1.15, rather than 1.10 for the fiscal year ending 2010?

A Big Rivers' MFIR for the fiscal year 2010 would have been 1.10 if its margins had been only $2.3 million less than they were. This is a very narrow margin (0.4%) of error for a business with a 2010 annual cost of service of $523 million.

Big Rivers cannot earn more than a 1.24 Contract TIER because of the Smelter Agreement TIER Adjustment mechanism, and the rebate mechanism built into the Smelter agreements and Big Rivers' tariffs to its Members. A 1.24 Contract TIER roughly equates to a 1.25 MFIR. The difference in margins required for Big Rivers to achieve a 1.10 MFIR in 2010, $4.4 million, and the margins Big Rivers would have earned if it had achieved a 1.24 Contract TIER, $11.3 million, is only $6.9 million, or 1.3% of Big Rivers' 2010 cost of service.

Q. What are the implications for Big Rivers of failing to comply with the MFIR covenant in the Indenture?

A. As mentioned above, subject to regulatory approvals, Big Rivers is required to always establish and collect rates that are reasonably expected to yield a MFIR of at least 1.10. If Big Rivers has complied with that covenant, but still fails to achieve the minimum required MFIR of 1.10 in a fiscal year, Big Rivers can avoid an Event of Default under the Indenture by immediately seeking rates that will comply with its covenants in the Indenture.

Q. Does this mean that there is no practical penalty for Big Rivers failing to achieve a MFIR of 1.10 in a fiscal year?

A. No. Failure of Big Rivers to achieve a 1.10 MFIR can prohibit Big Rivers from borrowing money and securing it under the Indenture, even if that failure has not resulted in an Event of Default. More specifically, before Big Rivers can issue "Additional Obligations" secured by the Indenture, Big Rivers must be able to deliver a certificate that the MFIR is not less than 1.10 for one of the following periods of time: (i) the fiscal year of Big Rivers immediately preceding the fiscal year in which the application to deliver Additional Obligations is made, or (ii) if the Application to deliver Additional Obligations is made within ninety days after the end of the fiscal year, the second preceding Big Rivers' fiscal year, or (iii) any twelve consecutive calendar months during the period of fifteen calendar months immediately preceding the first day of the calendar month in which the Application to deliver Additional Obligations is made.

Q. Why would a limitation on Big Rivers' ability to secure Additional Obligations under the Indenture create a problem for Big Rivers?

A. Big Rivers is required to refinance $60,000,000 of RUS debt prior to October 1, 2012, and another $200,000,000 of RUS debt prior to January 1, 2016. These refinancing requirements are driven by reductions in the Maximum Allowed Debt Balance that occur under Big Rivers' July 16, 2009, RUS 2009 Promissory Note Series A ("RUS Series A Note"). For Big Rivers to be in a position to refinance this debt, it must be able to secure the refinanced debt under its Indenture. See the Direct Testimony of Mr. Alan Spen in Exhibit 50, page 14. If Big Rivers cannot refinance the $60,000,000 of

RUS debt, it will default on its obligations under the RUS Series A Note, which will essentially create an event of default under all of Big Rivers' credit agreements. Big Rivers' inability to borrow money on a long-term, secured basis is unacceptable for a utility the size of Big Rivers that will always have periodic cash requirements for both anticipated and unanticipated needs. The risk to Big Rivers resulting from an inability to borrow money on a long-term secured basis is one of the principal reasons Big Rivers pursued the Unwind Transaction.

Further, as described in more detail in the Direct Testimony of Mr. Alan Spen, the credit ratings agencies and potential investors will look unfavorably on a regulated Generation & Transmission cooperative with marginal investment-grade ratings that is struggling to meet its obligations under its credit agreements. This could impact both Big Rivers' ability to borrow, and/or the interest rates at which money might be available to it.

Q. Are there other negative implications for Big Rivers if it fails to comply with the financial covenants under the Indenture and the RUS Loan Contract?

A. Yes. Big Rivers carries modest cash operating reserves in favor of relying on the two, $50 million revolving credit agreements with CoBank and CFC. Access to funds under those agreements, and Big Rivers' ability to renew those agreements after they expire in 2012 and 2014, respectively, could be adversely affected by Big Rivers failing to comply with its financial covenants under the Indenture and the RUS Loan Contract. See Exhibit 50, page 14.

Q. What is the policy of Big Rivers with respect to compliance with the financial covenants of its loan agreements?

A. Big Rivers' policy is to be in full compliance with the financial covenants of its loan agreements, and it believes that any other policy would be imprudent.

V. UNWIND COMMITMENTS

Q. Did Big Rivers agree to certain commitments pursuant to the Unwind Order?

A. Yes. Big Rivers agreed to certain requirements included in both the Ordering Paragraphs and Appendix A of the Unwind Order. The relevant Ordering Paragraphs are numbers four and five. Appendix A includes twenty-four commitments.

Q. Has Big Rivers satisfied these commitments pursuant to the Unwind Order?

A. Yes. Big Rivers has satisfied all of the Unwind Commitments that apply at this point in time. Certain other commitments -- in particular the requirements of Appendix A Items 14, 17, 18, 20 and 21 -- require Big Rivers to advise the Commission on a timely basis of any material changes to specific criteria or other items which to date have not occurred. Big Rivers remains committed to adhering to these open commitments on a prospective basis.

Q. Has Big Rivers satisfied the requirement in Ordering Paragraph 4?

A. Yes. Ordering Paragraph 4 required that upon the closing of the Unwind Transaction, Big Rivers establish the journal entries and regulatory accounts, including but not limited to, the regulatory liability to establish the Rural Economic Reserve, and deposit $60.9 million in the Rural Economic Reserve, all in accordance with the findings in the

Unwind Order. Big Rivers established the necessary journal entries and regulatory accounts in accordance with this requirement, as evidenced in the financial statements supported in the Direct Testimony of Mr. Mark A. Hite. Big Rivers deposited $60.9 million in the reserve account at the closing of the Unwind Transaction pursuant to Appendix B of the Unwind Order.

Q. Has Big Rivers satisfied the requirement in Ordering Paragraph 5?

A. Yes. Ordering Paragraph 5 required Big Rivers to file its revised tariff sheets, including a rate mechanism to implement the Rural Economic Reserve, within 20 days of the closing of the Unwind Transaction. Big Rivers filed its revised tariffs on August 3, 2009, and is requesting authority to adjust those rates and tariffs in this proceeding.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 1?

A. Yes. This item required Big Rivers to use the actual expenses reported by Western Kentucky Energy Corp. ("WKEC") to calculate the fuel adjustment clause charges and the environmental surcharge for the applicable period until Big Rivers' actual costs were available. This requirement stems from the inherent two-month lag between the expense month and the billing month for both adjustment clauses. Big Rivers used WKEC's actual expenses for the adjustment clauses for the expense month of June 2009; the adjustment clauses were calculated and filed with the Commission in July 2009, and became effective on Members' bills sent in August 2009. Big Rivers also used WKEC actual expenses for the first half of the expense month of July 2009. At the closing of the Unwind Transaction on July 16, 2009, when Big Rivers' actual costs became available, Big Rivers began to use its own actual expenses for the adjustment clauses. The adjustment clauses for the expense month of July 2009 were calculated and filed with the Commission in August 2009 and became effective on member bills in September 2009. Thus Big Rivers relied upon actual expenses from WKEC to calculate both adjustment clauses until Big Rivers' actual costs were available.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 2?

A. Yes. This item specified that the Economic Reserve will be funded at closing of the Unwind Transaction by an amount no less than $157 million. The Economic Reserve was funded at the closing of the Unwind Transaction at $157 million.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 3?

A. Yes. This item required Big Rivers to not sell SO_2 allowances in its inventory (excluding the 14,000 SO_2 allowances acquired in conjunction with the Unwind Transaction) unless the sale is cost-effective based on a written policy which reflects short- and long-term allowance needs and prices. Big Rivers did not sell any SO_2 allowances in its inventory.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 4?

A. Yes. This item required Big Rivers to account on its books for emission allowances it acquires in the Unwind Transaction in accordance with the RUS Uniform System of Accounts. Big Rivers accounted for these emission allowances on its books in accordance with the RUS Uniform System of Accounts, as further described in the Direct Testimony of Mr. Mark A. Hite.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 5?

A. Yes. This item required Big Rivers not to close the Unwind Transaction until the Commission reviewed and approved any change to the Station Two contract amendments filed on October 9, 2008. Big Rivers complied with this requirement.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 6?

A. Yes. This item required Big Rivers to maintain a sound and constructive relationship with the labor organization(s) representing certain employees of WKEC, and Big Rivers has done so.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 7?

A. Yes. This item required Big Rivers to bargain in good faith with IBEW during any collective bargaining sessions, and Big Rivers has done so.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 8?

A. Yes. This item required Big Rivers to continue to employ in the conduct of its business the level of workforce required to safely and professionally operate its facilities. Big Rivers is doing so and is presently undertaking efforts to fill open positions in order to support the workforce level in the future. This is further described in the pro forma adjustment for labor and labor-related items outlined in the Direct Testimony of Mr. Mark A. Hite. Furthermore, Big Rivers considers this requirement to be consistent with its broad obligations regarding the provision of service, acceptable standards, and good accepted engineering practices pursuant to 807 KAR 5:041, Electric.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 9?

A. Yes. This item required Big Rivers to finalize its due diligence on the generating facilities and sites using all resources available to it, and to not waive any of its rights under the Termination Agreement, Sections 10.3(dd) or 10.3(ee), to require that the generating facilities be in good condition and that there is a proper demonstration of their capability. Big Rivers completed its due diligence and did not waive its rights under the aforementioned sections of the Termination Agreement. Furthermore, the

Big Rivers generating facilities are in good condition and properly demonstrate their capability, as further discussed in the Direct Testimony of Mr. Robert W. Berry.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 10?

A. Yes. This item required Big Rivers to provide a written notice to the Commission within 24 hours of the closing of the Unwind Transaction, setting forth the date of the closing. Big Rivers provided this notice on July 17, 2009, which set forth the date of the closing as July 16, 2009, at 11:59 PM.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 11?

A. Yes. This item required Big Rivers to file a report with the Commission within 10 days of the closing of the Unwind Transaction stating that all of the conditions precedent to the closing were satisfied or waived. By letter dated July 24, 2009, Big Rivers reported to the Commission in accordance with this requirement that all closing conditions had been satisfied, waived or accepted.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 12?

A. Yes. This item required Big Rivers to file, within 3 years of closing the Unwind Transaction, a general review of its financial operations and its tariffs, including with that filing a new depreciation study and an analysis of Big Rivers' financial condition and rates assuming the study's results are implemented. Big Rivers satisfies this commitment by way of the application, testimony and exhibits in this filing (Case No. 2011-00036).

Q. Has Big Rivers satisfied the requirement in Appendix A Item 13?

A. Yes. This item required Big Rivers to file a new Integrated Resource Plan ("IRP") no later than November 15, 2010, and to file on September 15, 2009, and again on March

15, 2010, reports setting forth the information required by 807 KAR 5058, Section 8(2), and the details of its economic development activities. On November 15, 2010, Big Rivers filed its IRP, which is currently an open proceeding in Case No. 2010-00443. Big Rivers also made the other requisite filings, and in this proceeding makes reference to the costs associated with economic development activities in a pro forma adjustment described in the Direct Testimony of Mr. Mark A. Hite.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 14?

A. Yes. This item required Big Rivers to advise the Commission, in conjunction with the filing of its IRPs, of any material changes to the RUS' criteria for the financing of both new coal-fired plants and existing coal-fired plants on a timely basis. To date there have been no material changes to these criteria. Big Rivers will continue to monitor these criteria in connection with future IRPs and will advise the Commission of any material changes to these criteria should they occur.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 15?

A. Yes. This item required Big Rivers to file with the Commission the "Big Rivers New Financial Model" within 60 days of the closing of the Unwind Transaction, and by April 30 of each year thereafter, through the date on which Big Rivers files a case for a general adjustment of its rates and thereafter as may be required by the Commission. By order dated September 1, 2009, the Commission granted Big Rivers a 30 day extension of time to meet this filing requirement. Big Rivers filed an updated New Financial Model on October 14, 2009, and again on April 27, 2010, in accordance with this commitment. Both of the filed New Financial Models included a general base rate increase greater than 11% for members effective on January 1, 2012. The relief sought in this case is generally consistent with the projections included in both the October 2009 and April 2010 New Financial Model filings.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 16?

A. Yes. This item required Big Rivers to fund, initiate, and maintain a risk management plan and program, which would include the ability to identify and address the impact of contingencies including but not limited to fuel prices, cost exposure for environmental remediation programs (both existing and contemplated), and any other material risks pertaining to Big Rivers. Big Rivers has initiated and maintains this risk management plan and program consistent with those requirements. The plan is discussed at length in the Direct Testimony of Mr. Albert M. Yockey.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 17?

A. Yes. This item required Big Rivers to provide to the Commission, upon its request and in 3 years in connection with the review of Big Rivers' financial operations, a copy of any reports, recommendations or other documents produced by the Coordinating Committee or either Smelter, and that is provided to the Big Rivers Board of Directors. To date there is only one such document. This document is attached to my testimony as Exhibit Blackburn-3.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 18?

A. Yes. This item required Big Rivers to advise the Commission, in connection with the review of its financial operations in 3 years of any material changes in its collective bargaining agreements with labor unions. In the "May 5, 2009, Report on Status of Closing the Unwind Transaction" filed in the Unwind Proceeding, Big Rivers informed the Commission: "Big Rivers and IBEW Local 1701, representing the Big Rivers generation division, concluded negotiations on April 16, 2009, regarding the terms of the post-closing collective bargaining agreement between the parties. The proposed contract was approved by the union membership on May 1, 2009." Since that date, there have been no material changes to that collective bargaining agreement. The generation employee collective bargaining agreement was effective July 17, 2009, and terminates on September 14, 2012. The transmission employee collective bargaining agreement term is from October 15, 2008, through October 14, 2012.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 19?

A. Yes. This item required Big Rivers to advise the Commission and the Attorney General's Office of any material changes in the evidences of indebtedness that comprise its financing arrangements, on a timely basis. Big Rivers filed an application in Case No. 2009-00441, *In the Matter of: The Application of Big Rivers Electric Corporation For Approval To Issue Evidences Of Indebtedness* on November 13, 2009. Big Rivers also provided a copy of the application to the Attorney General's Office. The Commission approved that application on March 31, 2010.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 20?

A. Yes. This item required Big Rivers to advise the Commission of any material changes to the smelter-related retail and wholesale contracts, on a timely basis. To date there have been no such material changes.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 21?

A. Yes. This item required Big Rivers to timely advise the Commission and the Attorney General's office in the event of any material changes in its agreements with Henderson

Municipal Power & Light after the closing of the Unwind Transaction. To date there have been no such material changes.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 22?

A. Satisfaction of this requirement is in progress. This item required Big Rivers to complete construction of the transmission system additions and improvements for which the Commission issued a Certificate of Public Convenience and Necessity in Case No. 2007-00177, and to advise the Commission and the Attorney General's Office on a timely basis of the date those transmission facilities become fully operational and of any material events related to the Big Rivers transmission system that impact Big Rivers' long-term ability to wheel excess power to its border for sale into other markets. Big Rivers is continuing the construction of the facilities noted in the requirement. Additional details on the status of the projects are provided in the Direct Testimony of Mr. David G. Crockett. There have been no material events that impact Big Rivers' long-term ability to transmit excess power to its border for sale into other markets.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 23?

A. Yes. This item required that Big Rivers' chief executive officer and relevant members of its senior staff will meet informally with the Commission and the Attorney General's Office at least annually to advise them regarding: (i) general operations and finances of Big Rivers; (ii) transition activities; (iii) regulatory and industry developments that may affect Big Rivers in the future; (iv) the status of Big Rivers' plans for addressing the $200 million reduction in the Maximum Allowed Balance in the RUS Series A Note, before the end of 2015; (v) changes in the competitiveness of the Smelters which could materially affect the commitment of the Smelters to continue operations; and (vi) the work of the Coordinating Committee. An informal meeting was held on March 24, 2010, at the Commission's office which included representatives of the Attorney General's Office, the Smelters, Big Rivers' chief executive officer, relevant members of its senior management, and others. The required update was provided at that meeting.

Q. Has Big Rivers satisfied the requirement in Appendix A Item 24?

A. Yes. This item required that a Rural Economic Reserve account be established and funded at closing of the Unwind Transaction in an amount no less than $60.9 million to be used exclusively to credit the bills rendered to the Rural Customers over a period of 24 months commencing upon depletion of all funds in Economic Reserve. All funds in the Rural Economic Reserve were to be invested in interest-bearing United States Treasury notes, with all interest earned credited to the Rural Economic Reserve. Big Rivers committed that no funds in the Rural Economic Reserve escrow account would be spent, pledged, or otherwise used for any purpose other than as credits on the future bills of Rural Customers in accord with the terms of this commitment. Big Rivers has satisfied this commitment by establishing the Rural Economic Reserve account, funding it as required, and reserving it for the purpose noted herein.

VI. COMMITMENTS IN THE MIDWEST ISO ORDER

Q Is Big Rivers subject to commitments in the Midwest ISO Order?

A. There are certain commitments or restriction listed in the ordering paragraphs of the Midwest ISO Order. Big Rivers is in full compliance with those commitments or restrictions. A "Stipulation and Agreement" was also entered into in connection with the Midwest ISO Order among Big Rivers, Midwest ISO, Kentucky Industrial Utility Customers, Inc. and the Attorney General of Kentucky. Paragraph 2 of that Stipulation and Agreement, which was approved by the Commission, and paragraph 3 of the Stipulation and Agreement, which is a contractual agreement among the parties, related to rate commitments.

Big Rivers committed as follows in paragraphs 2 and 3 of the Stipulation and Agreement:

> 2. Big Rivers' application in this proceeding does not seek authorization from the Commission to recover any Midwest ISO administrative costs or Federal Energy Regulatory Commission ("FERC") fees, for which it becomes obligated (currently charged under Schedules 10, 16 and 17 to the Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Midwest ISO Tariff")), through the Non-FAC Purchased Power Adjustment mechanisms in its wholesale power supply contracts.
>
> 3. Big Rivers will not attempt to recover any Midwest ISO administrative costs or FERC fees, for which it becomes obligated (currently charged under Schedules 10, 16 and 17 to the Midwest ISO Tariff), through the Non-FAC Purchased Power Adjustment mechanisms in its wholesale power supply contracts.

The Application of Big Rivers in this proceeding is made consistent with these commitments.

VII. HISTORY OF BIG RIVERS' RATES

Q. Please describe Big Rivers' rural rates from an historical perspective.

A. Big Rivers' rural rates historically have been relatively low. Attached as Exhibit Blackburn-4, I provide a listing of Big Rivers' historical rural wholesale rates for the period 1994 through 2009. The exhibit shows that Big Rivers' rates were reduced in 1998 to approximately $36.72/MWh as a result of the 1998 lease transaction, and have remained relatively consistent in the range of $35/MWh to $37/MWh since 2001.

Q. During the Unwind Proceeding, did Big Rivers contemplate the need for a general rate case within the 2011-2012 time frame?

A. No. However, after the Unwind Proceeding hearing in December 2008, the current recession continued to weaken the economy and severely impacted the wholesale market for power. As I noted previously, Appendix A Item 12 of the Unwind Order required Big Rivers to file, within 3 years of closing the Unwind Transaction, a general review of its financial operations and its tariffs. Since then, Big Rivers has continued to advise the Commission in its New Financial Model filings that a base rate increase was projected for the current timeframe.

VIII. SUMMARY OF SMELTER SERVICE AGREEMENTS

Q. Did Big Rivers and Kenergy enter into new wholesale and retail agreements related to service to the Smelters in conjunction with the Unwind Transaction?

A. Yes. Big Rivers and Kenergy negotiated new wholesale and retail agreements related to service to the Smelters in order to provide the Smelters power at competitive prices while simultaneously providing protections to Big Rivers and its non-Smelter customers against the risks inherent in resuming the role of power supplier to the Smelters.

Q. Please describe the Service Agreements in place between Big Rivers and the Smelters.

A. The Service Agreements provide that Big Rivers will supply 368 MW to Alcan and 482 MW to Century upon payment of the following amounts:

1. A base energy rate of $0.25 per MWh above Big Rivers' wholesale power rate to its members for resale to dedicated delivery point large industrial customers (subject to future adjustment by the Commission) adjusted for a 98-percent load factor;
2. A Fuel Adjustment Clause ("FAC") charge;
3. An Environmental Surcharge;
4. A Times Interest Earned Ratio ("TIER") Adjustment Charge through 2023, starting with up to a maximum of $14.2 million annually in 2009 and increasing to $34.7 million annually in 2021, to assist Big Rivers in its efforts to maintain a Contract TIER of 1.24;

5. A Non-FAC purchase power adjustment charge; and

6. Surcharges consisting of:

   a. Surcharge One - a fixed rate of \$0.70 per MWh in 2009-2011, \$1.00 per MWh in 2012-2016, and \$1.40 per MWh in 2017-2023; and

   b. Surcharge Two - a fixed rate of \$0.60 per MWh each year, subject to a \$200,000 monthly credit for the first 96 months; plus an additional rate of \$0.60 per MWh contingent on actual fuel costs exceeding a base line.

The Smelters are also entitled to an Equity Credit, to be paid by Big Rivers in any year that it earns a Contract TIER in excess of 1.24 and does not elect to make a credit of the excess TIER to all customers.

Q. Is Big Rivers proposing to alter the Smelter Service Agreements in this filing?

A. No. Big Rivers is not proposing to alter the Smelter Service Agreements in this proceeding. It is important to note, however, that the Smelter Service Agreements utilize the Large Industrial Customer Rate in determining the Smelters' base energy charge. Big Rivers is proposing to increase the Large Industrial Customer Rate in this filing. Thus, while the Smelter Service Agreements do not change, the Smelters will experience a rate increase under the proposed rates.

Q. Do the Smelter Service Agreements provide for credits against the Smelters rate obligations?

A. Yes. Section 4.13 of the Service Agreements provides the Smelters credits for Surplus Sales, Undeliverable Energy Sales, Potline Reduction Sales, Curtailment of Purchase Power, Economic Sales and other amounts. This section was included in the contract to assist the Smelters during periods of time when a Smelter chooses to reduce its Base

Demand per Hour for electricity and off-set the Smelters' responsibility for the related fixed cost by the Net Proceeds made available from sales.

Q. What options in the Smelter Agreements have the Smelters utilized to reduce their cost of power and how much, in dollars, have the Smelters' costs for power been reduced by credits from these provisions?

A. Sections 4.13.1 and 4.13.2 of the Smelter Agreements provide for credits to the Smelters' invoices for Surplus Sales and Curtailment of Purchased Power, respectively. In the case of Surplus Sales the Smelters may elect under Section 10.1 of the Smelter Agreements for Big Rivers to attempt to sell any power that is in excess of their needs. Curtailment of Purchased Power involves Big Rivers and the Smelter(s) agreeing to the duration and amount of their Base Demand per Hour to be curtailed and compensated at a Market Reference Rate. From July 2009 through January 2011, the Smelters' cost for power has been reduced as follows:

Century	$36,218,360
Alcan	$ 6,908,349
Smelter Total	$43,126,709

Q. Are there other options available to the Smelters to reduce their cost of power that were not exercised during the test year?

A. Yes. Undeliverable Energy Sales, Potline Reduction Sales, Economic Sales and Market Energy Sales provide other mechanisms for the Smelters to reduce the cost of their power. However, as of January 2011 the Smelters have not made use of these options in the Smelter Agreements.

Q. Do the Smelter Service Agreements provide for termination of service?

A. Yes. The Service Agreements provide that, under a worst-case scenario, the Smelters have the right to permanently close their operations, but only upon one year's advance notice. The potential for this outcome was discussed at length in the Unwind Proceeding, and I discuss Big Rivers' plans for handling such a scenario in the section that follows.

IX. <u>RISK MANAGEMENT FOR SMELTER LOSS</u>

Q. During the Unwind Proceeding, did parties to the case raise concerns about the possibility that the Smelters may close?

A. Yes. The Office of the Attorney General expressed concern that the Smelters may close and urged the Commission to review the proposed transaction with an abundance of caution. The Commission recognized this concern on page 18 of the Unwind Order:

> While the Commission cannot predict the future economic viability of the Smelters, the power prices set forth in the new service agreements should provide a reasonable opportunity for the Smelters to continue operating in Kentucky for the long term and to preserve the jobs and tax base which support the economy of western Kentucky.

Q. Have other entities raised concerns about the possibility that the Smelters may close?

A. Yes. Fitch Ratings, Moody's Investor Service and Standard & Poor's have noted in recent credit reviews of Big Rivers that Big Rivers relies on the Smelters for a majority of its overall energy sales, and that this reliance on sales to customers that are so vulnerable to economic cycles is a credit weakness and/or a risk that cannot be ignored.

Q. Does Big Rivers share this concern?

A. Yes, for several reasons. As a business, Big Rivers desires a strong working relationship with each of the Smelters and that the Smelters remain viable for the mutual benefit of the Smelters, Big Rivers, and Big Rivers' Members. Of equal importance, as a corporate citizen Big Rivers supports the present and future viability of the Smelters for the benefit of their employees, other supporting local businesses, the local community at large, and the regional economic welfare of all of western Kentucky.

So when Big Rivers proposes an increase in rates that will affect the Smelters, we are concerned about the effect it will have on them as well as on other customers. The Smelter Service Agreements recognize the uncertainty in the aluminum commodity industry. That is why the contracts allow a Smelter to exit its electric service agreement on one year's notice. But we also recognize that one-third of the Big Rivers system load cannot support the commercial viability of two large industrials that comprise the remaining two-thirds of the system load. Big Rivers' view is that the best it can do is to operate in a prudent manner at the lowest reasonable cost consistent with good utility practice, while preparing for the possibility that one or both Smelters may one day decide to abandon their Kentucky operations.

Q. Has Big Rivers determined steps or actions to address the potential loss of one or both Smelters?

A. Yes. During the Unwind Transaction discussions, Big Rivers outlined the steps it would take to deal with the loss of one or both Smelters.

Q. Please review the steps or actions for Big Rivers in the event that one or both Smelters cease operations and terminate their contracts.

A. First, as previously discussed, Big Rivers established at the Unwind Transaction closing a $35 million transition reserve account. The funds in this account will be available to offset any temporary reduction in cash flow that could occur if one or both Smelters cease operations and terminate their contracts.

Second, transmission construction projects were planned in two phases. Phase 1 of Big Rivers' internal transmission upgrades has been completed and would allow Big Rivers to transmit to its border all additional energy which would have been consumed by one Smelter. Big Rivers has nearly completed its Phase 2 transmission projects, which will allow Big Rivers to transmit to its border all additional energy which would have been consumed by both Smelters. A complete listing of all Phase 2 transmission projects and their completion status is provided in the Direct Testimony of Mr. David G. Crockett. Because the Smelter Service Agreements require one year's notice for termination, Big Rivers will be able to complete the Phase 2 transmission projects in time for them to be available if needed. Additionally, Vectren is in the process of building a 345 kV interconnection with Big Rivers which will enhance Big Rivers' ability to import/export power when completed (Kentucky State Board on Electric Generation and Transmission Siting, Case No. 2010-00223).

Third, Big Rivers has retained its transmission reservation and rights for 100 MWs of power to be wheeled across the Tennessee Valley Authority's ("TVA") transmission system to the Southern Company transmission interface with TVA.

Fourth, the Kentucky General Assembly, at Big Rivers' urging, amended KRS 279.120 in 2006. The amendment enables a cooperative like Big Rivers that finds itself with a sudden, large drop in system load to remarket that power to non-members without endangering its cooperative status under state law. If one or both of the Smelters were to terminate service, Big Rivers believes it has easier access to loads located in the footprint of the Midwest ISO, and thus would have increased options to market its generation. Big Rivers joined the Midwest ISO solely to comply with NERC criteria for Contingency Reserves, but this access to markets is a collateral benefit. Big Rivers is also aware of other utilities in its region that need to add base load resources. Recently, Big Rivers was approached by a municipality that expressed an interest in having discussions with Big Rivers for a long-term power supply.

Thus, Big Rivers could take the steps outlined above to address the termination of one or both of the Smelter Service Agreements, should such an unfortunate possibility be realized. While no one can predict the future, it is important to note that on February 10, 2010, Alcan announced a $37 million improvement to its Sebree complex, and Century is restarting it fifth potline this month.

X. <u>PRO FORMA ADJUSTMENTS</u>

Q. Are you sponsoring any pro forma adjustments to test year expenses?

A. Yes. I am supporting a pro forma adjustment to reflect prospective levels of Outside / Professional Services and a pro forma adjustment to reflect Big Rivers' commitment to implement Energy Efficiency Programs, as noted in the Direct Testimony of Mr. John Wolfram (Exhibit 51), in Exhibit Wolfram-2, Reference Schedules 2.25 and 2.26.

A. OUTSIDE / PROFESSIONAL SERVICES

Q. Please explain the adjustment to operating expenses shown in the Reference Schedule 2.25 of Exhibit Wolfram-2, for Outside / Professional Services.

A. This adjustment eliminates expenses associated with outside / professional services that were incurred in the test year that exceed the level of expenses anticipated for these services on a going-forward basis. During the test year, Big Rivers incurred approximately $2.7 million for outside / professional services associated with numerous corporate matters, including the development of the 2010 Integrated Resource Plan, GAAP auditors, income tax advisors, state regulatory reviews of FAC and ES filings, focused internal audits, and Human Resources matters.

The $2.7 million amount does not include the test year expenses associated with development of this rate case or with the Midwest ISO proceedings at the Commission and at FERC. These two items are considered in other proposed pro forma adjustments noted in the Direct Testimony of Mr. Wolfram, Exhibit Wolfram-2, in Reference Schedules 2.13 and 2.21 respectively. Both adjustments are described further by Mr. Hite in his Direct Testimony.

Q. Is the exact level of annual expenses for outside / professional services certain on a prospective basis?

A. No. Certain services incurred in the test year relate to matters that do not occur every year. Other services may or may not be needed each year. In future years, there are likely to be other matters that did not take place in the test year, but for which Big

Rivers requires outside / professional assistance. Thus the exact amount of expenses on a going-forward basis is not certain.

Q. Is it possible for Big Rivers to determine a meaningful, historically "normal" level for these expenses?

A. No. Since the Unwind Closing took place in July 2009, Big Rivers does not have historical data for expenses that reflect the conditions under which Big Rivers operates today. In other words, the pre-Unwind expenses are not comparable to the post-Unwind expenses for outside / professional services.

Q. Why is Big Rivers proposing to reduce the test year level of outside / professional service expense?

A. Big Rivers believes that an adjustment to the test year level of expenses for outside / professional services is reasonable. In my professional judgment, a reduction of $1 million is appropriate.

B. ENERGY EFFICIENCY

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.26 of Exhibit Wolfram-2, for Energy Efficiency.

A. This adjustment reflects the commitment of Big Rivers to implement Energy Efficiency and Demand-Side Management ("DSM") Programs, as outlined in the Big Rivers 2010 Integrated Resource Plan.

Q. Please describe the commitment that Big Rivers is prepared to make regarding Energy Efficiency and DSM Programs.

A. Contingent upon the acceptance of this pro forma adjustment to test year expenses and its inclusion in base rates, Big Rivers commits that it will spend $1 million annually on the Energy Efficiency and DSM programs as proposed in the 2010 Integrated Resource

Plan, and/or any subsequent program filings, to create and promote incentives for a number of consumer energy efficiency measures.

Q. What does Big Rivers project to spend on Energy Efficiency and DSM Programs in the next few years?

A. Big Rivers has budgeted to spend $544,000 in 2011, when the programs will be launched. Big Rivers expects that level to rise to approximately $1.1 million in 2012 when the program ramp-up is complete. The annual spend will remain at that level for 2013.

Q. Is Big Rivers proposing at this time to implement a cost recovery mechanism for DSM Programs pursuant to KRS 278.285?

A. No. Big Rivers is proposing to include $1 million of Energy Efficiency and DSM program-related expenses in base rates in this proceeding. While Big Rivers may elect to seek the establishment of a mechanism for recovering the full costs of programs in the future, pursuant to KRS 278.285(2), it does not anticipate doing so in the near term.

Q. Has Big Rivers incurred significant expenditures for Energy Efficiency or DSM Programs in recent years?

A. No. Big Rivers has not spent significant amounts for Energy Efficiency or DSM programs recently. After the closing of the Unwind, Big Rivers needed to study the costs and benefits of potential offerings, which it did and provided in the 2010 IRP. Furthermore, during the test year, Big Rivers did not have sufficient funds to support any substantial programs and still meet its debt covenant TIER requirements.

Q. Why is Big Rivers proposing this pro forma adjustment at this time?

A. Big Rivers believes that providing cost-effective Energy Efficiency offerings to our Members is a high priority and proposes to include this pro forma adjustment at this time to better enable Big Rivers to implement these programs. The focus at this time is on quickly and effectively establishing the programs that were outlined in the 2010 IRP, consistent with the outcome of the 2010 IRP proceeding.

XI. CONCLUSION

Q. Please summarize your testimony.

A. Since the close of the Unwind Transaction, Big Rivers has satisfied all of the applicable commitments noted by the Commission in the Unwind Order. Both of the New Financial Models filed since the Unwind Transaction indicated that a base rate increase greater than 11% for members was presumed to be effective in 2012; the instant filing is generally consistent with the projections included in both the October 2009 and April 2010 New Financial Model filings.

Big Rivers' rates have historically been relatively low. I completely understand that increasing electric rates is always difficult for customers. However, Big Rivers has deferred costs as much as possible and now must increase rates to allow it to perform necessary maintenance and meet its debt covenants. Proper and timely maintenance of Big Rivers' generating plants is important not only to assure that electricity is available to serve Big Rivers' members, but also for the off-system market sales that furnish Big Rivers' margins. Big Rivers is contractually obligated to comply with its debt covenants. In this proceeding Big Rivers has proposed base rates that will allow its Members to remain competitive with other utilities in Kentucky, and will be extremely competitive with other utilities nationwide.

Big Rivers has Service Agreements in place with the Smelters that were approved in the Unwind Transaction. Big Rivers is not proposing to alter those agreements in this proceeding. Big Rivers recognizes the risk associated with the loss of the Smelters and has a sound plan in place for this contingency.

Q. Do you have any closing comments?

A. Yes. Big Rivers does not take the decision to seek this increase lightly. Base rate increases are simply necessary at this time in order for Big Rivers to adequately recover its costs and to meet its existing debt covenants with its creditors. The rates proposed herein are fair, just and reasonable and should be approved by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

Big Rivers Electric Corporation
Case No. 2011-00036

Excerpts from: Indenture Dated as of July 1, 2009, between Big Rivers Electric Corporation and U.S. Bank National Association, Trustee

Section 1.1 Definitions.

"**Available Margins Certificate**" means an Officers' Certificate, dated not more than thirty (30) days prior to the date of the related Application, and signed by a Person who is an Accountant (who may be one of the two signing Officers), stating that:

A. the Margins for Interest Ratio is not less than 1.10 for one of the following periods of time: (i) the fiscal year of the Company immediately preceding the fiscal year in which the Application is made, or (ii) if the Application is made within ninety (90) days after the end of a fiscal year, the second preceding fiscal year of the Company or (iii) any twelve (12) consecutive calendar months during the period of fifteen (15) calendar months immediately preceding the first day of the calendar month in which the Application is made **PROVIDED, HOWEVER**, that if any such period of time is one in which this Indenture has not been in effect for the full period of time, then, in lieu of a statement as to the Margins for Interest Ratio, such Available Margins Certificate shall state that the Times Interest Earned Ratio (as defined in the Existing Mortgage) is not less than 1.05 for such period of time; and

B. the Margins for Interest Ratio has been calculated in accordance with the definitions contained in this Indenture **PROVIDED, HOWEVER**, that if the Available Margins Certificate makes a statement as to the Times Interest Earned Ratio and not the Margins for Interest Ratio, stating that the Times Interest Earned Ratio has been calculated in accordance with the provisions of the Existing Mortgage.

If any period of twelve (12) months referred to in an Available Margins Certificate has been a period with respect to which an annual report is required to be filed by the Company pursuant to Section 10.4, such Certificate shall be accompanied by a report of an Independent Accountant stating in substance that nothing came to the attention of such Accountant in connection with the audit of such period that would lead such Accountant to believe that there was any incorrect or inaccurate statement in such Available Margins Certificate; **PROVIDED, HOWEVER,** that if the Application is made prior to the date on which an annual report is required to be filed by the Company pursuant to Section 10.4, such Certificate shall not be accompanied by such Independent Accountant's report. Each such report of an Independent Accountant shall include the statement as to independence required by the definition of the term "Independent."

"**Interest Charges**" for any period means the total interest charges (whether capitalized or expensed) for such period (determined in accordance with Accounting Requirements) related to (i) Outstanding Secured Obligations of the Company, or (ii) outstanding Prior Lien Obligations of the Company, in all cases including amortization of debt discount and premium

Excerpts from: Indenture Dated as of July 1, 2009, between Big Rivers Electric Corporation and U.S. Bank National Association, Trustee

on issuance, but excluding all interest charges related to Obligations that have actually been paid by another Person that has agreed to be primarily liable for such Obligation pursuant to an assumption agreement or similar undertaking, provided such assumption agreement or similar undertaking is not a mechanism by which the Company continues to make payments to such Person based on payments made by such Person on account of its assumed liability or by which the Company otherwise seeks to avoid having interest related to such Obligations included in the definition of Interest Charges without the economic substance of an assumption of liability on the part of such Person; **PROVIDED, HOWEVER,** that with respect to any calculation of Interest Charges for any period prior to the date hereof, "Interest Charges" means the total interest charges (whether capitalized or expensed of the Company for such period (determined in accordance with Accounting Requirements) with respect to interest related to indebtedness the obligation for the payment of which was secured under the Existing Mortgage or by a lien against property subject to the Existing Mortgage prior to or on a parity with the lien of the Existing Mortgage, other than "Permitted Encumbrances" (as defined in the Existing Mortgage), in all cases including amortization of debt discount and premium on issuance.

. . .

"**Margins for Interest**" means, for any period, the sum of (i) net margins of the Company for such period (which, except as otherwise provided in this definition, shall be determined in accordance with Accounting Requirements), which shall include revenues of the Company, subject to possible refund at a future date, but which shall exclude provisions for any (a) non-recurring charge to income, whether or not recorded as such on the Company's books, of whatever kind or nature (including the non-recoverability of assets or expenses), except to the extent the Board of Directors determines to recover such non-recurring charge in Rates, (b) refund of revenues collected or accrued by the Company in any prior year subject to possible refund; plus (ii) the amount, if any, included in the computation of net margins for accruals for federal and state income and other taxes imposed on income after deduction of interest expense for such period; plus (iii) the amount, if any, included in the computation of net margins for any losses incurred by any Subsidiary or Affiliate of the Company; plus (iv) the amount, if any, the Company actually receives in such period as a dividend or other distribution of earnings or profits of any Subsidiary or Affiliate (whether or not such earnings were for such period or any earlier period or periods); minus (vi) the amount, if any, included in the computation of net margins for any earnings or profits of any Subsidiary or Affiliate of the Company; and minus (vi) the amount, if any, the Company actually contributes to the capital of, or actually pays under a guarantee by the Company of an obligation of, any Subsidiary or Affiliate in such period to the extent of any accumulated losses incurred by such Subsidiary or Affiliate (whether or not such losses were for such period or any earlier period or periods), but only to the extent such losses have not otherwise caused other contributions or guarantee payments to be included in net

Excerpts from: Indenture Dated as of July 1, 2009, between Big Rivers Electric Corporation and U.S. Bank National Association, Trustee

margins for purposes of computing Margins for Interest for a prior period and such amount has not otherwise been included in net margins.

"**Margins for Interest Ratio**" means, for any period, (i) the sum of (a) Margins For Interest plus (b) Interest Charges, divided by (ii) Interest Charges.

Section 8.1 Events of Default.

"**Event of Default**" means, wherever used herein, any one of the following events (whatever the reason for such event and whether it shall be voluntary or involuntary or be effected by operation of law or pursuant to any judgment, decree or order of any court or any order, rule or regulation of any administrative or governmental body).

. . .

C. default in the performance, or breach, of any covenant or warranty of the Company in this Indenture (other than a covenant or warranty a default in the performance or breach of which is described in paragraph A or B of this Section), and continuance of such default or breach for a period of thirty (30) days after there has been given, by registered or certified mail, to the Company by the Trustee, or to the Company and the Trustee by the Holders of not less than 25% in principal amount of the Obligations Outstanding, a written notice specifying such default or breach and requiring it to be remedied and stating that such notice is a "Notice of Default" hereunder, unless such default cannot be reasonably cured within such thirty (30) day period then, so long as a cure is being diligently pursued, the Company shall have a reasonable period of time beyond such thirty (30) day period to complete such cure.

Section 13.1 Payment of Principal, Premium and Interest.

The Company will duly and punctually pay the principal of (and premium, if any) and interest on the Obligations in accordance with the terms of the Obligations and this Indenture.

Section 13.7 Maintenance of Properties.

The Company will cause all its properties used or useful in the conduct of its business to be maintained and kept in good condition, repair and working order and supplied with all necessary equipment and will cause to be made all necessary repairs, renewals, replacements, betterments and improvements thereof, all as in the judgment of the Company may be necessary so that the business carried on in connection therewith may be properly and advantageously conducted at all times; **PROVIDED, HOWEVER,** that nothing in this Section shall prevent the

Company from discontinuing the operation and maintenance of any of its properties if such discontinuance is, in the judgment of the Company, desirable in the conduct of its business and not disadvantageous in any material respect to the Holders.

The Company will promptly classify, and record on its books, as retired, all property that has permanently ceased to be used or useful in the business of the Company.

Section 13.12 Statement as to Compliance.

The Company will deliver to the Trustee, within one hundred and twenty (120) days after the end of each calendar year beginning with the year 2010, a written statement signed by the principal executive officer and by the principal financial officer or principal accounting officer of the Company stating that a review of the Company's activities during the preceding calendar year has been made under their supervision and that the Company has fulfilled its obligations hereunder in all material respects during such calendar year.

Promptly after any Officer of the Company may reasonably be deemed to have knowledge of a default hereunder, the Company will deliver to the Trustee a written notice specifying the nature and period of existence thereof and the action the Company is taking and proposes to take with respect thereto.

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.

Excerpts from: Amended and Consolidated Loan Contract dated as of July 16, 2009, between Big Rivers Electric Corporation and United States of America

Section 4.2 Performance under Loan Documents

The Borrower shall duly observe and perform all of its obligations under each of the Loan Documents.

Section 4.3 Annual Certification

Within ninety (90) days after the close of each fiscal year (or, if the Borrower has delivered written notice to the RUS prior to the expiration of such ninety (90) day period that the Borrower has determined in good faith that an additional thirty (30) days for such delivery is necessary or advisable, then within one hundred twenty (120) days after the close of the fiscal year with respect to which such notice has been delivered), the Borrower shall deliver to the RUS a written statement signed by its General Manager, stating that during such year the Borrower has fulfilled its obligations under the Loan Documents throughout such year in all material respects or, if there has been a material default in the fulfillment of such obligations, specifying each such default known to the General Manager and the nature and status thereof.

Section 4.4 Rates and Margins for Interest Ratios

(a) *Prospective Requirement*. The Borrower shall design and implement rates for utility service furnished by it to maintain, on an annual basis, the Margins for Interest Ratio specified in Section 13.14 of the Indenture.

(b) *Prospective Notice of Change in Rates*. The Borrower shall give the RUS sixty (60) days' written notice prior to the effective date of any proposed change in the Borrower's general rate structure.

(c) *Routine Reporting of Margins for Interest Ratio*. The Borrower shall report to the RUS, no later than 45 days after December 31 of each year, in such written format as the RUS may require, the Margins for Interest Ratio that was achieved during the preceding 12-month period ending on December 31 of such year.

Excerpts from: Indenture Dated as of July 1, 2009, between Big Rivers Electric Corporation and U.S. Bank National Association, Trustee

(d) *Reporting Non-achievement of Retrospective Requirement.* If the Borrower fails to achieve the Margins for Interest Ratio specified in Section 13.14 of the Indenture for any fiscal year, it must promptly notify RUS in writing to that effect.

(e) *Corrective Plans.* Within thirty (30) days of (i) sending a notice to the RUS under paragraph (d) above that shows the Margins for Interest Ratio specified by Section 13.14 of the Indenture was not achieved for any fiscal year, or (ii) being notified by the RUS that the Margins for Interest Ratio specified by Section 13.14 of the Indenture was not achieved for any fiscal year, whichever is earlier, the Borrower in consultation with the RUS shall provide a written plan satisfactory to the RUS setting forth the actions that shall be taken to achieve the specified Margins for Interest Ratio on a timely basis.

(f) *Noncompliance.* Failure to design and implement rates pursuant to paragraph (a) of this section and failure to develop and implement the plan in accordance with the terms of paragraph (e) of this section shall constitute an Event of Default under this Agreement in the event that RUS so notifies the Borrower to that effect under Section 6.1(d) of this Agreement.

Section 4.23 Maintenance of Credit Ratings

(a) *Maintenance of Credit Ratings.* As long as there remains any RUS Note, the Borrower shall (i) maintain a Credit Rating from at least two Rating Agencies and (ii) continuously subscribe with a Rating Agency for the services described in Exhibit C attached hereto.

(b) *Reporting Non-achievement of Investment Grade Credit Rating.* If the Borrower fails to maintain two Credit Ratings of Investment Grade, it must notify RUS in writing to that effect with five (5) days after becoming aware of such failure.

(c) *Corrective Plans.* Within thirty (30) days of the date on which the Borrower fails to maintain two Credit Ratings of Investment Grade, the Borrower in consultation with the RUS shall provide a written plan satisfactory to the RUS setting forth the actions that shall be taken that are reasonably expected to achieve two Credit Ratings of Investment Grade.

(d) *Noncompliance.* Failure to implement a corrective plan developed in accordance with paragraph (c) of this section shall constitute an Event of Default under this Agreement.

Big Rivers Electric Corporation
Case No. 2011-00036

Calculation of MFIR for Test Year

Margins	$	11,717,454
Interest		47,693,118
Income Taxes		885
Total	$	59,411,457
MFIR[1]	=	1.25

[1] 1.25 = 59,411,457 / 47,693,118

Rio Tinto Alcan

Power costs and the U.S. aluminum industry

January 18, 2011

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Exhibit Blackburn-3
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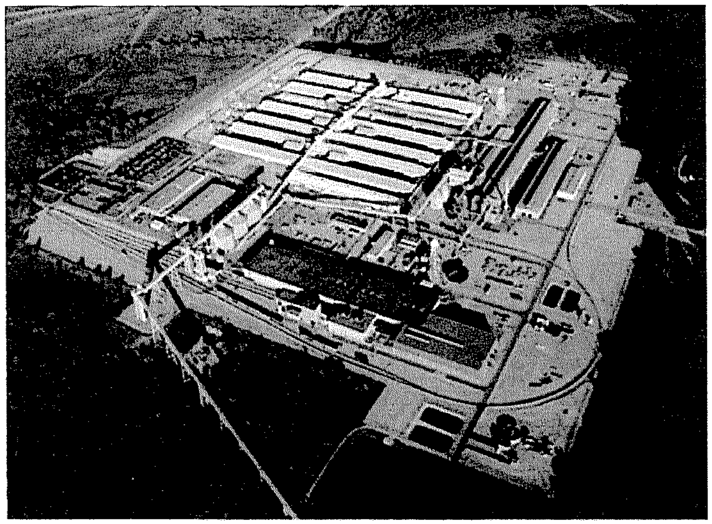
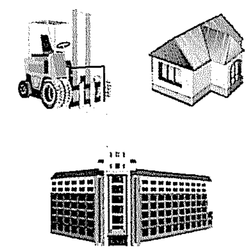
RioTintoAlcan

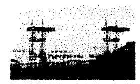
Structure of BREC sales

Smelters represent 70% of Big Rivers load

Smelters	Members	Market
7300 GWh / 850MW	3500 GWh / 350MW	1200 GWh



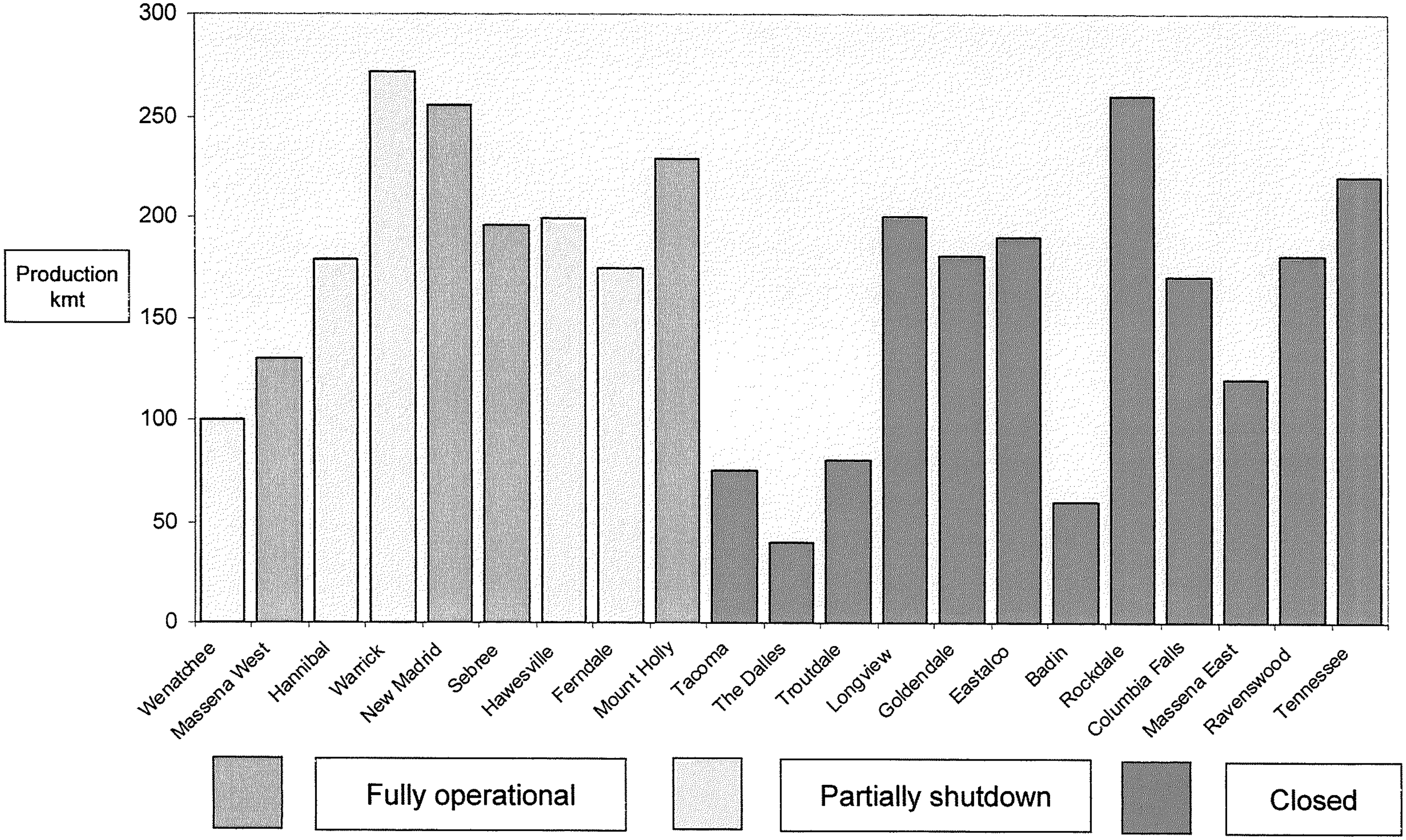




U.S. aluminum industry overview

RioTinto Alcan

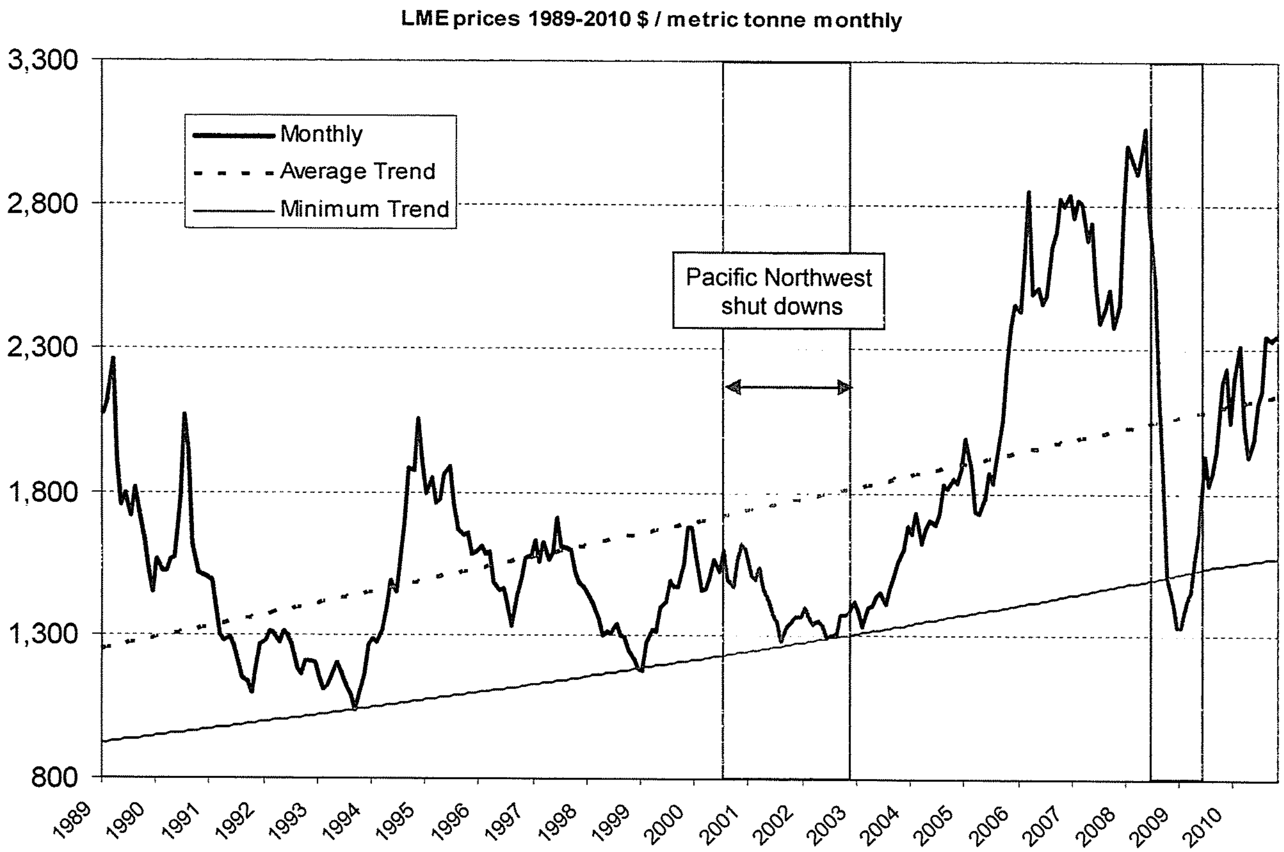
Four facilities currently operational at 100%, five facilities curtailed. At least 12 shut down in last 10 years, mainly in 2000-03 and 2008-09.



Aluminum prices since 1989

RioTinto Alcan

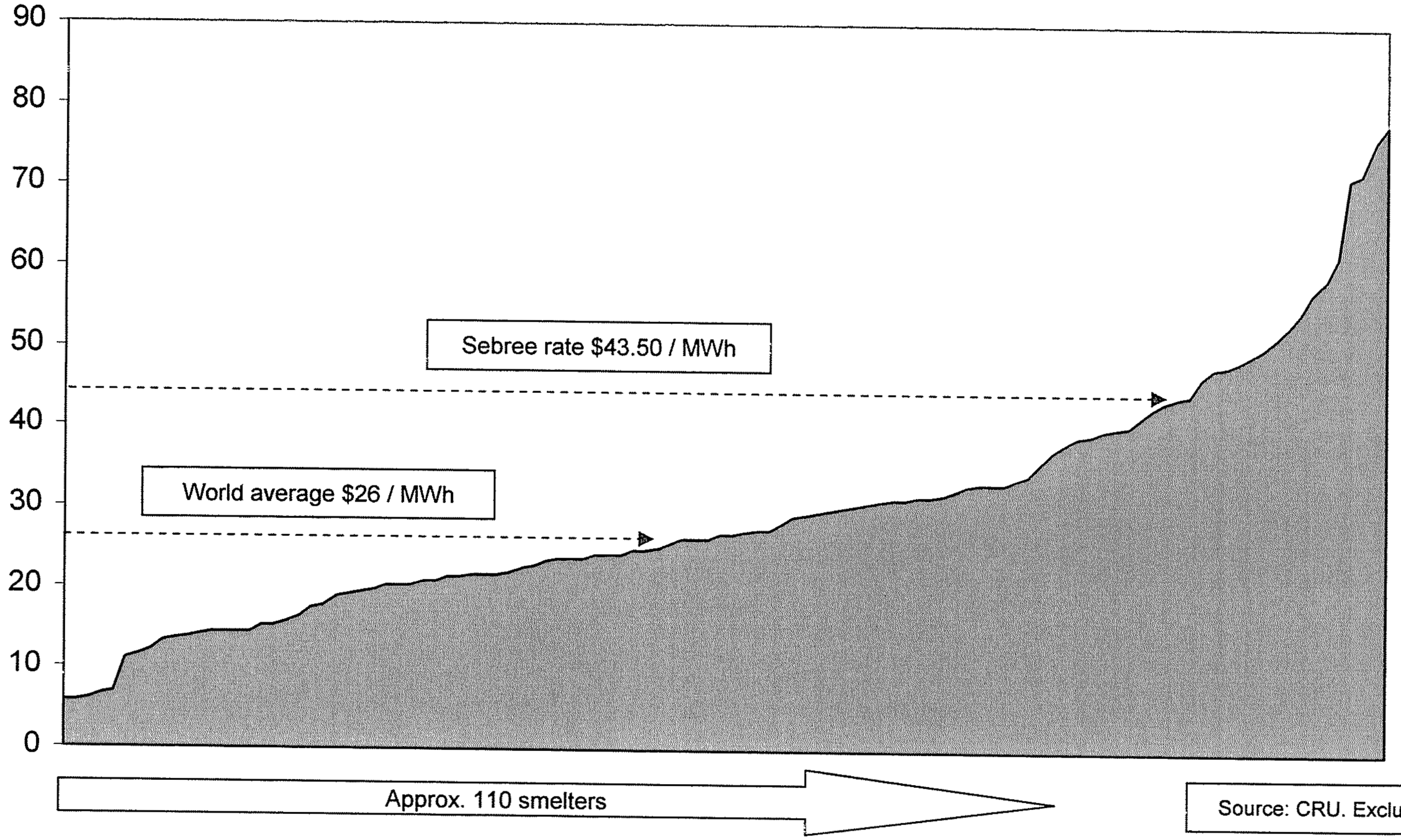
The market for aluminum is highly cyclical.



Worldwide smelter power costs 2010 US$/MWh

RioTintoAlcan

Smelter power cost is $43.50/MWh compared to global average of $26



Source: CRU. Excludes China.

Case No. 2011-00036
Exhibit Blackburn-3
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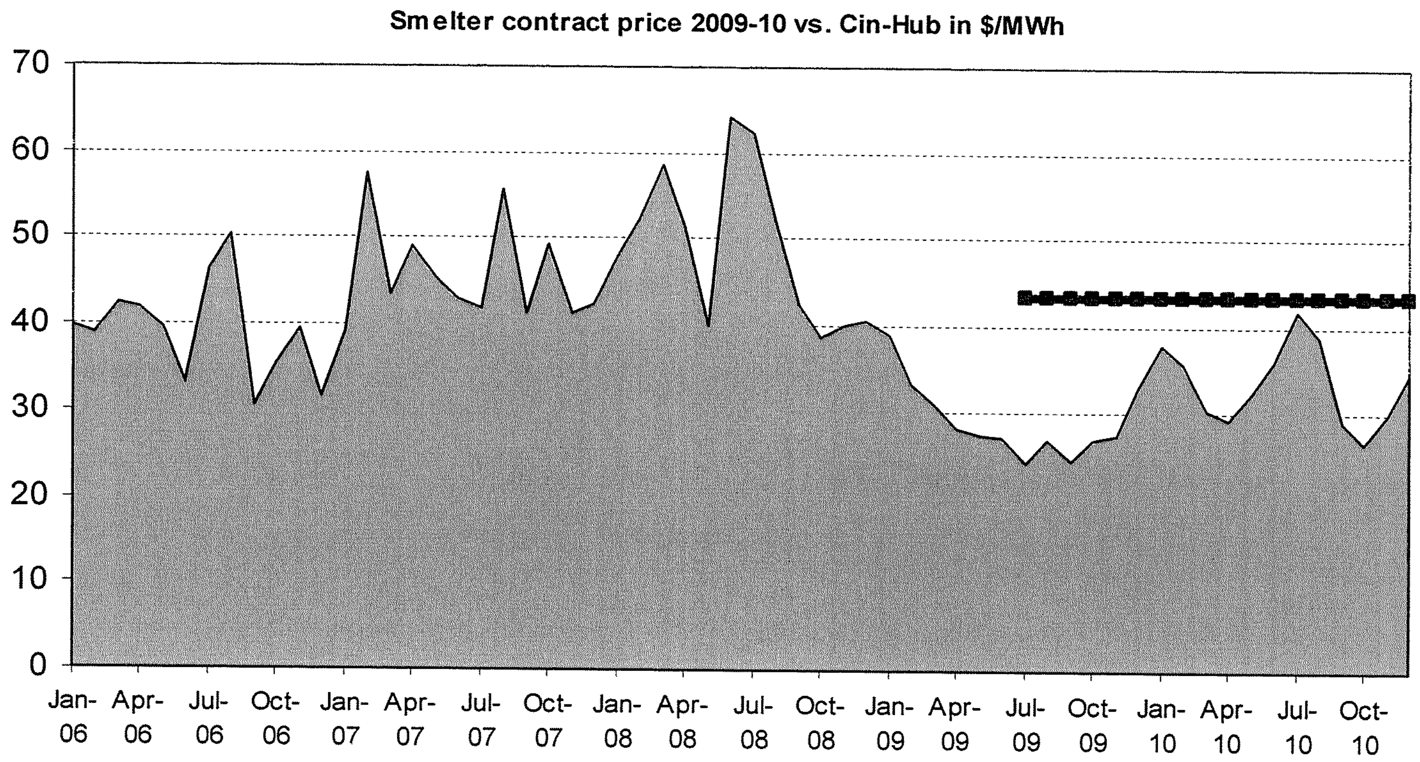
Comparison to market price

RioTinto Alcan

Smelter contract price compared to MISO Cinergy-Gibson hub



Smelter support to Big Rivers

Rio Tinto Alcan

Additional $27m support from Smelter to Big Rivers + Members.
This equates to $7.50/MWh if spread over the Member load.

Margin $0.25 → **$1.8m to Big Rivers**

TIER $1.95 → **$14.2m to Big Rivers**

BREC receives $16m

Surcharge $1.57 → **$11.5m to Members**

Total $3.77

The $27m will increase in future years

Advantages to BREC and members of smelter business

Smelter baseload reduces operating and financial risk to Big Rivers.

- Near-constant 7*24 baseload suitable for coal-fired power.
- Allows a larger generation network to be maintained than would otherwise be the case (increased flexibility and stability with reduced uncertainty).
- Direct pass-through of non-fuel purchased power cost
- Smelter loads can protect against system blackout in extreme conditions (such as 2009 ice storm).
- Contract price is more stable than the power market
- Aids Big Rivers borrowing ability (Big Rivers must borrow from the commercial market, not RUS)

Conclusion

RioTinto Alcan

The success of the Smelters is essential for the financial health and survival of Big Rivers and financial stability of the Members.

- Rio Tinto Alcan smelter at Sebree is a significant contributor to the operational and financial stability of Big Rivers

- Absence of the smelters would result in a major rate increase to the Members
  - Smelters support to Big Rivers of $27m annually reduces Member rates by $7.50 / MWh

- The smelter competes in a global marketplace which is highly cyclical

- Much of the U.S. aluminum industry has closed since the year 2000, due to high power costs
  - most of those still operating have self-generated power or have special contracts or other regulatory treatments that keep costs low or track the LME.

- Sebree has reduced its own cost base by $30m (excluding power) since 2008.

- The coming years will be a significant challenge for the Sebree smelter to remain competitive and avoid closure.

Big Rivers Electric Corporation
Case No. 2011-00036

Actual Historical Rural Wholesale Rate

Year	$/MWh including the effect of the MRSM	MRSM ($/MWh)	$/MWh excluding the effect of the MRSM
1994	45.58		
1995	44.76		
1996	42.72		
1997 [1]	40.17		
1998	36.72		
1999	36.44		
2000 [2]	36.25		
2001	35.27		
2002	35.38		
2003	34.99		
2004	35.06		
2005	35.19		
2006	35.58		
2007	35.22		
2008 [3]	35.90		
2009 [4]	37.00	4.13	41.13
2010 [5]	37.26	7.89	45.15

Note(s):

1. Current base rate effective September 1997.
2. Revenue Discount Adjustment effective September 2001.
3. Revenue Discount Adjustment terminated September 2008.
4. In 2009, the Member Rate Stability Mechanism lowered the effective rate by $4.13/MWh.
5. In 2010, the Member Rate Stability Mechanism lowered the effective rate by $7.89/MWh.

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

DIRECT TESTIMONY

OF

ALAN SPEN
SENIOR DIRECTOR
PUBLIC FINANCIAL MANAGEMENT, INC.

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY

OF

ALAN SPEN

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DIRECT TESTIMONY
OF
ALAN SPEN

I. INTRODUCTION

Q. Please state your name, address and background information on your company.

A. My name is Alan Spen. I am a Senior Director at Public Financial Management, Inc. ("PFM"). The PFM Group was founded in 1975, providing independent financial advisory services to state and local governments. Today, the company is comprised of PFM and PFM Asset Management specializing in financial and investment advisory on a national level. I am part of the firm's Public Power group, which The Bond Buyer/Securities Data Company ranks number one in 2010 in advising public power utilities based upon number of transaction and dollars of financing of public power long-term municipal new issues. My primary responsibilities for PFM relate to our electric cooperative practice. My business address is 24 Hayes Hill Drive, Northport, NY 11768.

Q. Please describe your educational background and relevant experience.

A. I hold a Bachelor of Science in Finance from Florida State University and an MBA from City University of New York. I started my career at Standard & Poor's, working in the corporate and municipal bond rating departments. When I left S&P in 1981, I was in charge of the firm's Public Power group, which was responsible for analyzing and rating rural electric cooperatives.

I subsequently held positions at Lehman Brothers as a municipal investment banker in their Public Power area; was a senior utility analyst at Merrill Lynch and was group manager of Drexel Burnham's municipal finance group. Before joining PFM, I spent approximately 20 years at Fitch Ratings, as head of the firm's municipal revenue bond group, and was also responsible for helping to build the firm's public power and electric cooperative practice. I joined PFM two years ago.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I have been asked by Big Rivers Electric Corporation, a rural electric and generation transmission cooperative ("G&T"), to: (i) summarize current rating agency criteria for G&T cooperatives; (ii) present my view of Big Rivers' strengths and weaknesses from the standpoint of the ratings process; (iii) furnish a list of current credit ratings for the G&T cooperative sector and describe Big Rivers' standing in that group; and (iv) provide an independent opinion on how the credit markets would view Big Rivers' credit, assuming its filed rate adjustment is allowed.

The following testimony addresses those points and summarizes my views regarding the level of financial protection necessary for Big Rivers to maintain investment grade credit ratings. The rating agencies have independent views on credit quality and make their own determination regarding credit ratings. Information that I use for my evaluation of Big Rivers includes public information from the three rating agencies, relevant materials provided to me by Big Rivers, and my own credit experience. I have relied upon and assumed the accuracy and completeness of such information without performing any independent verification.

III. CREDIT RATING ISSUES

Q. Which ratings agencies rate electric cooperative G&Ts?

A. There are three major rating agencies: Standard & Poor's, Moody's Investors Service, and Fitch Ratings. G&T cooperative ratings vary among the three rating agencies. Electric cooperatives tend to be rated out of S&P's and Fitch's Public Power groups, which focus primarily on rating not-for-profit municipal electric systems and rural electric cooperatives. Moody's evaluates investor-owned utilities and large not-for-profit electric systems, including rural electric cooperatives, as part of its Global Infrastructure group (Power/Utilities-Americas).

Q. What range of ratings do electric cooperative G&Ts typically receive?

A. G&T cooperatives' ratings range from a high of 'AA' for Associated Electric Cooperative, Missouri, to a low of 'BBB-' for Big Rivers. Most G&T cooperative ratings tend to be in the 'A' to upper 'BBB'/'Baa' categories. The majority of rating outlooks is stable, with a slight increase in negative outlooks. I have attached to this testimony as Exhibit Spen-1 lists showing the range of ratings assigned by S&P, Fitch and Moody's.

Q. What characteristics of electric cooperatives are considered by the ratings agencies when assigning ratings?

A. The most significant rating components for the electric cooperative sector have remained relatively stable. But selective items and weightings incorporated in the rating process will vary depending upon an agency's rating guidelines and the near-term "key credit drivers" for that agency. Credit elements with most significance include: (i) Management, Governance and Business Strategy; (ii) Service Area; (iii) Asset Performance; (iv) Cost Structure; (v) Rates and Regulation and (vi) Financial Results and Legal.

Q. What is the general outlook for the electric cooperative G&T credit rating sector?

A. At the start of 2011, each of the rating agencies published research reports or provided commentaries regarding the electric industry's performance in 2010 and their respective outlooks for 2011, including thoughts on the electric cooperative sector. Moody's published a special comment report--*Key Drivers for U.S. Electric Generation & Transmission Cooperative Rating Actions in 2010.* The agency summarized its findings stating that the number of upgrades versus downgrades and outlook changes were essentially evenly balanced in 2010, but fundamentals appear more negatively biased. There were a myriad of reasons for the rating actions in the G&T sector, and the rating service went on to say that it continues to view the fundamental credit conditions in the U.S. power sector, including investor-owned utilities, public power systems and G&T cooperatives as stable. Prospectively, the rating service went on to say that they continue to view the G&T cooperative sector as stable and incorporate a view that cooperatives will target financial profiles commensurate with their respective rating categories, maintain adequate liquidity sources to meet their near-term working capital needs and continue to operate their businesses in a relatively conservative manner. On a January 25th conference call, Moody's also affirmed the importance of strong utility regulation in an analysis titled *Regulations Provides Stability as Risks Mount*. The rating agency reaffirmed its stable outlook for the regulated power sector, but longer term mentioned concerns about customers' willingness to support rate hikes.

Q. Has Standard & Poor's offered any outlook for the year?

A. *Electric Utility Week* reported in an article in a December 2010 issue that S&P analyst Peter Murphy stated that the rating industry sees regulatory uncertainty as a big issue for public power in 2011. The challenge for public power is that they must look through the present, short-term issues and plan for the next 20 to 30 years. On the plus side, the rating agency continues to feel that the outlook for public power utilities remains stable.

Q. What is Fitch's current outlook for cooperative ratings?

A. Fitch Ratings on January 18, 2011, published its *2011 Outlook: U.S. Public Power and Electric Cooperative Sector* report. The agency's rating outlook is for continued stability in 2011. Fitch stated that in spite of the barrage of negative press reports on municipal credit quality, its outlook for public power (municipal electric systems) and electric cooperatives remains stable through 2011. Overall, Fitch's portfolio of public power and cooperative issuers is expected to carry on with their strategy of providing reliable, low-cost electric service and maintaining stable financial and operational performance.

Q. What are the most important factors considered by the ratings agencies when rating electric cooperatives?

A. There are certain key ratings factors or credit factors that are most often used in analyzing and rating a G&T cooperative credit. Evaluating a G&T electric cooperative incorporates a number of "qualitative" and "quantitative" measures. It is essential to fully understand a utility system's primary business strategy and its goals. Once these are defined, the eventual success of the long-term business plan will depend on a utility management and its board's ability to execute and meet future challenges. Factored in the analysis are items such as management and business strategies, service area characteristics, the quality and performance of its generating and transmission systems, its rate structure, past financial performance, future financial and rate requirements, level of member support, along with other meaningful factors.

Q. How do the ratings agencies evaluate future financial performance and rate requirements?

A. The rating agencies have begun to incorporate more possible credit risk scenarios into their basic credit rating models. Global issues, increased fuel volatility, risk of greater inflation and recent concerns about financial liquidity and capital market access have resulted in the agencies requiring bond issuers to include more sensitivity analyses as part of the normal rating process. Since municipal electric systems and rural electric cooperatives tend to employ a less risky business model than most other business sectors, along with the benefit of self-regulation, which allows for more predictable financial results, the degree of stress-test analysis is not as intense as some other industries. In addition to an annual "base case" scenario required by the agencies, utility management can also incorporate alternative scenarios, such as a "low case" and a "high case," with various assumptions spelled out.

Q. You earlier mentioned the concept of "key credit drivers." What are the key credit drivers for electric cooperative G&Ts in the ratings process?

A. Key credit drivers is a newer concept generally used by the rating agencies to highlight secular electric industry trends that could have a material impact on electric system credits, either favorably or negatively. The list will be adjusted or reprioritized, as appropriate, to changes in global or domestic energy, business or legislative policies. If the rating agencies deem certain factors to be potentially significant, they will request utilities to incorporate these factors in their plans and provide the potential impact on their business and financial models.

The following are examples of current key credit drivers for electric cooperatives--

- Future role of RUS-particularly how this relates to funding needs and power supply selection
- Environmental issues; role of EPA
- Liquidity-short-term financial sufficiency
- Rate setting (use of power cost adjustment mechanisms)
- Economy
- Inflation
- Potential Federal energy legislation.

Q. Please compare Big Rivers' credit rating with that of other comparable G&Ts.

A. The tables attached to my testimony as Exhibit Spen-2 list the various electric cooperative ratings by the three rating agencies. The data shows that S&P rates the largest group of cooperatives, with Moody's and Fitch having approximately the same number of ratings. In comparing G&T ratings, it is clear that Big Rivers' credit ratings of

"BBB-" from Fitch and S&P are at the low end of their respective credit rating universe. For Moody's, its "Baa1" is also at the lower end of its G&T rated issuer group, but there are several other G&T credits rated at that level.

Q. Do you have an opinion about why the range of Big Rivers' ratings is at the bottom of the G&T ratings spectrum?

A. Yes. There are a number of reasons for Big Rivers' lower credit rating among the three agencies. Most of these are well known, and include the cooperative's prior bankruptcy and reorganization, the extreme reliance on two large industrial commodity based companies, historically weak financial ratios, uncertainties created by concerns about Kentucky Public Service Commission rate regulation, and environmental risks associated with its large fleet of older, coal-based generation. While the recent "unwind transaction" has significantly benefited Big Rivers' financial position, by substantially improving debt coverage ratios, equity to capitalization levels and cash and financial liquidity, the lack of a longer-term positive track record and the continued risks associated with the heavy reliance on a limited number of major power customers with generally weak contractual commitments, likely makes it problematic for the rating agencies to adjust credit ratings upward in the very near term.

Financial ratios for the most recent reporting period for Big Rivers do compare well with many of the other G&Ts. But in looking at an extended financial history over the past three to five years, which is more typical for rating agency comparisons, Big Rivers' financial metrics are well below average. This is borne out by Fitch Ratings' *Public Power 2010 Cooperative Stats*, dated June 1, 2010, which shows that trends for most G&Ts have been significantly higher than those of Big Rivers for a much longer period of time. Should Big Rivers be able to continue to demonstrate consistent financial results around the levels projected in the *pro forma* financials, further improvement in its credit ratings might be possible.

Q. Can you identify the principal financial measures that the rating agencies are likely to evaluate in determining whether Big Rivers' investment grade rating continues to be warranted?

A. The primary financial measures used by the rating agencies are: Debt Service Coverage ("DSC"), Times Interest Earned Ratio ("TIER"), Equity to Total Capitalization, and Financial Liquidity. While Moody's tends to use more of a quantitative based rating methodology for electric utility credits, none of the rating agencies have precise numerical targets for assigning credit ratings. With that in mind, typically for an 'A' category credit, the three rating agencies would prefer G&T cooperative issuers to have annual DSC and TIER ratios of around 1.20 times (x), equity to total capitalization ratios of approximately 20%, and liquid reserves and credit facilities in the range of 120 to 180 days. Cash and liquid investments are generally preferred to bank credit facilities; but a balanced combination is acceptable. This assumes that the remaining credit factors are satisfactory.

In the case of Big Rivers, given its past financial difficulties, the high reliance on two larger smelters and PSC oversight, we believe that , among other things, Big Rivers needs to demonstrate a higher level of financial protection than other G&Ts, and that targeting a minimum annual debt service coverage ratio of 1.25x, equity as a percentage of total capitalization of greater than 20% and total financial reserves of around the 180 day level, are necessary for Big Rivers to maintain its current credit ratings. Moreover, as Mr. Blackburn testifies (Exhibit No. 49), Big Rivers has undertaken financial covenants with its creditors and will be required to refinance significant amounts of debt over the next few years. Big Rivers needs to maintain the Margins for Interest Ratio under its Indenture and other debt instruments in order to secure that refinancing. (Exhibit No. 49), and its investment-grade credit ratings to secure that refinancing at favorable rates.

Q. Please describe the major positive and negative credit factors directly underlying Big Rivers' ratings.

A. The following is a list of positive and negative credit factors that, in my opinion, are considered significant by the ratings agencies evaluating Big Rivers. This discussion takes into account the termination in 2009 of the of long-term lease and purchase power arrangements with subsidiaries or affiliates of an investor-owned utility, and the resulting improvement in Big Rivers' financial position.

A. POSITIVE FACTORS

- Much Improved Financial Position--The unwind transactions resulted in Big Rivers eliminating its deficit net worth, with equity to total capital approximating 30% (among the highest percentages in the G&T universe); and partial utilization of the $508.5 million in cash payments used to repay about $140 million of debt owed to the Rural Utilities Service ("RUS"), and the establishment of $252.9 million of reserves (i.e., $157 million economic reserve for future environmental cost increases, a $35 million Transitional Reserve to mitigate potential costs if the smelters decide to terminate their agreements or load, and a $60.9 million Rural Economic Reserve). Also, Big Rivers has supplemented its internal funds with additional lines of credit.
- Long Term Wholesale Power Contracts--The G&T and its members recently extended their long-term wholesale contracts to December 31, 2043, which currently extends beyond Big Rivers' final debt maturities.
- Low Cost Generation--Big Rivers owns generating capacity of about 1,440 megawatts ("MW") in four coal-fired plants. Total power capacity is about 1,833 MW including rights to about 207 MW of coal-fired capacity from Henderson Municipal Power and Light Station Two and about 178 MW contracted hydro

capacity from Southeastern Power Administration. This capacity provides Big Rivers with a competitive energy supply for its members and for marketing opportunities in the region.

- Electric Rates Competitive--Wholesale rates to the members are around $35 per MWh, which translates into member retail rates to non smelter customers around 7 cents per KWh; which is highly competitive for the area.
- Minimum Coverage Defined--Under contract terms with the two smelters, Big Rivers is assured, within the limits of the TIER support formula in the Smelter contracts, of maintaining a TIER of 1.24x, providing reasonable cushion under its financial covenants.

B. NEGATIVE FACTORS

- Customer Concentration--The two smelters served by Kenergy normally consume over 7 million MWh of energy annually at full load, accounting for a substantial load concentration risk. Contractual agreements with the smelters are considered weak. Given the cost effective power being provided by Big Rivers to allow Kenergy to service this load and the current improved outlook for aluminum smelters, the likelihood of the customers not meeting their financial obligations or possibly opting out of their contractual agreements on short-term notice, which they have the right to do, does not appear likely. However, this remains a meaningful concern overarching the credit and acts as a constraint on Big Rivers' credit rating.
- Regulatory Risk--Big Rivers is subject to regulation for rate setting purposes by the Kentucky PSC, which is not typical for G&T cooperatives. State regulation of rates can pose some level of challenge in obtaining timely and adequate rate relief. The use of certain fuel cost, environmental cost and purchased power cost

adjustment mechanisms is beneficial since they can help mitigate the risk of cost recovery shortfalls.

- Large Reliance on Coal-Fired Generation--Big Rivers is substantially dependent on coal-fired generation, and therefore may face a higher risk from future environmental legislation or EPA mandates. Big Rivers has already retrofitted most of its existing generation capacity with pollution control technologies that allow it to meet known Clean Air standards.
- Ability to Market Excess Power--Big Rivers sells a portion of its electricity off system and is therefore dependent on the existing market clearing price, transmission interconnections and operating performance of its plants. Also, in the event of a smelter's decision to reduce its current demand or terminate operation, Big Rivers needs to be able to market the surplus power to other customers. The utility is bolstering its transmission capability, works with ACES Power Marketing and integrated as a full member of the Midwest ISO on December 1, 2010, which should all be helpful in increasing marketing opportunities.
- Litigation--Big Rivers and Henderson Municipal Power and Light are currently in litigation over a contract provision.

Q. Do you believe Big Rivers can retain its investment grade credit ratings if the Commission approves the proposed rate adjustment?

A. Yes. While the number of positive and negative credit factors largely demonstrate a balanced credit profile, the significance of certain negative factors results in a more negative bias to Big Rivers' credit rating. The unwind transaction significantly helps offset prior risks and uncertainties, but it remains essential that Big Rivers, with supportive PSC rate relief, be diligent in making good business decisions, achieving solid business performance and maintaining very healthy financial ratios. In my view, the proposed rate adjustment would provide the necessary demonstration in this regard to maintain Big Rivers' current credit ratings.

Further, I believe it is prudent to say that the credit markets generally recognize the importance of the Kentucky G&T cooperative having ample revenue and cash flow to meet its operating budget, pay debt service and achieve its financial coverage goals. The PSC's approval of Big Rivers' rate proposal would most certainly be viewed positively by both the markets and the rating services. Without the full rate increase requested by Big Rivers, Big Rivers' financial ratios would decline, and it may lose one or more of its investment grade credit ratings, which would likely mean, at a minimum, higher borrowing costs. If Big Rivers does not maintain two investment grade credit ratings, it will be required by the RUS to file promptly for additional rate relief that will position it to obtain those investment grade credit ratings. In the worst case, loss of investment grade credit ratings could jeopardize the solvency and indeed the very existence of Big Rivers.

Q. Can you provide an analysis of how Big Rivers' credit ratings could affect its debt costs in the credit markets?

A. Yes. With respect to the effect of Big Rivers' credit ratings on its debt costs, I have attached to my testimony as Exhibit Spen-3 two charts--Current U.S. Utilities Fair Market Sector Yield Curve and Historical 20-Year U.S. Utilities Fair Market Sector Yields--that demonstrate the sharply higher yields that would have to be paid if Big Rivers were not rated investment grade. A rating downgrade, out of the investment grade category, or a downward adjustment in the credit outlook to negative from stable, would certainly result in sharply higher interest rates to Big Rivers and higher electric bills to its customers.

Q. As you have stated, Big Rivers has three investment grade ratings. If only one or two of Big Rivers' ratings dropped below investment grade, would that adversely affect the cost of its debt?

A. If Big Rivers lost one of its investment grade ratings, or its outlook was changed to "negative," in all likelihood there would be some negative effect. We must remember that Big Rivers starts with marginal investment grade ratings. The credit markets pay more attention to negative news about a credit that is on the ratings edge. Furthermore, it is my understanding that if Big Rivers does not maintain at least two investment grade ratings, it will be in violation of the terms of its loan contract with the United States. That would likely have a negative effect on the credit markets.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Fitch Ratings (www.fitchratings.com)	Moody's Investors Service (www.moodys.com)	Standard & Poor's (www.standardandpoors.com)
Long Term Ratings:		
AAA	Aaa	AAA
AA+, AA, AA-	Aa1, Aa2, Aa3	AA+, AA, AA-
A+, A, A-	A1, A2, A3	A+, A, A-
BBB+, BBB, BBB-	Baa1, Baa2, Baa3	BBB+, BBB, BBB-
BB+, BB, BB-	Ba1, Ba2, Ba3	BB+, BB, BB-
B+, B, B-	B1, B2, B3	B+, B, B-
CCC+, CCC, CCC-	Caa1, Caa2, Caa3	CCC+, CCC, CCC-
CC	Ca	CC
C	C	C
DDD	--	D
DD	--	--
D	--	--
Short Term Ratings:		
F1+, F1	MIG 1/VMIG 1	SP-1+, SP-1
F2	MIG 2/VMIG 2	SP-2
F3	MIG 3/VMIG 3	SP-3
B	SG	--
C	--	--
D	--	--

FitchRatings
KNOW YOUR RISK

G&T Cooperative Medians

	Total Revenues	Total Members	DSC (x)	Debt / FADS	Days Cash on Hand	Days Liquidity on Hand	Capex/ Depreciation (x)	Equity / Capitalization	Var Rate Exp / Total Debt
FILTERED MEDIAN	849,985	23	1.28	10.8	60	209	3.5	20	-
AA	921,024	88	1.24	13.1	113	208	9.4	19	8
A	595,405	23	1.28	10.5	55	206	3.5	18	-

(To compare an issuer's metrics to the medians, select the issuer's name from the drop down menu below.)

Rated Company	Rating	Rtg Values	Region	Primary Fuel Exposure	Total Revenues	Total Members	DSC (x)	Debt / FADS	Days Cash on Hand	Days Liquidity on Hand	Capex/ Depreciation (x)	Equity / Capitalization	Var Rate Exp / Total Debt
Associated Electric Cooperative Inc.	AA	2.0	SERC	Coal	938,838	51	1.43	8.4	60	210	4	19	-
Basin Electric Power Cooperative and Subsidiaries	AA-	2.3	Midwest	Coal	832,950	125	1.04	17.7	166	225	15	20	12.5
Arkansas Electric Cooperative Corporation	A+	2.7	SERC	Coal	420,992	17	1.01	8.5	42	143	3	45	-
Buckeye Power Inc.	A+	2.7	Central	Coal	471,536	24	1.18	10.7	12	72	8	20	-
Brazos Electric Power Cooperative Inc.	A	3.0	ERCOT	Gas	954,292	18	1.84	13.8	1	255	14	44	-
Oglethorpe Power Corporation	A	3.0	SERC	Coal	1,145,284	39	1.28	12.2	288	259	7	11	18.0
Old Dominion Electric Cooperative	A	3.0	Central	Coal/Nuclear	713,199	11	1.45	7.3	4	526	1	31	-
Tri-State Generation & Transmission Association Inc	A	3.0	WECC	Coal	1,102,896	44	1.22	8.8	60	128	3	23	-
Central Iowa Power Cooperative	A-	3.3	Midwest	Coal	137,510	20	1.34	8.4	161	454	1	24	16.6
Golden Spread Electric Cooperative	A-	3.3	ERCOT/SPP	Gas	345,841	16	2.84	5.1	113	307	2	49	29.2
Great River Energy	A-	3.3	Midwest	Coal	787,780	28	1.28	11.8	128	418	5	12	-
PowerSouth Energy Cooperative & Subs	A-	3.3	SERC	Coal	549,987	20	1.27	10.8	94	99	2	11	-
South Texas Electric Cooperative Inc.	A-	3.3	ERCOT	Coal	377,880	8	1.62	17.8	60	467	17	12	-
Western Farmers Electric Cooperative	A-	3.3	SPP	Coal	350,785	15	1.19	10.9	3	44	4	15	-
Big Rivers Electric Corp	BBB	4.0	Various	Coal	373,380	3	2.72	2.5	78	309	2	31	-

Source: 2009 Audited Financials

Case No. 2011-00036
Exhibit Spen-2
Page 1 of 3

The current ratings for the electric cooperatives that S&P rates are as follows:

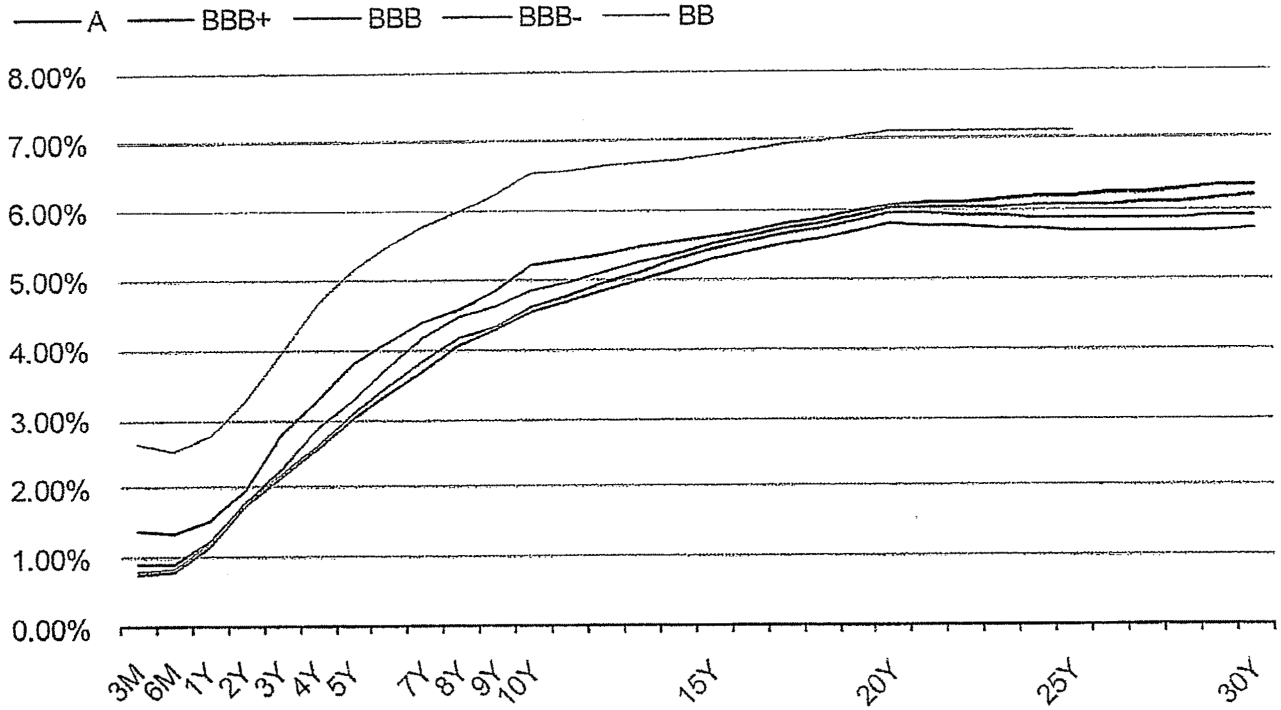
Chugach Electric Association	AK	A-	STABLE
Baldwin Electric Membership Cooperative	AL	A	STABLE
PowerSouth Energy Cooperative	AL	A-	STABLE
Arkansas Electric Cooperative Corp	AR	AA-	STABLE
Tri-State Generation & Transmission Association	CO	A	STABLE
Seminole Electric Cooperative	FL	A-	STABLE
Diverse Power Inc	GA	A	STABLE
Georgia Transmission Corp	GA	AA-	STABLE
Oglethorpe Power Corporation	GA	A	STABLE
Central Iowa Power Cooperative	IA	A	STABLE
Hoosier Energy Rural Electric Cooperative Inc	IN	A	STABLE
Wabash Valley Power Association	IN	A-	STABLE
Big Rivers Electric Corp.	KY	BBB-	STABLE
Peninsula Generation Co-op	MI	A-	STABLE
Great River Energy	MN	A-	STABLE
Associated Electric Cooperative Inc	MO	AA	STABLE
South Mississippi Electric Power Association	MS	BBB+	POSITIVE
Southern Montana Elec Generation & Transmission Co-op	MT	BBB	STABLE
Brunswick Electric Membership Corporation	NC	A	STABLE
North Carolina Elec Membership Corp	NC	A-	STABLE
Basin Electric Power Cooperative	ND	A+	STABLE
Square Butte Electric Cooperative	ND	A-	STABLE
Buckeye Power Inc	OH	A-	STABLE
Buckeye Pwr Gen LLC	OH	A-	STABLE
Western Farmer's Electric Cooperative	OK	BBB+	NEGATIVE
Central Electric Power Cooperative Inc	SC	AA-	STABLE
Brazos Electric Power Cooperative Inc	TX	A-	STABLE
Golden Spread Elec Co-op	TX	A	STABLE
Guadalupe Valley Elec Cooperative Inc.	TX	A+	STABLE
San Miguel Electric Cooperative Inc.	TX	A-	STABLE
South Texas Electric Cooperative	TX	A-	STABLE
Old Dominion Electric Cooperative	VA	A	STABLE
Vermont Electric Cooperative Inc	VT	BBB	POSITIVE
Dairyland Power Cooperative	WI	A	STABLE

G&T Cooperative	Moody's Rating <1>	Rating Outlook
Arkansas Electric Cooperative	A1 senior secured	stable
Associated Electric Cooperative	A1 senior secured	stable
Basin Electric Power Cooperative	A1 senior secured	negative
Big Rivers Electric	Baa1 senior secured	stable
Buckeye Power	A2 senior secured	negative
Chugach Electric Association	A3 senior unsecured	stable
Dairyland Power	A3 Issuer Rating	stable
Georgia Transmission	A3 senior secured	stable
Golden Spread	A3 Issuer rating	stable
Great River	A3 senior secured	negative
Hoosier	Baa1 senior secured	positive
Minnkota	Baa1 Issuer rating	stable
Oglethorpe	Baa1 senior secured	stable
Old Dominion	A3 senior secured	stable
Power South	A3 senior secured	stable
Seminole	A3 senior secured	stable
South Mississippi	A3 senior secured	stable
Tri-State	A3 senior secured	stable

<1> as of February 3, 2011

Current U.S. Utilities Fair Market Sector Yield Curve

US Utility	3M	6M	1Y	2Y	3Y	4Y	5Y	7Y	8Y	9Y	10Y	15Y	20Y	25Y	30Y
A	0.75%	0.79%	1.16%	1.76%	2.18%	2.58%	3.03%	3.70%	4.05%	4.27%	4.54%	5.30%	5.80%	5.71%	5.72%
BBB+	0.78%	0.82%	1.19%	1.78%	2.19%	2.61%	3.09%	3.82%	4.16%	4.34%	4.62%	5.44%	5.97%	5.87%	5.92%
BBB	0.88%	0.88%	1.22%	1.78%	2.27%	2.87%	3.27%	4.17%	4.46%	4.61%	4.83%	5.51%	6.04%	6.06%	6.17%
BBB-	1.37%	1.34%	1.53%	1.98%	2.79%	3.29%	3.81%	4.41%	4.57%	4.85%	5.23%	5.62%	6.09%	6.19%	6.31%
BB	2.65%	2.55%	2.75%	3.28%	3.94%	4.65%	5.14%	5.79%	5.99%	6.22%	6.51%	6.77%	7.13%	7.10%	



Source: Bloomberg; As of 01/31/2011

FMC Curves are created using prices from new issue calendars, trading/portfolio systems, dealers, brokers, and evaluation services which are fed directly into the specified bond sector databases on an overnight bases. All prices are used.

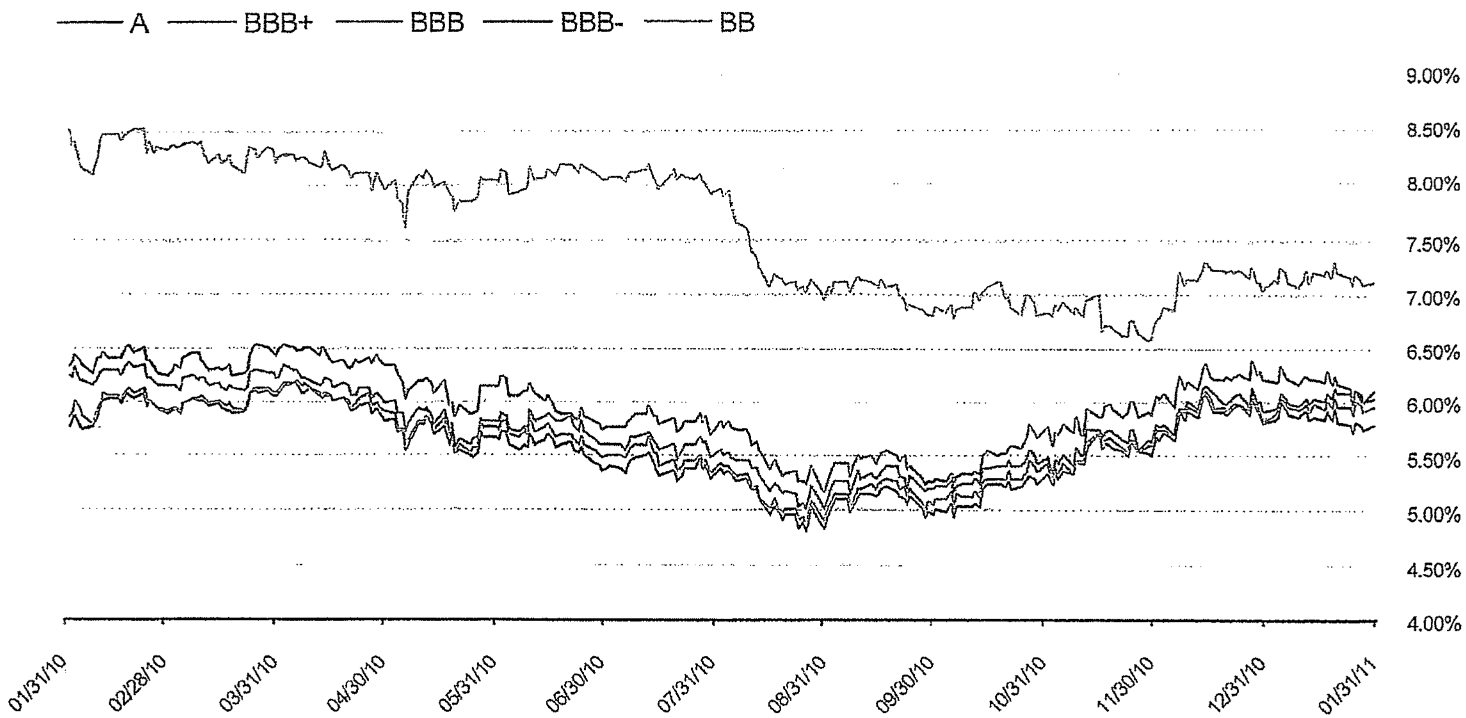
All bonds for each sector are then subject to option adjusted spread analysis and the option-free yields are then plotted to form a fair market yield curve without any yields being distorted by embedded calls, puts, or sinks. This allows bonds with very different structures to be compared on an equivalent basis. A best fit curve is then drawn from the option-free yields, resulting in specific yield curve for each bond category.

Debt issues are divided into hundreds of sectors that are grouped by several variables such as rating or industry type. The sectors are numbered, and an option-free yield curve is constructed daily for each sector. The ratings categories for each sector are expressed as Bloomberg Composite Ratings, which are blends of Moody's Investor Service, and Standard & Poor's ratings.

Case No. 2011-00036
Exhibit Spen-3
Page 1 of 2

Historical 20-Year U.S. Utilities Fair Market Sector Yields

US Utility	Current	Last Month	3 Months Ago	6 Months Ago	1 Year Ago
A	5.80%	5.80%	5.33%	5.38%	5.78%
BBB+	5.97%	5.81%	5.43%	5.43%	5.86%
BBB	6.04%	5.91%	5.48%	5.55%	6.23%
BBB-	6.09%	6.21%	5.76%	5.81%	6.34%
BB	7.13%	7.04%	6.83%	7.94%	8.51%



Source: Bloomberg; As of 01/31/2011

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Exhibit Spen-3
Page 2 of 2

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**

DIRECT TESTIMONY

OF

JOHN WOLFRAM
SENIOR CONSULTANT
THE PRIME GROUP, LLC

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
JOHN WOLFRAM

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DIRECT TESTIMONY
OF
JOHN WOLFRAM

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. By whom are you employed?

A. I am a Senior Consultant with The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting services in the areas of utility rate analysis, cost of service, rate design and other utility regulatory matters.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Big Rivers Electric Corporation ("Big Rivers").

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

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Notre Dame in 1990 and a Master of Science degree in Electrical Engineering from Drexel University in 1997. In March 2010, I joined The Prime Group LLC as a Senior Consultant. In this role I have developed cost of service studies and rates for numerous electric and gas utilities, including electric distribution cooperatives, generation and transmission cooperatives,, municipal utilities and investor-owned utilities. I have also performed economic analyses, rate mechanism reviews, ISO/RTO membership evaluations, and wholesale formula rate reviews. From July 1997 to February 2010, I was employed by the parent companies of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"). During that time I held several roles, advancing through positions in the Energy Marketing, Generation Planning, Rates & Regulatory, and Customer Service areas. Prior to my work with LG&E and

KU, I was employed by the PJM Interconnection and by the Cincinnati Gas & Electric Company. A more detailed description of my qualifications is included in Exhibit Wolfram-1.

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

A. Yes. I have testified in numerous regulatory proceedings before this Commission. A listing of my testimony in other proceedings is included in Exhibit Wolfram-1.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support (i) certain Filing Requirements from 807 KAR 5:001, (ii) the Revenue Requirements, and (ii) certain Pro Forma Adjustments.

Q. Do you sponsor any exhibits to your testimony?

A. Yes. I have prepared the following exhibits to my prepared testimony:

Exhibit Wolfram-1 – Qualifications of John Wolfram

Exhibit Wolfram-2 - Revenue Requirements Analysis

III. FILING REQUIREMENTS

Q. Have you reviewed the answers provided in Exhibits 1-47 which address Big Rivers' compliance with the historical period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of Exhibits 1-47 for which I am identified as the sponsoring witness as part of this Direct Testimony.

IV. REVENUE REQUIREMENT

Q. Please describe Exhibit Wolfram-2 and its purpose.

A. Exhibit Wolfram-2 shows the Big Rivers electric revenue requirement for the twelve months ended October 31, 2010. The first page of the exhibit shows total amounts per books for operating revenue and patronage capital, cost of electric service, interest income, other non-operating income, other capital credits/patronage dividends, and extraordinary items. These items are listed in lines 1 through 8 of page 1 of Exhibit Wolfram-2 and reflect the starting point for the revenue deficiency determination for the test year.

The test year must then be adjusted to reflect known and measurable changes in revenues and expenses that can be expected to occur during the period the proposed rates will be in effect. This Exhibit sets forth adjustments for known and measurable changes, and eliminates unrepresentative conditions in order to "pro form" or make the test year suitable for use in determining the deficiency of current electric revenues. This Exhibit also includes adjustments to remove the effects of other rate mechanisms in order to limit the deficiency determination to base revenues. A further description of, and support for, each adjustment is contained in supporting Reference Schedules 2.01 through 2.26 of this Exhibit. The applicable Reference Schedule is noted in column 1 and the witness supporting the proposed adjustment is identified in column 2. The effect of each adjustment is shown in columns 3, 4 and 5 for Revenue, Expense, and Margin(Deficit), as applicable. The adjustments are listed beginning on line 10 on page 1 of Exhibit Wolfram-2.

The exhibit then shows the Adjusted Net Margin (Deficit) resulting from the total per books and adjustments, on the last line of Exhibit Wolfram-2, page 1. The second page of Exhibit Wolfram-2 shows the calculation of the revenue deficiency.

Q. Please explain the calculation of the revenue deficiency on page 2 of Exhibit Wolfram-2.

A. To determine the overall revenue deficiency, the Adjusted Net Margin (Deficit) calculated on page 1 of Exhibit Wolfram-2 is compared to the margin that is required in order to achieve a Contract TIER of 1.24. The difference is the Revenue Deficiency shown on page 2, line 8.

Q. What is the Conventional TIER referenced in Exhibit Wolfram-2?

A. The Conventional TIER is the traditional Times Interest Earned Ratio approach used to determine revenue requirements for non-profit cooperatives. This approach sets the revenue requirement equal to the expenses plus a margin, where the margin equals the revenue less expenses (other than interest expense) sufficient to cover interest on long-term debt by a certain ratio -- namely, the target TIER ratio.

Q. What is the Contract TIER referenced in Exhibit Wolfram-2?

A. Big Rivers has special contracts in place for two aluminum smelters, Rio Tinto Alcan ("Alcan") and Century Aluminum ("Century") (collectively, "Smelters"). These special contracts ("Smelter Agreements") specify a TIER Adjustment Charge. The contracts were approved by the Commission in association with the transaction that unwound Big Rivers' 1998 lease with E.ON U.S., LLC ("E.ON") and its affiliates (the "Unwind Transaction"), described in Case No. 2007-00455, *In the Matter of: The Application of Big Rivers Electric Corporation For: (1) Approval Of Wholesale Tariff Additions For Big Rivers Electric Corporation, (2) Approval Of Transactions, (3) Approval Of Evidences Of Indebtedness, And (4) Approval Of Amendments To Contracts; And Of E.ON U.S., LLC, Western Kentucky Energy Corp. And LG&E Energy Marketing, Inc. For Approval Of Transactions* (the "Unwind Proceeding"). The TIER Adjustment Charge for both Smelters is specified in Section 4.7 of the Smelter Agreements. The contracts specify in Section 4.7.5(f) that:

> It shall be assumed that: The Rural Economic Reserve, the Economic Reserve, and the Transition Reserve shall not generate any revenue or tax liability and the application of funds from the Rural Economic Reserve, the Economic Reserve, or the Transition Reserve shall not result in any change in the Net Margins of Big Rivers.

Thus, pursuant to the Smelter Agreements, the TIER is adjusted to exclude from the margin calculation any interest income on the Transition Reserve account. During the test year, Big Rivers recorded interest income on the Transition Reserve. For the Contract TIER, this interest income is removed from the Adjusted Net Margin(Deficit) of the Conventional TIER. In other words, the margins required for the Contract TIER are the margins required for the Conventional TIER with the interest income on the Transition Reserve excluded.

Q. Is it appropriate for Big Rivers to establish a revenue requirement based on Contract TIER rather than Conventional TIER?

A. Yes. It is appropriate to use the Contract TIER to establish the revenue requirement for Big Rivers because the Smelter Agreements base the TIER Adjustment Charge on Contract TIER. The Smelter Agreements effectively establish a "bandwidth" for the Smelters' TIER Adjustment Charge, which Mr. William Steven Seelye discusses in his testimony. If Big Rivers exceeds the 1.24 Contract TIER, then Big Rivers would be subject to rebating any of the excess margins to the Smelters under Section 4.9 or Section 4.10 of the Smelter Agreements and to the Non-Smelters under the Rebate Adjustment. In other words, any Big Rivers margins in excess of the 1.24 Contract TIER may be rebated to both the Smelters and the Non-Smelter members alike. From a practical standpoint, because of the Smelter Agreements and the Rebate Adjustment, Big Rivers can effectively achieve no greater than the 1.24 Contract TIER.

V. PRO FORMA ADJUSTMENTS

Q. Please broadly describe the nature of the pro forma adjustments made to Big Rivers' electric operations for the test year ended October 31, 2010 shown in Exhibit Wolfram-2.

A. For the test year ended October 31, 2010, Big Rivers has made adjustments which:

a) Annualize year-end facts and circumstances and adjust for other known and measurable changes (Reference Schedules 2.01, 2.04, 2.06, 2.08, 2.10, 2.11, 2.12, 2.15, 2.18, 2.24, 2.26);

b) Eliminate the effect of items included in other rate mechanisms (Reference Schedules 2.02, 2.03, 2.05); and

c) Adjust for other unusual, non-recurring, or out-of-period items in the test year (Reference Schedules 2.07, 2.09, 2.13, 2.14, 2.16, 2.17, 2.19 - 2.23, and 2.25).

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 2.01 of Exhibit Wolfram-2.

A. This adjustment has been made to annualize the revenues and expenses associated with a new industrial customer. Equality Mine, a Kenergy customer on the Large Industrial Customer rate, was added on March 16, 2010. Thus the test year reflects only 7.5 months of revenues and expenses associated with this customer; both the revenues and the expenses are understated for a twelve month prospective period. To annualize the revenues associated with this customer, the revenues were escalated by the ratio of a full twelve calendar months to the number of actual months served, resulting in an upward adjustment to electric operating revenues.

The additional operating expenses associated with serving this customer were calculated by applying an operating ratio to the revenue adjustment. Consistent with

Commission practice, the operating ratio of 0.74 was calculated by dividing operation and maintenance expenses, exclusive of wages and salaries, benefits and pensions, and regulatory commission expenses, by base rate revenues as billed at the currently-effective rates. When applied to the new industrial customer revenue adjustment, the application of the operating ratio resulted in an upward adjustment to expenses.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 2.02 of Exhibit Wolfram-2.

A. This adjustment has been made to account for the timing mismatch in fuel cost expenses and revenues under the Fuel Adjustment Clause ("FAC") for the twelve months ended October 31, 2010. Consistent with Commission practice, the mismatch between fuel costs and fuel cost recovery through Big Rivers' FAC has been eliminated. These over- and under-recoveries were taken directly from Big Rivers' monthly FAC filings. The Commission approved similar adjustments for KU and LG&E in Case Nos. 2003-00433 and 2003-00434 respectively. KU and LG&E proposed this same adjustment in Case Nos. 2008-000251, 2008-00252, 2009-00548 and 2009-00549.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 2.03 of Exhibit Wolfram-2.

A. This adjustment has been made to remove Environmental Surcharge ("ES") revenues and expenses because these are addressed by a separate rate mechanism. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate ES revenues and expenses during the test year. The ES provides for full recovery of approved environmental costs that qualify for the surcharge, and thus these should be excluded from base rates. These costs were taken directly from Big Rivers' monthly ES filings. The Commission approved essentially similar adjustments for KU and LG&E in Case

Nos. 2003-00433 and 2003-00434 respectively. KU and LG&E proposed this same adjustment in Case Nos. 2008-000251, 2008-00252, 2009-00548 and 2009-00549.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 2.04 of Exhibit Wolfram-2.

A. This adjustment has been made to reflect weather normalized electric sales margins. The revenue and expense adjustments were prepared by Mr. Seelye and are discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 2.05 of Exhibit Wolfram-2.

A. This adjustment has been made to eliminate the expenses and revenues associated with the Non-FAC Purchased Power Adjustment ("Non-FAC PPA") which are addressed by a separate rate mechanism. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate Non-FAC PPA revenues and expenses during the test year.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.06 of Exhibit Wolfram-2.

A. This adjustment has been made to reflect annualized depreciation expenses. This includes a full year's depreciation expense on total utility plant in service as of October 31, 2010. The depreciation rates reflect those sponsored by Mr. Ted J. Kelly in his testimony. This adjustment was prepared by Mr. Mark A. Hite and is discussed in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.07 of Exhibit Wolfram-2.

A. This adjustment has been made to reflect increases in labor and labor-related overhead costs as applied to the twelve months ended October 31, 2010. This adjustment was prepared by Mr. Hite and is discussed in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.08 of Exhibit Wolfram-2.

A. This adjustment has been made to reflect the current interest on Construction Work In Progress ("CWIP") Big Rivers is seeking current recovery of interest capitalized on CWIP, consistent with permissible ratemaking practices in Kentucky. This adjustment was prepared by Mr. Hite and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 2.09 of Exhibit Wolfram-2.

A. This adjustment has been made to eliminate the revenues and expenses associated with Big Rivers' contract with RRI Energy, Inc. to provide backup services for the Domtar Cogenerator. The contract expires in March 2011 and will not be renewed. Since Big Rivers became a transmission-owning member of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") on December 1, 2010, Big Rivers will rely on the Midwest ISO for backup services for the Domtar Cogenerator upon the expiration of the RRI contract, and will pass all costs associated with the same on to Domtar. Because the revenues and expenses associated with the RRI contract are non-recurring, this adjustment removes them from the test year results. This adjustment was prepared by Mr. Hite and is discussed in his testimony

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.10 of Exhibit Wolfram-2.

A. This adjustment reflects normalized production non-labor operations and maintenance expenses, excluding planned outage expenses. This adjustment was prepared by Mr. Robert W. Berry and is discussed in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.11 of Exhibit Wolfram-2.

A. This adjustment reflects normalized non-labor production planned outage expenses. This adjustment was prepared by Mr. Berry and is discussed in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.12 of Exhibit Wolfram-2.

A. This adjustment reflects the contractual levels of expense associated with Information Technology ("IT") support services in a seven-year service contract with HP, including Oracle application and operational infrastructure support. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.13 of Exhibit Wolfram-2.

A. Consistent with Commission practice, this adjustment reflects the amortization of the costs incurred in conjunction with this base rate case. The costs are amortized over a three year period. The Commission recently approved a similar adjustment for Delta Natural Gas Company in Case No. 2010-00116 and in numerous other general rate case proceedings. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.14 of Exhibit Wolfram-2.

A. This adjustment reflects the on-going level of expenses related to Big Rivers' membership in the Midwest ISO. Big Rivers became a transmission-owning member of the Midwest ISO on December 1, 2010, thus no costs associated with Midwest ISO membership are reflected in the test year ended October 31, 2010. As a member of the Midwest ISO, Big Rivers will incur costs pursuant to certain schedules of the Midwest ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Midwest ISO Tariff"). The costs that comprise this adjustment are derived from the data provided by the Midwest ISO to Big Rivers. Per-unit costs were provided on a comprehensive basis by the Midwest ISO for the schedules associated with the Midwest ISO's administrative costs. These include the following:

1. **Schedule 10 and Schedule 10-FERC - ISO Cost Recovery Adder and FERC Annual Charges Recovery.** These schedules provide for the recovery by the Midwest ISO of the cost of building and operating the Midwest ISO's control center, coordinated regional transmission planning, administering the Midwest ISO Tariff, and any deferred pre-operating costs and recovery of the annual assessments paid to the FERC by the Midwest ISO.
2. **Schedule 16 - Financial Transmission Rights ("FTR") Administrative Service Cost Recovery Adder.** This schedule provides for the recovery of Energy and Operating Reserve Market costs related to bilateral trading coordination, FTR administration, FTR software tools, simultaneous feasibility analysis, revenue distribution, and FTR administration.
3. **Schedule 17 - Energy Market Support Cost Recovery Adder.** This schedule provides for the recovery of Energy and Operating Reserve Market costs related to market modeling and scheduling, market bidding, locational marginal pricing coordination, market settlements and billing, market monitoring functions, and

the economic dispatch of generating resources to serve load in the Midwest ISO footprint while establishing a spot energy market.

Costs associated with Schedule 23 - Recovery of Schedule 10 and Schedule 17 Costs from Grandfathered Agreements ("GFAs") are included in the costs above.

Big Rivers will be subject to other charges (or credits) pursuant to the Midwest ISO Tariff. The adjustment does not include cost estimates for other Midwest ISO-related costs, including Schedule 24 - Local Balancing Authority Cost Recovery, Schedule 26 - Network Upgrade from Transmission Expansion Plans, charges for Revenue Sufficiency Guarantee ("RSG"), Revenue Neutrality Uplift ("RNU"), or other Midwest ISO-related charges or credits. Projections for RSG, RNU, and other operation costs were not provided to Big Rivers by the Midwest ISO. The proposed pro forma adjustment is limited to the administrative charges associated with Big Rivers' membership in the Midwest ISO for 2011, as provided to Big Rivers by the Midwest ISO.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.15 of Exhibit Wolfram-2.

A. This adjustment annualizes the interest expense on long-term debt outstanding as of October 31, 2010, at interest rates in effect at that time. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.16 of Exhibit Wolfram-2.

A. This adjustment removes the office space rental costs associated with the Soaper Building incurred during the test year. To accommodate staffing increases following the Unwind Transaction, Big Rivers leased office space in the Soaper Building while its headquarters building was being remodeled. These costs are non-recurring. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.17 of Exhibit Wolfram-2.

A. Big Rivers had an agreement with LG&E Energy Marketing Inc. ("LEM") to provide dispatch services for the Big Rivers generation fleet upon the closing of the Unwind Transaction. This was discussed during the Unwind Proceeding. The contract terminated simultaneously with Big Rivers' integration into the Midwest ISO, which now provides dispatch services for the Big Rivers generation fleet. Effective December 1, 2010, the Midwest ISO now provides dispatch services for the Big Rivers generation portfolio. The LEM Dispatch costs incurred in the test years are non-recurring on a prospective basis. Accordingly, this adjustment is proposed to remove the LEM dispatch costs from the test year expenses.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.18 of Exhibit Wolfram-2.

A. Big Rivers has a contract with ACES Power Marketing, Inc. ("APM") to provide Big Rivers with energy risk management and trading services. Pursuant to that contract, the costs for these services increased as of January 1, 2011.

Q. What is APM?

A. APM is a firm that was founded as the Alliance for Cooperative Energy Services Power Marketing to provide wholesale power cooperatives with energy risk management and trading services. APM supplies a broad suite of energy trading and risk management services to power supply cooperatives and to numerous energy industry participants in every energy market region of the country. Big Rivers is one of 17 member/owners of APM.

Q. What services does APM provide to Big Rivers?

A. APM provides the following services to Big Rivers:

1. Trading and Counterparty Controls and Risk Policies
2. Portfolio Management and Operations
3. Settlements
4. Portfolio Modeling and Risk Analytics
5. Consulting and Other Services

The fees for these services are effective January 1, 2011. While some of these APM costs were not incurred during the test year, they are contractually specified and thus are known and measurable on a prospective basis.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.19 of Exhibit Wolfram-2.

A. This adjustment has three components. All three components are related to accounting entries made during the test year to "true up" issues associated with the closing of the Unwind Transaction. All three components reflect non-recurring items. The first component removes lease-related income recorded in Income From Leased Property (Net). The second component removes items recorded in Non-Operating Income (Net) and Extraordinary Items. The third component removes the labor-related expense recorded in Extraordinary Items. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.20 of Exhibit Wolfram-2.

A. This adjustment reflects the fact that Big Rivers recently terminated its Southeastern Federal Power Customers membership as a cost-cutting measure. The costs for this membership incurred in the test period are thus non-recurring and should be removed. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.21 of Exhibit Wolfram-2.

A. This adjustment reflects the amortization of costs incurred by Big Rivers during the test year associated with the *Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc.*, in Case No. 2010-00043 and FERC Docket Nos. ER11-15-000 and ER11-16-000. The costs associated with these proceedings are non-recurring and are amortized over a three year period. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.22 of Exhibit Wolfram-2.

A. As previously noted, the Smelter Agreements specify a TIER Adjustment Charge in Section 4.7. During the test year, the calculation placed the Smelters at the top of the "bandwidth" established in the Smelter Agreements in Section 4.7.5 and described by Mr. Seelye in his Direct Testimony. This adjustment reflects the effect of moving the Smelters from the top of the TIER Adjustment Charge bandwidth to the midpoint of the bandwidth. This adjustment was prepared by Mr. Seelye and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.23 of Exhibit Wolfram-2.

A. This adjustment eliminates advertising expenses pursuant to 807 KAR 5:016 that are institutional and promotional in nature. The adjustment also eliminates lobbying expenses, donations, penalties and economic development expenses from the test year, consistent with Commission practice. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.24 of Exhibit Wolfram-2.

A. This adjustment reflects the prospective level of income taxes for Big Rivers. The adjustment removes all federal income tax expenses from the test period. While Big Rivers anticipates having no federal income tax liability beyond 2011, it will continue to make several state tax filings and incur minimal state income tax expenses in connection with its APM membership. This adjustment was prepared by Mr. Hite and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.25 of Exhibit Wolfram-2.

A. This adjustment eliminates expenses associated with outside / professional services that were incurred in the test year that exceed the level of expenses anticipated for these services on a going-forward basis. This adjustment was prepared by Mr. Blackburn and is discussed in his Direct Testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 2.26 of Exhibit Wolfram-2.

A. This adjustment reflects the commitment of Big Rivers to implement Energy Efficiency Programs, as outlined in the Big Rivers 2010 Integrated Resource Plan. This adjustment was prepared by Mr. Blackburn and is discussed in his Direct Testimony.

VI. CONCLUSION

Q. Do you have any closing comments?

A. Yes. The current rates for Big Rivers do not provide sufficient revenues for achieving the TIER target and indeed even for recovering its costs. For the twelve months ended October 31, 2010, Big Rivers has a revenue deficiency of $39,952,926. In this post-

Unwind environment, a base rate increase is simply necessary in order for Big Rivers to adequately recover its costs. The rates proposed in this filing should be approved by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit Wolfram-1

Qualifications of
John Wolfram

QUALIFICATIONS OF JOHN WOLFRAM

Summary of Qualifications

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

Employment

The Prime Group, LLC — March 2010 - Present
Senior Consultant

Provides consulting services in the areas of tariff development, regulatory analysis, revenue requirements, cost of service, rate design, and other utility regulatory areas.

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

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and/or Boards of Directors for numerous electric and gas utilities.

E.ON U.S., LLC , Louisville, KY — 1997 - 2010
(Louisville Gas & Electric Company and Kentucky Utilities Company)
Director, Customer Service & Marketing (2006 - 2010)
Manager, Regulatory Affairs (2001 - 2006)
Lead Planning Engineer, Generation Planning (1998 - 2001)
Power Trader, LG&E Energy Marketing (1997 - 1998)

PJM INTERCONNECTION, LLC, Norristown, PA — 1990 - 1993; 1994 - 1997
Project Lead - PJM Wholesale Energy Market Information System

CINCINNATI GAS & ELECTRIC COMPANY, Cincinnati, OH — 1993 - 1994
Electrical Engineer - Energy Management System

Education

Bachelor of Science Degree in Electrical Engineering, University of Notre Dame, 1990
Master of Science Degree in Electrical Engineering, Drexel University, 1997

Associations

Member of the Institute of Electrical and Electronics Engineers (IEEE)
Member, IEEE Power Engineering Society

Expert Witness Testimony

FERC: Submitted remarks and served on expert panel in FERC Docket No. RM01-10-000 on May 21, 2002 in Standards of Conduct for Transmission Providers staff conference, regarding proposed rulemaking on the functional separation of wholesale transmission and bundled sales functions for electric and gas utilities.

Kentucky: Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2002-00029 regarding a Certificate of Public Convenience and Necessity for the acquisition of two combustion turbines.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2002-00381 regarding a Certificate of Public Convenience and Necessity for the acquisition of four combustion turbines.

Presented company position for Louisville Gas & Electric Company and Kentucky Utilities Company at public meetings held in Case Nos. 2005-00142 and 2005-00154 regarding routes for proposed transmission lines.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2005-00162 regarding the 2005 Joint Integrated Resource Plan.

Submitted discovery responses for Kentucky Utilities in Case No. 2005-00405 regarding the transfer of a utility hydroelectric power plant to a private hydroelectric power developer.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2005-00467 and 2005-00472 regarding a Certificate of Public Convenience and Necessity for the construction of transmission facilities.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2007-00067 for approval of a proposed Green Energy program and associated tariff riders.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2007-00319 for the review, modification, and continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Administrative Case No. 2007-00477 regarding an investigation of the energy and regulatory issues in Kentucky's 2007 Energy Act.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2008-00148 regarding the 2008 Joint Integrated Resource Plan.

Submitted discovery responses for Kentucky Utilities and/or Louisville Gas & Electric Company in various customer inquiry matters, including Case Nos. 2009-00421, 2009-00312, and 2009-00364.

Submitted direct testimony for Louisville Gas & Electric Company in Case No. 2009-00548 and for Kentucky Utilities Company in Case No. 2009-00549 for adjustment of electric and gas base rates, in support of a new service offering for Low Emission Vehicles, revised special charges, and company offerings aimed at assisting customers or enhancing customer service.

Virginia: Submitted direct testimony for Kentucky Utilities Company d/b/a Old Dominion Power in Case No. PUE-2002-00570 regarding a Certificate of Public Convenience and Necessity for the acquisition of four combustion turbines.

Exhibit Wolfram-2

Revenue Requirements Analysis

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Calculation of Revenue Requirement
Based on Revenues and Expenses

Line No.	Description	Reference Schedule (1)	Witness (2)	Revenue (3)	Expense (4)	Margin (Deficit) (5)
1	**Total Per Books**					
2	Total Operating Revenues & Patronage Capital			$ 522,923,675		$ 522,923,675
3	Total Cost of Electric Service				$ 527,945,092	(527,945,092)
4	Interest Income			401,668.08		401,668
5	Other Non-Operating Income (Net)			1,703,337		1,703,337
6	Other Capital Credits/Patronage Dividends			22,965		22,965
7	Extraordinary Items			(6,794,566)		(6,794,566)
8	Total Per Books			$ 518,257,079	$ 527,945,092	$ (9,688,013)
9						
10	**Adjustments**					
11	To annualize revenue & expenses for new industrial customer	2.01	Wolfram	$ 149,752	$ 110,607	$ 39,145
12	To adjust mismatch in fuel cost recovery	2.02	Wolfram	(107,815,177)	(110,040,523)	2,225,346
13	To eliminate Environmental Surcharge	2.03	Wolfram	(22,834,232)	(23,467,791)	633,559
14	To reflect temperature normalized sales volumes	2.04	Seelye	(421,610)	(295,293)	(126,318)
15	To adjust for Non-FAC PPA	2.05	Wolfram	11,588,017	12,015,173	(427,156)
16	To reflect annualized depreciation expenses	2.06	Hite		6,252,651	(6,252,651)
17	To reflect increases in labor and labor overhead expenses	2.07	Hite		624,894	(624,894)
18	To reflect current interest on construction (CWIP)	2.08	Hite		515,767	(515,767)
19	To eliminate RRI Domtar Cogen Backup revenue & expenses	2.09	Hite	(1,115,159)	(2,086,416)	971,257
20	To reflect levelized production O&M expenses	2.10	Berry		5,660,678	(5,660,678)
21	To reflect levelized planned outage expenses	2.11	Berry		2,726,965	(2,726,965)
22	To reflect going forward IT support services	2.12	Hite		292,194	(292,194)
23	To reflect amortizaton of rate case expenses	2.13	Hite		281,719	(281,719)
24	To reflect Midwest ISO related expenses	2.14	Wolfram		5,415,000	(5,415,000)
25	To annualize interest on long-term debt	2.15	Hite		70,408	(70,408)
26	To reflect leased property (Soaper Building Rent)	2.16	Hite		(128,368)	128,368
27	To adjust for costs related to LEM Dispatch	2.17	Wolfram		(936,815)	936,815
28	To adjust for costs related to APM	2.18	Wolfram		205,090	(205,090)
29	To eliminate WKEC Lease Expenses	2.19	Hite		149,673	(149,673)
30	To eliminate WKEC Unwind-related Expenses (Non-Labor)	2.19	Hite		2,357,097	(2,357,097)
31	To eliminate WKEC Unwind-related Expenses (Labor-related)	2.19	Hite		(7,476,583)	7,476,583
32	To eliminate costs for SFPC membership	2.20	Hite		(180,775)	180,775
33	To adjust for Midwest ISO Case-related expenses	2.21	Hite		(771,118)	771,118
34	To adjust for Smelter TIER Adjustment Charge	2.22	Seelye	$ (7,128,947)	-	(7,128,947)
35	To eliminate advertising, lobbying, donation and econ dev	2.23	Hite		(507,216)	507,216
36	To reflect going forward level of income taxes	2.24	Hite		183,084	(183,084)
37	To reflect going forward level of Outside Services	2.25	Blackburn		(1,000,000)	1,000,000
38	To reflect commitment to Energy Efficiency Programs	2.26	Blackburn		1,000,000	(1,000,000)
39	Total			(127,577,357)	(109,029,897)	$ (18,547,460)
40						
41						
42	**Adjusted Net Margin (Deficit)**			$ 390,679,722	$ 418,915,195	$ (28,235,473)

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Calculation of Revenue Requirement
Based on Revenues and Expenses

Line No.	Description	Reference		Amount
1	Contract TIER Target			1.24
2	Interest on Long Term Debt	Income Statemt	$	47,693,118
3	Adjusted Net Margin(Deficit) before Conventional TIER	Page 1, Line 40	$	(28,235,473)
4	Interest Income on Transition Reserve	Acct 419.040	$	271,105
5	Adjusted Net Margin(Deficit) before Contract TIER	Line 3 - Line 4	$	(28,506,579)
6	Margins Required for Contract TIER	Line 2 x (Line 1 - 1)	$	11,446,348
7	Margins Required for Conventional TIER	Line 4 + Line 6	$	11,717,454
8	**Revenue Deficiency for Contract TIER**	Line 6 - Line 5	$	39,952,927
9	Contract TIER	1 + (Line 6 / Line 2)		1.24
10	Conventional TIER	1 + (Line 7 / Line 2)		1.25

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

New Industrial Customer

	Kenergy - Equality Mine	Reference		Amount
1	Historical Test Year Revenue		$	252,566
2	Number of Months Served			7.5
3	Number of Months in Test Year			12
4	Annualization Factor	Line 3 / 4		1.59
5	Annualized Revenue	Line 1 x 4	$	402,318
6	**Revenue Adjustment**	Line 5 - 1	**$**	**149,752**
7	Operating Ratio	Line 16		0.74
8	**Expense Adjustment**	Line 6 x 7	**$**	**110,607**
9	Net Revenue Adjustment		$	39,145
	Calculation of Electric Operating Ratio			
10	Total Electric Operating Expenses		$	445,926,841
11	Less Wages and Salaries		$	58,335,396
12	Less Pensions and Benefits		$	169,663
13	Less Regulatory Commission Expense		$	1,188,958
14	Net Expenses		$	386,232,825
15	Total Electric Operations Revenues (as billed)		$	522,923,675
16	Operating Ratio	Line 14 / 15		0.74

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Mismatch in Fuel Cost Recovery

	Expense Month	Revenue Form A Page 4 of 4 Line 3	Expense Form A* Page 4 of 4 Line 8
	(1)	(2)	(3)
1	Nov-09	$ 7,995,463	$ 11,342,854
2	Dec-09	$ 10,752,262	$ 10,543,294
3	Jan-10	$ 10,953,639	$ 9,216,832
4	Feb-10	$ 7,977,788	$ 9,472,870
5	Mar-10	$ 9,603,323	$ 7,654,229
6	Apr-10	$ 7,103,469	$ 7,758,148
7	May-10	$ 8,209,595	$ 7,862,783
8	Jun-10	$ 8,282,772	$ 8,328,439
9	Jul-10	$ 8,706,972	$ 9,423,114
10	Aug-10	$ 9,529,964	$ 9,913,397
11	Sep-10	$ 8,783,754	$ 10,180,464
12	Oct-10	$ 9,916,176	$ 8,344,099
13	Total	$ 107,815,177	$ 110,040,523
14	Adjustment	$ (107,815,177)	$ (110,040,523)

* NOTE: Expenses are recovered in the succeeding month.
For example, April 2010 would be reflected in May 2010.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Environmental Surcharge Revenues and Expenses

Expense Month	Member Revenues Environmental Compliance Plans	Smelter Revenues Environmental Compliance Plans	Total Revenues Environmental Compliance Plans (Col 1 + 2)	Expenses Environmental Compliance Plans
(1)	(2)	(3)	(4)	(5)
Nov-09	$ 481,552	$ 1,120,784	$ 1,602,336	1,761,826
Dec-09	$ 678,078	$ 1,304,835	$ 1,982,913	1,799,940
Jan-10	$ 667,170	$ 1,202,362	$ 1,869,532	1,707,525
Feb-10	$ 533,068	$ 1,016,209	$ 1,549,277	1,791,649
Mar-10	$ 536,532	$ 1,280,007	$ 1,816,539	2,034,204
Apr-10	$ 511,874	$ 1,362,195	$ 1,874,069	1,784,561
May-10	$ 555,887	$ 1,332,881	$ 1,888,768	1,901,895
Jun-10	$ 696,105	$ 1,306,983	$ 2,003,088	2,165,720
Jul-10	$ 798,624	$ 1,465,881	$ 2,264,505	2,153,531
Aug-10	$ 766,535	$ 1,410,985	$ 2,177,520	2,117,812
Sep-10	$ 590,052	$ 1,286,489	$ 1,876,541	1,980,238
Oct-10	$ 525,217	$ 1,403,927	$ 1,929,144	2,268,890
Total	$ 7,340,694	$ 15,493,538	$ 22,834,232	$ 23,467,791
Adjustment	$ (7,340,694)	$ (15,493,538)	$ (22,834,232)	$ (23,467,791)

NOTE: Expenses are recovered in the succeeding month.
For example, April 2010 would be reflected in May 2010.

Expenses from ES Form 1.10, Net Jurisdictional Pollution Control Operating Expenses less Proceeds from By-Product and Allowance Sales

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Temperature Normalization

#	Item	Temperature Normalization Adjustment with Banding
(1)	Normalization Adjustment - kWh	(20,667,174)
(2)	Rural Charge per kWh	$ 0.0204
(3)	**Revenue Adjustment**	**$ (421,610)**
(4)	Base Fuel and Variable Cost per kWh	$ 0.01429
(5)	**Expense Adjustment**	**$ (295,293)**
(6)	Net Adjustment	$ (126,318)

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Non-FAC Purchased Power Adjustment (PPA) and Expenses

	Expense Month	Member Non-FAC PPA Deferral Charged/(Credited)	Smelter Non-FAC PPA Charged/(Credited)	Total Non-FAC PPA Charged/(Credited)	Non-FAC PPA Purchased Power Expenses
	(1)	(2)	(3)	(4)	(5)
1	Nov-09	23,639	55,018	78,657	(574,927)
2	Dec-09	(221,241)	(425,738)	(646,979)	(1,564,065)
3	Jan-10	(579,883)	(1,045,055)	(1,624,938)	(400,072)
4	Feb-10	(124,905)	(238,112)	(363,017)	(1,069,268)
5	Mar-10	(320,168)	(763,825)	(1,083,993)	(1,091,842)
6	Apr-10	(274,696)	(731,019)	(1,005,715)	(524,547)
7	May-10	(163,364)	(391,706)	(555,070)	(493,018)
8	Jun-10	(180,483)	(338,869)	(519,352)	(784,401)
9	Jul-10	(289,208)	(530,844)	(820,052)	(801,330)
10	Aug-10	(285,284)	(525,132)	(810,416)	(3,037,728)
11	Sep-10	(1,056,021)	(2,127,507)	(3,183,528)	(1,244,616)
12	Oct-10	(331,294)	(722,320)	(1,053,614)	(429,359)
13	Total	(3,802,908)	(7,785,109)	(11,588,017)	(12,015,173)
	Adjustment	3,802,908	7,785,109	11,588,017	12,015,173

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Depreciation Expense

1	Proforma Year - "New" Rates	42,532,089
2	Historical Year	36,279,438
3	**Proforma Adjustment**	**6,252,651**

Description: Annualized depreciation expense on utility plant at October 31, 2010, including construction work in progress, per the 2010 depreciation study rates.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Labor & Labor Overheads Expenses

1	Proforma Year	68,708,897
2	Historical Year	68,084,003
3	Proforma Adjustment	624,894

Description: The proforma amount of $68,709,897 for labor/labor overheads includes employees of record as of December 31, 2010, excluding those on long-term disability (LTD) for whom replacements have been hired. This results in a total of 606 employees, 249 non-bargaining and 357 bargaining. As appropriate, base labor includes step increases and contract increases for the bargaining employees, and qualification increases for non-bargaining employees. Shift premiums were appropriately included. Overtime pay was based upon the amount currently expected for 2011. The most current information available was used to determine labor overhead cost (FICA, FUTA, SUTA, workers compensation, retirement/401(k), life, LTD, dental and medical, post-employment and post-retirement costs, including the most recent premium rates available, and the most recent FAS 87 and 106 estimates. No incentive pay or bonus pay is incuded in the proforma amount.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Interest on Construction Work In Progress

1	Proforma Year	0
2	Historical Year	(515,767)
3	Proforma Adjustment	515,767

Description: To reflect current interest on construction work in progress (CWIP)

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

RRI Domtar Cogen Backup Revenues & Expenses

	Expense Month	Domtar Cogenerator Backup Revenues provided under RRI Contract	RRI Incremental Interim Energy Revenue	Total Revenue Derived from the RRI Contract (Line 2 + 3)	RRI Reservation Fee & Purchased Power Expenses
	(1)	(2)	(3)	(4)	(5)
1	Nov-09	358,314	7,207	365,521	448,214
2	Dec-09	68,467	46,123	114,590	158,367
3	Jan-10	299,757	3,537	303,294	389,657
4	Feb-10	0	0	0	89,900
5	Mar-10	1,359	5,398	6,756	91,259
6	Apr-10	0	0	0	89,900
7	May-10	73,226	14,728	87,954	163,126
8	Jun-10	0	0	0	89,900
9	Jul-10	0	0	0	89,900
10	Aug-10	57,191	11,660	68,851	147,091
11	Sep-10	0	0	0	89,900
12	Oct-10	149,302	18,891	168,193	239,202
13	Total	1,007,616	107,543	1,115,159	2,086,416
14	Adjustment	(1,007,616)	(107,543)	(1,115,159)	(2,086,416)

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Production Fixed O&M Expenses, Excluding Planned Outage Expenses

1	Proforma Year	$	38,877,546
2	Historical Year		33,216,868
3	Proforma Adjustment		5,660,678

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Planned Outage Expenses

1	Proforma Year	$	14,437,513
2	Historical Year		11,710,548
3	Proforma Adjustment		2,726,965

Description: During the historical test period, Big Rivers' planned outage expenses were lower than both historical and forecast planned outage expenses. Accordingly, this proforma adjustment serves to normalize planned outage expenses.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Information Technology (IT) Support Services

1	Proforma Year	2,189,242
2	Historical Year	1,897,048
3	Proforma Adjustment	292,194

Description: Big Rivers has outsourced Oracle application support (software) and Oracle operational infrastructure (hardware, servers, firewalls, switches, helpdesk, etc.). Oracle software (R12 - eBusiness suite) was chosen as Big Rivers' application software, and engaged HP (formally EDS) for implementation and to provide on-going administrative support. This decision was made to expedite transitioning from the two former business information systems of WKEC and Big Rivers to the new system for Big Rivers. Big Rivers has executed a seven year service contract with HP for Oracle application and infrastructure support. The HP agreement enables Big Rivers to have a known cost for its business information systems.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Rate Case Expenses

1	Proforma Year	299,643
2	Historical Year	17,924
3	Proforma Adjustment	281,719

Description:

To normalize the legal and consulting costs anticipated to be incurred by the Company in connection with this general rate case before the KPSC, one-third of $898,930, or $299,643. Note that this estimated cost includes the cost of service and rate design study and the depreciation study. During the test year, expense of $17,924 was incurred in connection with the cost of service and rate design study and the depreciation study.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Midwest ISO (Member) Cost

1	Proforma Year	5,415,000
2	Historical Year	0
3	Proforma Adjustment	5,415,000

Description: Big Rivers integration into Midwest ISO took place on December 1, 2010. Big Rivers is now subject to the Midwest ISO's charges assessed under the Midwest ISO Tariff Schedules 10, 16 and 17.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Interest Expense on Long-Term Debt

1	Proforma Year	$	47,693,118
2	Historical Year		47,622,709
3	Proforma Adjustment		70,408

Description: To annualize interest expense on long-term debt outstanding at 10/31/10 at interest rates in effect at that time.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Leased Property (Soaper Building Rent)

1	Proforma Year	0
2	Historical Year	128,368
3	Proforma Adjustment	(128,368)

Description: To remove all office space rental costs associated with the Soaper Building incurred during the test year. Post-Unwind, while Big Rivers' headquarters building was being remodeled to accommodate the increased staff headcount, this office space was leased.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

LEM Dispatch Fees

1	Proforma Year	0
2	Historical Year	936,815
3	Proforma Adjustment	(936,815)

Description: Big Rivers entered into a contract with LEM upon the closing of the Unwind Transaction to provide dispatch services for its generation fleet. This contract terminated simultaneously with Big Rivers integration into MISO. Effective December 1, 2010, MISO now provides dispatch services for Big Rivers' generation fleet. Accordingly, this proforma adjustment serves to remove such costs.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

APM Fees

1	Proforma Year	2,003,132
2	Historical Year	1,798,042
3	Proforma Adjustment	205,090

Description: ACES Power Marketing (APM) provides the following services to Big Rivers: 1. Trading and Counterparty Controls and Risk Policies; 2. Portfolio Management and Operations; 3. Settlements; 4. Portfolio Modeling and Risk Analytics; 5. Consulting and Other Services. These APM fees are effective January 1, 2011.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

WKEC Unwind "True-Up"

WKEC Lease Income

1	Proforma Year	0
2	Historical Year	(149,673)
3	Proforma Adjustment	149,673

Description: To remove non-recurring WKEC lease related income.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

WKEC Unwind "True-Up" (continued)

WKEC Non-Operating Items (Non-Labor)

1	Proforma Year	0
2	Historical Year	(2,357,097)
3	Proforma Adjustment	2,357,097

Description: To remove non-recurring WKEC non-operating income and the non-labor related portion of the extraordinary gain.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

WKEC Unwind "True-Up"
(continued)

WKEC Non-Operating Items (Labor-related)

1	Proforma Year	0
2	Historical Year	7,476,583
3	Proforma Adjustment	(7,476,583)

Description: Remove the post-retirement medical true-up (i.e. labor related expense recorded as extraordinary gain item) related to the Unwind transaction from the historical test year.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Southeastern Federal Power Customers Membership

1	Proforma Year	0
2	Historical Year	180,775
3	Proforma Adjustment	(180,775)

Description: Big Rivers has recently terminated its Southeastern Federal Power Customers membership. Accordingly, this proforma adjustment serves to remove the associated cost from the test year.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Midwest ISO Case

1	Proforma Year	534,259
2	Historical Year	1,305,377
3	Proforma Adjustment	(771,118)

Description: To remove two-thirds of the Midwest ISO Case legal, consulting and misc. costs incurred during the test year associated with the *Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent System Operator, Inc.*, Case No. 2010-00043, and FERC Docket Nos. ER11-15-000 and ER11-16-000.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Smelter TIER Adjustment Charge

1	Proforma Year	$	7,114,653
2	Historical Year		14,243,600
3	Proforma Adjustment		(7,128,947)
4	Century Historical Year Amount		8,076,959
5	Alcan Historical Year Amount		6,166,641
6	Total		14,243,600
7	Percentage Reduction from Top of Bandwidth		50%
8	Century Contract Amount	$	4,034,427
9	Alcan Contract Amount	$	3,080,226
10	Total	$	7,114,653

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Promotional / Institutional Advertising, Lobbying, Donations and Economic Development

1	Proforma Year	0
2	Historical Year	507,216
3	Proforma Adjustment	(507,216)

Description: To remove all promotional/institutional advertising expenses, political/lobbying expenses, donations, penalties and economic development expenses from the test year.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Income Taxes

1	Proforma Year	885
2	Historical Year	(182,199)
3	Proforma Adjustment	183,084

Description: To remove all but $885 for minimal tax payments to several states. While Big Rivers, a non-exempt cooperative, anticipates having no federal tax liability for 2012, it will continue to make several state tax filings and incur minimal state income tax in connection with its ACES Power Marketing membership.

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Outside / Professional Services

1	Proforma Year	1,712,026
2	Historical Year	2,712,026
3	Proforma Adjustment	(1,000,000)

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Energy Efficiency Programs

1	Proforma Year	1,000,000
2	Historical Year	0
3	Proforma Adjustment	1,000,000

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

DIRECT TESTIMONY

OF

ROBERT W. BERRY
VICE PRESIDENT, PRODUCTION

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
ROBERT W. BERRY

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DIRECT TESTIMONY
OF
ROBERT W. BERRY

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Robert W. Berry. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson Kentucky, 42420 as its Vice President of Production. I have held this position since July 2009 upon the closing of the transaction that unwound Big Rivers' 1998 lease with E.ON U.S., LLC and its affiliates (the "Unwind Transaction"), described in Case No. 2007-00455. Prior to the closing of the Unwind Transaction, I was employed by Western Kentucky Energy for 11 years beginning as a Maintenance Manager in 1998. I held the position of Plant Manager of the Coleman Generating Station from 2000 until 2003 at which time I became the Plant Manager of the Sebree Generating Station. Altogether, I have over 30 years of experience in this system, having worked for both Big Rivers and Western Kentucky Energy.

Q. Have you previously testified before this Commission?

A. Yes, I testified on behalf of Big Rivers in the Unwind proceeding, Case No. 2007-00455.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (i) describe Big Rivers generating system and the performance of the generating units, and (ii) support certain Pro Forma Adjustments to Test Year Revenues or Expenses.

Q. Please summarize your testimony.

A. While the reliability of the Big Rivers generating facilities has been excellent, it is imperative that Big Rivers perform adequate maintenance on the units. During the test year, Big Rivers was required to defer maintenance projects and reduce maintenance expenses to meet the financial covenants in its loan documents. While the level of spending on maintenance during the test year was adequate on a short-term basis, it is imprudent on a longer-term basis. Big Rivers must return to a sustainable level of maintenance expenditures; otherwise, plant reliability will suffer, increasing forced outages, repair costs, and purchase power expenses. We are requesting pro forma adjustments in this proceeding to provide for the inclusion of a prudent level of maintenance costs. However, even if Big Rivers receives the full amount of the requested adjustments relating to maintenance costs, if it does not receive the full rate increase it is seeking, the only option available to Big Rivers to meet the required margin for interest ratio ("MFIR") and maintain credit ratings as required in its long-term debt agreements would be to reduce expenses, including plant maintenance, which would have an adverse impact on reliability and ultimately increase costs to Big Rivers.

III. PLANT PERFORMANCE

Q. Please describe Big Rivers' production resources.

A. Big Rivers currently owns and operates 1,444 MW of generating capacity in four stations: (i) Kenneth W. Coleman (443 MW) in Hawesville, KY; (ii) Robert A. Reid (130 MW) in Robards, KY; (iii) Robert D. Green (454 MW) in Robards, KY; and (iv)

D. B. Wilson (417 MW) in Centertown, KY. An additional 385 MW are available from Henderson Municipal Power and Light ("HMP&L") (207 MW) and from the Southeastern Power Administration ("SEPA") (178 MW), for a total capacity availability of 1,829 MW.

Q. **Has the HMP&L capacity amount changed since Big Rivers produced its 2009 Annual Report?**

A. Yes. In the 2009 Annual Report that is provided in Tab 36 pursuant to 807 KAR 5:001 Section 10(6)(q), the Big Rivers share of the Station Two capacity was 212 MW. In the 2011 Integrated Resource Plan ("IRP") filed on November 12, 2010, Big Rivers noted that it has rights to 207 MW of HMP&L's William L. Newman Station Two facility ("HMP&L Station Two"). HMP&L has the contractual right to increase or decrease its capacity reservation from HMP&L Station Two by up to 5 MW each year. For 2010, HMP&L exercised that right, reducing Big Rivers' share of HMP&L Station Two from 212 MW to 207 MW.

Q. **Please describe the overall reliability of the Big Rivers generation system during the twelve months ended October 31, 2010.**

A. Overall, the Big Rivers generating fleet was very reliable during the 12-month test period and indeed since the closing of the Unwind Transaction in July 2009. This validates Big Rivers' assessment of the condition of the generating units at the closing of the Unwind Transaction. However, if Big Rivers is unable, because of its financial condition, to perform adequate maintenance on the units, the reliability of the units will suffer.

Q. **How does Big Rivers benchmark the reliability of its generation performance relative to others in the industry?**

A. A commonly used industry standard for measuring the reliability of coal-fired generating units is the weighted average Equivalent Forced Outage Rate ("EFOR").

Big Rivers determines EFOR for its generation system using the North American Electric Reliability Council's ("NERC") Generator Availability Data System ("GADS"), and can compare its EFOR against that of other utilities. Big Rivers can also rely on Equivalent Availability Factor ("EAF") and Net Capacity Factor ("NCF") for making comparisons to other utilities in the industry.

Q. How does Big Rivers' generation reliability compare to others on EFOR, EAF and NCF?

A. Big Rivers uses Navigant Consulting's "Generation Knowledge Service" to compare its plant reliability to similar units across the region. In a benchmarking study completed in January 2011, for the period beginning January 2007 through September 2010, the performance statistics for Big Rivers' units were better than the median for the ninety nine (99) units in the peer group. For the comparative period, the performance metrics for Big Rivers' units compared to the peer group median are as follows:

Big Rivers Units		**Peer Group Median**	
EFOR	4.37%	EFOR	6.47% (lower is better)
EAF	89.02%	EAF	86.65% (higher is better)
NCF	81.05%	NCF	70.57%

Thus, as this NERC GADS data demonstrates, Big Rivers' generation reliability compares quite favorably to others in the industry.

Q. Did Big Rivers experience any important planned or unplanned outages at particular generating plants during the test year?

A. Yes. During the test year, Big Rivers experienced important planned outages on the Wilson Station Unit, HMP&L Station Two Unit 2, and Coleman Station Unit 2. The Wilson outage began on October 3, 2009 and the test year began on November 1, 2009; therefore, not all of the planned outage expenses for the Wilson outage were captured during the test year.

Q. Please describe the outage at the Wilson Station Unit.

A. The Wilson Unit outage began on October 3, 2009 and continued into the test year, ending on December 3, 2009. During the outage, Big Rivers completed a turbine/generator inspection and overhaul, conducted a boiler inspection and repair, replaced "B" platen superheater, performed select high energy piping and header inspections, replaced two catalyst layers in the SCR, performed a major refurbishment of the FGD, replaced the scrubber outlet duct, and made repairs to the chimney.

Q. Please describe the outage at HMP&L Station Two Unit 2.

A. The HMP&L Station Two Unit 2 outage began on April 2, 2010 and continued through April 23, 2010. During the outage, Big Rivers completed boiler inspection and repairs, performed select high energy piping and header inspections, replaced fill in the cooling tower, made miscellaneous pump, valve, and piping repairs, and repaired various air and gas ducts.

Q. Please describe the outage at the Coleman Station Unit 2.

A. The Coleman Station Unit 2 outage began on October 2, 2010 and was completed on October 30, 2010. During the outage, Big Rivers completed a turbine valve inspection and overhaul, conducted a boiler inspection and repairs, performed select high energy piping and header inspections, made miscellaneous pump, valve and piping repairs, made repairs to the FGD and booster fan, and repaired various air and gas ducts.

Q. Were there any other significant generation outages, either planned or unplanned?

A. No. During the test year, there were several unplanned outages within Big Rivers' generating fleet; however, none were significant.

Q. How do the costs of generation unit outages during the test year compare to historical and anticipated future levels?

A. During the test period, Big Rivers' planned outage expenses were lower than both historical and forecast levels of planned outage expenses. The lower than normal outage expense during the test year is a result of Big Rivers deferring scheduled outages so that the Company could achieve at least the 1.10 MFIR required by its loan covenants. Please refer to Mr. C. William Blackburn's testimony for a more detailed explanation of the loan covenant requirements. The historical five-year outage expense (2006-2010) is $14 million per year compared to the $11.7 million experienced during the test year.

Q. Did Big Rivers defer any significant planned unit outages during the test year?

A. Yes. In 2010, Big Rivers deferred $3.1 million of scheduled outages, including maintenance on its Green Station Unit 1. As a result of Big Rivers deferring maintenance that was initially planned to occur in 2010 to 2011, it became necessary for Big Rivers to also defer $12.4 million of scheduled outages initially planned for 2011 so that the scheduled outages deferred from 2010 could be performed in 2011 and Big Rivers could still achieve the MFIR necessary to meet its loan covenants.

Q. Why did Big Rivers defer maintenance outages during this timeframe?

A. Due to the depressed economy during this period, load demand on the Big Rivers system was down, off system sales volumes were low and market prices were down. Big Rivers deferred maintenance activities during this time period in order to reduce expenses and meet its loan covenants.

Q. Since the Big Rivers generation system performed so well during the test year, can Big Rivers continue with test year levels for scheduled outages and maintenance activities?

A. No. As shown on Exhibit Berry-1, experience has confirmed the EFOR achieved in any one year is a direct result of the planned maintenance activity performed in the previous years. Thus, although the generating units performed well during 2010, that was a direct result of the planned outages that were performed in 2008 and 2009, not the level of planned outages in 2010. The optimal number of annual planned outage hours for the Big Rivers generating system is between 3,500 hours and 4,000 hours per year. Big Rivers' five-year (2005-2009) historical average of annual planned outages is approximately 3,718 hours. The planned outage hours in 2010 and 2011 were 1,485 hours and 2,016 hours respectively, both significantly below the optimal and historical annual averages.

During the Unwind proceeding, Case No. 2007-00455, both the Kentucky Public Service Commission and the Attorney General raised concerns regarding the condition of the Big Rivers generating units and the need to have well-maintained plants. During that case, I testified before the Commission on behalf of Big Rivers confirming the units were in good condition and that there was enough money budgeted in the Unwind financial model to maintain the units to acceptable industry standards. Unfortunately, due to the depressed economy Big Rivers has been forced to deviate from those plans in order to meet its loan covenants and maintain its credit rating. In 2010 and 2011 combined, Big Rivers has deferred approximately $15.5 million in O&M expense and $18.8 million in capital expense. If Big Rivers continues with test-year levels for scheduled outages and maintenance activities, the condition of the generating units will deteriorate, Big Rivers will experience increased forced outages, repair costs will increase since they will be done more on an emergency basis than on a planned bases, and since forced outages cannot be planned to take advantage of market conditions, Big Rivers' purchased power costs will increase and its ability to generate off system sales will decrease, which will be devastating to Big Rivers' financial condition since Big Rivers' margins are derived almost exclusively from its off-system sales. Thus, if Big Rivers continues to defer maintenance activities, Big Rivers' ability to provide safe, reliable and economic power to its members will be compromised.

Q. Does Big Rivers have plans for any significant planned maintenance outages at its generating plants in the near future?

A. Yes. Over the next two years, Big Rivers plans to perform maintenance on several units, due in part to the outage deferrals in 2010 and 2011, and to return the maintenance activities to the recommended optimal maintenance schedule. In 2011, Big Rivers plans to perform significant maintenance outages on HMP&L Station Two Unit 1 and Green Station Unit 1. Plans also include less significant outages on the Wilson Unit and Green Station Unit 2. For 2012, Big Rivers plans to have significant outages on the Wilson Unit, HMP&L Station Two Unit 2, Green Station Unit 2, Coleman Station Units 1 and 3, and Reid Station Units 1 and 2. Maintenance on these units over the next two years is needed in order to provide continued safe and reliable operation of the facilities.

Q. Is it possible to shift some of the expenses in 2012 to levelize the spending?

A. No. Big Rivers is requesting the rate increase to take effect on September 1, 2011; therefore, if Big Rivers were to pull some of the 2012 projects into 2011, it would not achieve the MFIR necessary to meet its loan covenants. The planned outages scheduled in 2012 are primarily the planned outages that were deferred in 2010 and 2011; therefore, deferring them any further would not be prudent. Four of the six generating units that have planned outages scheduled in 2012 will have operated between 38 and 50 months since its last significant planned outage.

Q. What steps is Big Rivers taking to ensure the reliable, safe and economic operation of its generation facilities on a prospective basis?

A. Outage planning is an important part of Big Rivers' reliability strategy. As was described in the Unwind Proceeding, Big Rivers' normal planned outage intervals are every three years for the Coleman units and every two years for its other units. Planners at each station use Big Rivers' outage planning process manual to ensure optimum results from unit down time. Big Rivers anticipates nearly 7,500 hours of outage maintenance at an estimated cost of approximately $32 million over the next two years. By the end of 2012, the maintenance work that was deferred during 2010 and 2011 will be completed. Big Rivers also expects to spend more than $200 million in asset replacement and capital improvements over the next four years to enhance the reliability and efficiency of its power plants. These actions are necessary for Big Rivers to continue its trend of reliable, safe and economic generation portfolio performance.

IV. PRO FORMA ADJUSTMENTS

Q. Are you sponsoring any Pro Forma Adjustments to Test Year Revenues and Expenses?

A. Yes. I am sponsoring a Pro Forma Adjustment to Test Year Expenses for certain Planned Outage expense and Non-Outage O&M expense. In 2010 and 2011, Big Rivers was forced to defer certain maintenance expenses in order to achieve the MFIR needed to meet its loan covenants. These Pro Forma Adjustments are necessary to allow Big Rivers to continue to operate the power plants in a safe, reliable and efficient manner.

Q. Please describe the Pro Forma Adjustments for both the Planned Outage Expense and the Non-Outage O&M Expense.

A. Attached to my testimony is Exhibit Berry-2 which identifies the Planned Outage Pro Forma Adjustments and Exhibit Berry-3 which identifies the Non-Outage O&M Pro Forma Adjustments. The Non-Outage O&M Pro Forma includes but is not limited to items such as drying agent for wet fuel, fuel sampling, barge cargo box and walkway cleaning, stack band replacements at Wilson Station, coal conveyor maintenance at Coleman Station that was deferred in 2010, ash pond dredging at Coleman Station and additional mill overhauls at all plants. Please refer to Exhibit Berry-3 for a comprehensive list of the non-outage pro forma adjustments.

Q. What are the consequences if Big Rivers is not granted these Pro Forma adjustments?

A. Big Rivers is only requesting the funds necessary to operate the generating plants in a safe and reliable manner; therefore, if any of these Pro Forma Adjustments are not granted then Big Rivers' only option is to continue to reduce the maintenance activities at the generating stations. The reductions in maintenance activities would be necessary to reduce the maintenance expenses so that Big Rivers can achieve the MFIR necessary to meet its loan covenants. Please refer to Mr. Blackburn's testimony for a more detailed explanation of the loan covenant requirements. Continuing to reduce maintenance activities at the generating stations will create a series of issues including but not limited to poor plant reliability due to increased equipment failure, increased purchase power expense due to poor plant reliability, increased repair cost due to repairs being performed on an emergency, piecemeal basis rather than a planned basis and an overall reduction in the value of the assets.

IX. <u>CONCLUSION</u>

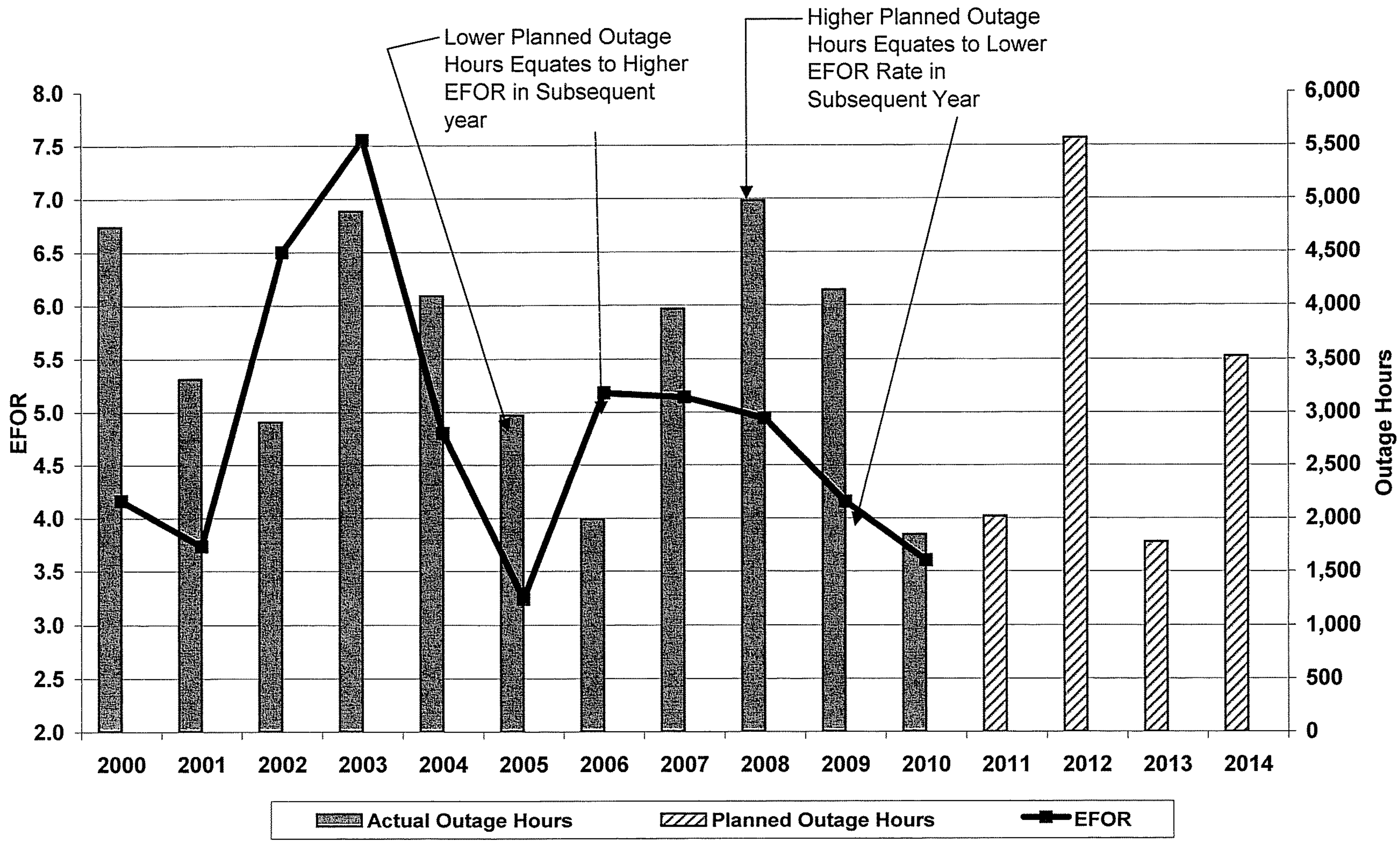
Q. Do you have any closing comments?

A. Yes. Even with all of the proposed production-related pro-forma adjustments, the average annual maintenance expense included in Big Rivers' current 2011-2014 Production Business Plan is approximately $2.3 million less than the average annual maintenance expense that was included in the financial model filed with the Kentucky Public Service Commission in the Unwind proceeding, Case No. 2007-00455. This reduction in expenses is a result of deferring outages and increasing the outage cycle times. Big Rivers needs the full amount of the requested pro-forma production expenses to operate and maintain its plants prudently in the future and to maintain the value of the generating assets.

Q. Does this conclude your testimony?

A. Yes, this concludes my testimony.

Big Rivers Electric Corporation
Case No. 2011-00036
Relationship of Planned Outage Hours to Equivalent Forced Outage Rate



Case No. 2011-00036
Exhibit Berry-1
Page 1 of 1

Big Rivers Electric Corporation
Case No. 2011-00036
Planned Outage Expenses

Description: During the historical test period, Big Rivers incurred $11,710,548 in planned outage expenses. The planned outage expenses during this period was lower than historical and planned spending over the next four years. The pro forma adjustment of $2,726,965 serves to normalize the expenses associated with planned outage expense.

Account	Test Year	2011	2012	2013	2014	Average
	11,710,548	11,710,548	11,710,548	11,710,548	11,710,548	11,710,548
502		(30,502)	9,498	(30,502)	(30,502)	(20,502)
506		(3,390)	(3,390)	(3,390)	(3,390)	(3,390)
511		173,820	1,268,669	149,783	1,265,195	714,367
512		430,355	6,773,947	2,087,264	3,876,312	3,291,970
513		(2,707,793)	(460,295)	(1,834,932)	(1,365,923)	(1,592,236)
514		166,073	655,181	102,383	707,286	407,731
553		354,100	1,200,000	-	-	388,525
555		(577,158)	1,200,527	(1,136,846)	(1,324,519)	(459,499)
		(2,194,496)	10,644,137	(666,240)	3,124,458	2,726,965
		9,516,052	22,354,685	11,044,308	14,835,006	14,437,513

Big Rivers Electric Corporation
Case No. 2011-00036
Non-Outage Operations and Maintenance Expenses

Description: During the historical test period, Big Rivers incurred $33,216,868 in non-outage O&M expenses. The non-outage O&M expenses during this period was lower than the planned spending over the next four years. The pro forma adjustment of $5,660,678 serves to normalize the expenses associated with non-outage O&M.

1		Wilson Station						
2	Non-Outage Task Description	Account	Test Year	2011	2012	2013	2014	Adjustment
3	Test Year - Non-Outage		9,218,989	9,218,989	9,218,989	9,218,989	9,218,989	9,218,989
4								
5	Adjustments:							
6	Inflation adjustment (Test Year to current)			230,475	466,711	714,616	980,385	598,047
7								
8	Mill Overhauls	512		277,000	-	295,000	-	143,000
9	Cooling Tower Structural Repairs	513		255,000	-	-	-	63,750
10	County Water Study	511		-	72,100	-	77,235	37,334
11	Plant Road Repairs (Blacktop)	511		-	100,000	50,000	51,750	50,438
12	Coal Handling Entrance & Road Repair	511		-	-	69,664	-	17,416
13	Structural Painting	511		-	43,900	45,437	46,015	33,838
14	Barge Walkway Cleaning	501		33,000	33,000	33,000	67,000	41,500
15	Barge Cargo Box Cleaning	501		75,000	-	-	-	18,750
16	Stack Band Replacement	512		350,000	360,000	-	240,000	237,500
17	Ammonia Tank and Safety Valve Inspection	512		-	-	95,000	-	23,750
18	River Dredging	501		-	-	-	165,000	41,250
19	S03 Mara Testing	506		-	-	30,000	-	7,500
20	Centac Overhaul	512		-	124,000	117,000	121,000	90,500
21	Recycle Pump Overhauls	512		39,000	41,000	168,000	174,000	105,500
22	Site Storm Drainage Sump Cleaning	511		-	-	-	50,000	12,500
23	Neuco Maintenance Contract	506		40,000	40,000	40,000	40,000	40,000
24	Barge Unloader Bucket Rebuild	512		80,000	-	80,000	-	40,000
25	Coal Conveyor Cover Replacements	512		29,000	30,000	30,000	31,000	30,000
26	Air Heater Wash Impoundment Pond Treatment	506		-	27,000	30,000	30,000	21,750
27	Nuclear Recording & Indicating devices (disposal & repair)	506		40,000	62,000	40,000	40,000	45,500
28	Misc. adjustments to Non-outage	512		(23,733)	48,612	(28,071)	37,993	8,700
29	Total Adjustments			1,424,742	1,448,323	1,809,646	2,151,378	1,708,522
30								
31	Total Wilson Non-Outage Adjusted			10,643,731	10,667,312	11,028,635	11,370,367	10,927,511
32				0	(0)	(0)	0	

Big Rivers Electric Corporation
Case No. 2011-00036
Non-Outage Operations and Maintenance Expenses

Description: During the historical test period, Big Rivers incurred $33,216,868 in non-outage O&M expenses. The non-outage O&M expenses during this period was lower than the planned spending over the next four years. The pro forma adjustment of $5,660,678 serves to normalize the expenses associated with non-outage O&M.

		Coleman Station					
Non-Outage Task Description	Account	Test Year	2011	2012	2013	2014	Adjustment
Test Year - Non-Outage		8,439,959	8,439,959	8,439,959	8,439,959	8,439,959	8,439,959
Adjustments:							
Inflation adjustment (Test Year to current)			210,999	427,273	654,229	897,540	547,510
Mill Overhauls	512		175,000	-	(175,000)	350,000	87,500
Bar Screen Inspections & Repairs	513		40,660	-	-	-	10,165
Electrical Distribution Maintenance	513		-	-	-	94,864	23,716
Deferred Conveyor Maintenance	511		526,440	521,440	521,440	521,440	522,690
Deferred Structures and Life Assessment Inspections	511		278,830	290,000	290,000	290,000	287,208
Plant Lighting	511		-	-	-	60,000	15,000
Barge Walkway Cleaning	501		35,000	35,000	35,000	35,000	35,000
Dozers or Loaders engine & transmission	501		177,917	-	-	66,833	61,188
Dry Dock Tug Boat	501		-	139,536	-	-	34,884
Unplanned outages, soot blowers, and gas leaks (no planned outage in 2011)	512		247,950	-	-	-	61,988
Ash Pond Dredging	512		296,222	292,497	341,218	423,956	338,473
FGD Maintenance	512		75,365	75,365	75,365	75,365	75,365
ROFA fan exp joints & boiler port repairs	512		111,847	73,957	73,957	73,957	83,430
Circulating Water & Intake (2012 has two outages - less money in routine)	513		180,153	-	134,562	177,323	123,010
Misc	514		10,054	31,198	(149,642)	27,098	(20,323)
Total Adjustments			2,366,437	1,886,266	1,801,129	3,093,376	2,286,802
Total Coleman Non-Outage Adjusted			10,806,396	10,326,225	10,241,088	11,533,335	10,726,761
			-	-	-	-	

Big Rivers Electric Corporation
Case No. 2011-00036
Non-Outage Operations and Maintenance Expenses

Description: During the historical test period, Big Rivers incurred $33,216,868 in non-outage O&M expenses. The non-outage O&M expenses during this period was lower than the planned spending over the next four years. The pro forma adjustment of $5,660,678 serves to normalize the expenses associated with non-outage O&M.

		Green Station					
Non-Outage Task Description	**Account**	**Test Year**	**2011**	**2012**	**2013**	**2014**	**Adjustment**
Test Year - Non-Outage		9,778,938	9,778,938	9,778,938	9,778,938	9,778,938	9,778,938
Adjustments:							
Inflation adjustment (Test Year to current)			244,473	495,059	758,020	1,039,933	634,371
Barge Cleaning / Fuel Sample Analysis	501		93,000	93,000	93,000	93,000	93,000
Fire Water Line Repairs	511		90,200	90,200	90,200	96,000	91,650
Plant Road Repairs	511		(225,000)	(200,000)	(200,000)	(100,000)	(181,250)
FGD Grating Repairs	512		(350,000)	(350,000)	(350,000)	(350,000)	(350,000)
Overhaul IU Conveyor Frames	512		(115,000)	(115,000)	(115,000)	(113,000)	(114,500)
BFP Overhaul Schedule - 2 pumps per yr.	512		-	194,000	194,000	199,000	146,750
Replace 690 Tiger Transfer Case and Tires	501		-	-	-	101,650	25,413
D9T (Engine, Transmission, Torque and Radiator)	501		-	-	114,000	-	28,500
Replace Cooling Tower Fan Blades and Hub Assembly	501		83,500	83,500	83,500	83,500	83,500
Misc	514		(61,647)	46,093	47,776	90,954	30,794
Total Adjustments			(240,474)	336,852	715,496	1,141,037	488,228
Total Green Non-Outage Adjusted			9,538,464	10,115,790	10,494,434	10,919,975	10,267,166
			(0)	(0)	(0)	0	

Big Rivers Electric Corporation
Case No. 2011-00036
Non-Outage Operations and Maintenance Expenses

Description: During the historical test period, Big Rivers incurred $33,216,868 in non-outage O&M expenses. The non-outage O&M expenses during this period was lower than the planned spending over the next four years. The pro forma adjustment of $5,660,678 serves to normalize the expenses associated with non-outage O&M.

	Reid/Station Two						
Non-Outage Task Description	Account	Test Year	2011	2012	2013	2014	Adjustment
Test Year - Non-Outage		5,778,982	5,778,982	5,778,982	5,778,982	5,778,982	5,778,982
Adjustments:							
Inflation adjustment (Test Year to current)			144,475	292,561	447,961	614,561	374,889
Drying Agent - HMPL	555(501)		212,054	203,554	195,154	186,754	199,379
Drying Agent - Reid	501		66,318	66,318	66,318	66,318	66,318
Fuel Sampling Analysis	555(501)		47,100	46,000	44,900	43,800	45,450
New D8N Engine, etc - HMPL	555(501)		45,655	-	-	-	11,414
New D8N Engine, etc - Green	501		66,434	-	-	-	16,608
New D8N Engine, etc - Reid	501		9,511	-	-	-	2,378
H0 - Clean & Paint Stack	555(512)		240,000	-	-	-	60,000
H0 - Mass Flow/Screw Feeder Repair (H1B & H2A)	555(512)		99,500	94,700	-	-	48,550
H1 - Rebuild D Circulating Water Pump	555(512)		82,900	-	-	-	20,725
H0 - Vacuum All Units	555(502)		75,000	-	-	-	18,750
R1 - OH #3 Circ Riv Water Pump	512		-	360,000	-	-	90,000
R1 - Major Conduit Repair	513		-	110,000	-	-	27,500
R1 - Rebuild #1 Barge Unloader & 3C Reclaim Feeder	512		-	120,000	-	-	30,000
H1 - OH "B" Ash Sluice Pump	555(512)		19,400	-	-	-	4,850
H1 - Rebuild H1C Scrubber Sump Pump	555(513)		7,800	-	-	-	1,950
H1 - Mass Flow Conveyor Foundation Repair	555(512)		10,000	-	-	-	2,500
H1 - High Energy Pipe Hanger Inspection & Mtc	555(512)		9,700	-	-	-	2,425
H - Rebuild 2B Conveyor Telescopic Chute	555(512)		-	46,014	-	-	11,503
H - Rebuild 3A Reclaim Feeder	555(512)		-	20,110	-	-	5,028
H - Barge Mooring Cell Inspection & Repair	555(512)		-	40,221	-	-	10,055
H - "B" Elliot Air Compressor 5-Year Inspection	555(512)		-	18,786	-	-	4,697
H - Barge Unloader OEM Inspection	555(512)		-	14,400	-	-	3,600
H - Barge Unloader OEM Repairs	555(512)		-	34,510	-	-	8,628
H - Rebuild #1 Conveyor Load Zone	555(512)		-	26,400	-	-	6,600
H - Rebuild #1 Conveyor Outlet Coal Chute	555(512)		-	25,903	-	-	6,476
H - Rebuild 4A & 4B Conveyor Outlet Chutes	555(512)		-	-	25,241	-	6,310
H - Recondition Genie Manlift	555(514)		-	-	9,021	-	2,255
H - "A" Elliot Air Compressor 5-Year Inspection	555(512)		-	-	18,372	-	4,593
H - Mooring Cell Repairs	555(512)		-	-	-	94,014	23,503

Big Rivers Electric Corporation
Case No. 2011-00036
Non-Outage Operations and Maintenance Expenses

Description: During the historical test period, Big Rivers incurred $33,216,868 in non-outage O&M expenses. The non-outage O&M expenses during this period was lower than the planned spending over the next four years. The pro forma adjustment of $5,660,678 serves to normalize the expenses associated with non-outage O&M.

120		Reid/Station Two						
121	**Non-Outage Task Description**	**Account**	**Test Year**	**2011**	**2012**	**2013**	**2014**	**Adjustment**
122	R - Rebuild 2B Conveyor Telescopic Chute	512		-	9,586	-	-	2,397
123	R - Rebuild 3A Reclaim Feeder	512		-	4,190	-	-	1,047
124	R - Barge Mooring Cell Inspection & Repair	512		-	8,379	-	-	2,095
125	R - "B" Elliot Air Compressor 5-Year Inspection	512		-	3,914	-	-	978
126	R - Barge Unloader OEM Inspection	512		-	3,000	-	-	750
127	R - Barge Unloader OEM Repairs	512		-	7,190	-	-	1,797
128	R - Rebuild #1 Conveyor Load Zone	512		-	5,500	-	-	1,375
129	R - Rebuild #1 Conveyor Outlet Coal Chute	512		-	5,397	-	-	1,349
130	R - Rebuild 4A & 4B Conveyor Outlet Chutes	512		-	-	5,259	-	1,315
131	R - Recondition Genie Man lift	514		-	-	1,879	-	470
132	R - "A" Elliot Air Compressor 5-Year Inspection	512		-	-	3,828	-	957
133	R - Mooring Cell Repairs	512		-	-	-	19,586	4,897
134	R1 - Boiler Feed Pump OH (A & B)	512		120,000	-	-	-	30,000
135	R1 - Inspect Boiler Vent and Drains	512		23,000	-	-	-	5,750
136	R1 - Condenser Wash	513		11,000	-	-	-	2,750
137	R1 - Combustion Air Flow Study	512		31,000	-	-	-	7,750
138	R1 - Crusher Overhaul	514		28,000	-	-	-	7,000
139	R1 - Inspect Main Steam Piping	512		55,000	-	-	-	13,750
140	R1 - Stack Inspection	512		25,000	-	-	-	6,250
141	R1 - "A" & "B" Condensate Pump Overhaul	513		31,000	-	-	31,000	15,500
142	R1 - Feedwater Heater Isolation Valve Reseat	512		23,000	-	-	23,000	11,500
143	R1 - FD & PA Fans Inlet Vanes Rebuild	512		30,000	-	-	30,000	15,000
144	R1 - Precipitator Hopper Inspection/Repair	512		-	-	-	27,000	6,750
145	R1 - A & B Rating Dampers Inspection/Repair	512		-	-	-	28,000	7,000
146	R1 - A & B Mill Classifier Rebuild	512		-	-	-	34,000	8,500
147	H2 - "B" Circ Water Pump (Cooling Tower)	555(512)		-	88,400	(157,300)	(157,300)	(56,550)
148	H - Mooring Cell Repairs	555(511)		-	-	-	94,014	23,503
149	R - Mooring Cell Repairs	511		-	-	-	19,586	4,897
150	H2 - OH "B" Auxiliary Circulating Water Pump	555(512)		10,000	-	-	-	2,500
151	H2 - Rebuild C/T "B" Makeup Pump	555(512)		21,000	-	-	-	5,250
152	H - Concrete Support Column (2B Conveyor)	555(511)		-	73,241	-	-	18,310
153	R - Concrete Support Column (2B Conveyor)	511		-	15,259	-	-	3,815
154	Misc	555(514)		(2,848)	45,617	(399,162)	(37,432)	(98,456)
155	Total Adjustments			1,543,010	1,791,162	263,484	1,118,915	1,179,143
156								
157	**Total Reid/Station II Non-Outage Adjusted**			7,321,991	7,570,144	6,042,466	6,897,897	6,958,125
158								
159	**Total Big Rivers Non-Outage Adjusted**							**38,879,559**

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

DIRECT TESTIMONY

OF

DAVID G. CROCKETT
VICE PRESIDENT, SYSTEM OPERATIONS

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
DAVID G. CROCKETT

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DIRECT TESTIMONY
OF
DAVID G. CROCKETT

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is David G. Crockett. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson Kentucky, 42420, as its Vice President, System Operations. I have held this position since January 2006. Prior to 2006 I held several positions in the Engineering Department and in 1998 assumed responsibility for the Energy Control Department as Manager over both areas. Altogether I have been employed by Big Rivers for a total of 38 years. I am a registered Professional Engineer in Kentucky. I graduated in 1972 from the University of Kentucky with a Bachelor of Science degree in Electrical Engineering.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before this Commission in transmission system-related cases. Most recently I testified in Case No. 2010-00043, *In the Matter of Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc.*

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (i) describe Big Rivers' experience to date with its status as a transmission-owning member of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") which commenced on December 1, 2010; (ii) provide the latest information on potential Midwest ISO cost projections; and (iii) describe the status of the Phase 2 Transmission Projects.

III. <u>MIDWEST ISO EXPERIENCE</u>

Q. Is Big Rivers now a transmission-owning member of the Midwest ISO?

A. Yes. Pursuant to the Commission's Order in 2010-00043, *In the Matter of Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc.*, and pursuant to the Orders of the Federal Energy Regulatory Commission ("FERC") in Docket Nos. ER10-1024-000, ER11-15-000 and ER11-16-000, Big Rivers became a transmission-owning member of the Midwest ISO effective December 1, 2010.

Q. Have the conditions that caused Big Rivers to seek approval for transferring functional control of its transmission system to the Midwest ISO changed since the Commission approved Big Rivers' request to join the Midwest ISO?

A. No. The conditions described by Big Rivers in Case No. 2010-00043 are essentially unchanged. Joining the Midwest ISO was the least-cost means available to enable Big Rivers to satisfy its Contingency Reserve obligations and avoid potential penalties for non-compliance from the North American Electric Reliability Corporation ("NERC") and the SERC Reliability Corporation ("SERC"). Big Rivers is now satisfying those obligations by virtue of its membership in the Midwest ISO and its access to the Midwest ISO Open Access Transmission, Energy and Operating Reserves Tariff ("Midwest ISO Tariff") under which Contingency Reserve service is provided.

Q. Did the integration of Big Rivers into the Midwest ISO significantly affect the business activities of Big Rivers?

A. Yes. When the integration into the Midwest ISO took place, Big Rivers began to take service under the FERC-approved Midwest ISO Tariff. Several functional areas of Big Rivers were affected by the integration into the Midwest ISO by virtue of the Midwest ISO Tariff. These include the transmission operations, transmission planning, energy services and production areas.

Q. How did the integration into the Midwest ISO affect the transmission operations area?

A. When the integration into the Midwest ISO took place, the Midwest ISO took over certain responsibilities that were handled by Big Rivers prior to the integration. The Midwest ISO assumed responsibility for the functional control of the Big Rivers transmission system. This includes the activities associated with providing basic transmission service to wholesale transmission customers, including tariff administration, Open Access Same-Time Information System ("OASIS") management, and the provision of ancillary services (e.g. scheduling and dispatch, load following, reactive power support, energy imbalance, and reserves). In this sense the Midwest ISO took over some of the duties that were performed by Big Rivers' transmission operations staff before the integration.

Q. How did the integration into the Midwest ISO affect the transmission planning area?

A. Before the integration into the Midwest ISO, transmission planning functions were focused primarily on the Big Rivers system and its interconnections with adjacent transmission systems. Since the integration into the Midwest ISO, transmission planning functions have shifted to focus on collaborating with the Midwest ISO staff for coordination of the Big Rivers transmission plans with those of the entire transmission system under the Midwest ISO's functional control. Big Rivers now provides data to the Midwest ISO staff and participates in the Midwest ISO

Transmission Expansion Planning ("MTEP") process. The MTEP process is a transmission planning process established by the Midwest ISO and its Board of Directors. The aim of the process is to improve and guide transmission investment in the region, reflecting a fully integrated view of project value inclusive of reliability, market efficiency, public policy, and other value drivers across all planning horizons. By participating in the MTEP process, Big Rivers' transmission planners now collaborate with the Midwest ISO system planning staff on developing transmission expansion plans for the entire Midwest ISO region, along with plans for necessary expansions of the Big Rivers system.

Q. How did the integration into the Midwest ISO affect the Energy Services area?

A. The integration into the Midwest ISO caused the activities of the Energy Services group to change. Among other activities, the Energy Services group manages load forecasting, billing, and off-system sales. The integration into the Midwest ISO has introduced new functions, including but not limited to, (i) providing bids and offers into the Midwest ISO real-time, day-ahead and ancillary services markets, (ii) providing resource adequacy information to the Midwest ISO, (iii) closely managing bills for backup services for the Domtar Cogeneration facility and associated energy imbalances, (iv) correctly capturing the Midwest ISO-related billing determinants associated with surplus sales or backup energy for the Smelters, and (v) providing short and long term load forecasts to the Midwest ISO, and other, more routine tasks.

Q. How did the integration into the Midwest ISO affect the dispatch of generators in the Big Rivers system?

A. The integration into the Midwest ISO caused the generation dispatch activities to change also. The generating units are now included in the Midwest ISO regional resource dispatch as part of the Midwest ISO Energy and Operating Reserves Market pursuant to the Midwest ISO Tariff. Big Rivers relies on ACES Power Marketing

("APM") for services related to the Midwest ISO market participation, as further described in the Direct Testimony of Mr. John Wolfram.

Q. Given all of the changes noted, how would you characterize the overall experience of Big Rivers as a Midwest ISO member to date?

A. Because the integration took place so recently, at this time it is premature to make a meaningful assessment of our Midwest ISO experience to date. As indicated above, there are significant internal process and functional adjustments underway to accommodate the integration into the Midwest ISO. This was anticipated and is progressing as our understanding of the day-to-day requirements of the Midwest ISO membership increases. Big Rivers will further refine those adjustments as its experience operating as a Midwest ISO member grows.

IV. <u>MIDWEST ISO COST PROJECTIONS</u>

Q What cost does Big Rivers now incur as a result of its membership in the Midwest ISO?

A. Big Rivers incurs several costs now that the integration into the Midwest ISO has taken place. These include but are not limited to charges under the following schedules billed by the Midwest ISO:

- Schedule 10 — ISO Cost Recovery Adder
- Schedule 10 FERC — FERC Annual Assessment Recovery
- Schedule 16 — FTR Administrative Service Cost Recovery Adder
- Schedule 17 — Energy Market Support Cost Recovery Adder
- Schedule 23 — Recovery of Schedule 10 and Schedule 17 Costs from Certain Grandfathered Agreements
- Schedule 24 — Local Balancing Authority Cost Recovery

- Schedule 26 — Network Upgrade Charge from Transmission Expansion Plan

There are also charges associated with Revenue Sufficiency Guarantees ("RSG") and Revenue Neutrality Uplifts ("RNU"). Prospectively, there may be additional charges applicable to Big Rivers pursuant to the Midwest ISO Tariff that have not been incurred to date.

Q. Has the Midwest ISO projected costs for Big Rivers in 2011 and beyond?

A. Yes. The Midwest ISO has projected costs for Big Rivers for 2011 through 2014. These costs for 2011 are incorporated into a pro forma adjustment to test year expenses and are discussed in more detail in the testimony of Mr. John Wolfram.

Q. Do the projected costs include costs associated with Schedule 26?

A. No. However, Big Rivers will be subject to Schedule 26 charges for its share of qualified transmission projects identified in the MTEP process.

Q. What costs does Schedule 26 include?

A. Schedule 26 includes the properly allocated costs associated with reliability upgrades (those network upgrades that are necessary to meet NERC reliability criteria during the planning horizon) and economic upgrades (those network upgrades that are beneficial to one or more market participants, but are not necessary to meet NERC reliability criteria during the planning horizon) for projects that are approved and included in the MTEP. Schedule 26 may also include the costs of any Multi-Value Projects ("MVPs") pursuant to the Midwest ISO MVP Filing in FERC Docket No. EL10-1791-000, which was approved by the FERC on December 16, 2010. MVPs are projects that enable the reliable and economic delivery of energy in support of documented energy policy mandates and address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones. As costs are incurred for any of these projects, Big Rivers may be allocated a share of the costs via Schedule 26.

Q. Are projects of the sort you described included in the most recently-approved MTEP?

A. Yes. In August 2010, the Midwest ISO Board of Directors approved the 2010 Midwest ISO Transmission Expansion Plan ("MTEP10"). The MTEP10 addressed the planning horizon for 2011 through 2020. The plan included (i) the recommendation of 230 new projects totaling $680 million; (ii) one MVP project totaling $510 million targeted at integrating renewable energy; (iii) identification of a 2011 candidate MVP portfolio; and (iv) various other findings on scenarios, cost allocation methodologies, assessments and investigations. The full plan is available on the Midwest ISO website at www.midwestiso.org/Library/Repository/Study/MTEP/MTEP10/MTEP10_final_report_12072010.pdf

III. PHASE 2 TRANSMISSION PROJECTS

Q. Did the Commission grant Big Rivers a Certificate of Public Convenience and Necessity for the construction of a transmission line that, together with other transmission system additions and improvements, are known now as the Phase 2 Transmission Projects, in Case No. 2007-00177?

A. Yes. Furthermore, in Appendix A Item 22 of Case No. 2007-00455 (the "Unwind Proceeding"), Big Rivers committed to complete the construction of the Phase 2 Transmission Projects and to advise the Commission and the Attorney General's Office on a timely basis of the date those transmission facilities become fully operational and of any material events related to the Big Rivers transmission system that impact Big Rivers' long-term ability to wheel excess power to its border for sale into other markets.

Q. Please list the Phase 2 Transmission Projects.

A. The Phase 2 Transmission Projects are listed in Table 1.

Table 1. Phase 2 Transmission Project List

#	Name
1	Reid to Daviess Co. 161kV Line Upgrade
2	Coleman EHV to Coleman 161kV Line #1 & #2 Upgrades
3	Coleman to Newtonville 161kV Line Upgrade
4	Wilson to New Hardinsburg/Paradise tap 161kV Line
5	Wilson 161kV Line Terminal
6	Tap to Paradise 161kV Line Upgrade

Q. Is Big Rivers continuing work on the projects?

A. Yes; some projects are complete and others are in progress.

Q. Please describe the status of each project.

A. The status of each project is described in Table 2 below.

Table 2. Phase 2 Transmission Project Status

#	Name	Start Date	Target End Date	Status
1	Reid to Daviess Co. 161kV Line Upgrade	10/2007	1/2009	Complete
2	Coleman EHV to Coleman 161kV Line #1 & #2 Upgrades	12/2009	8/2010	Complete
3	Coleman to Newtonville 161kV Line Upgrade	11/2008	1/2010	Complete
4	Wilson to New Hardinsburg/Paradise 161kV Line	9/2008	12/2011	In Progress
5	Wilson 161kV Line Terminal	11/2009	6/2011	In Progress
6	Tap to Paradise 161kV Line Upgrade	5/2010	1/2011	Complete

Q. Does Big Rivers anticipate that all of the projects will be complete in 2011?

A. Yes. On projects of this scale, it is expected that the duration of certain tasks in the schedule will vary, but at this time we expect all of the Big Rivers system projects to be completed during 2011. At this time, it is anticipated that the completion of certain TVA system interconnection facility upgrades at Paradise associated with these Big Rivers system improvements will extend beyond 2011. However, should one or both of the Smelters close, Big Rivers will be able to operate the system on a temporary basis to achieve the desired power export capability until the TVA system improvements can be completed.

IX. <u>CONCLUSION</u>

Q. Do you have any closing comments?

A. Yes. From a transmission standpoint, Big Rivers is meeting its obligations to provide safe and reliable transmission service to its customers. Big Rivers is satisfying its NERC reliability criteria and is adapting its business practices to conform to the on-going requirements of its membership in the Midwest ISO. Big Rivers is also satisfying its commitments to the Commission regarding the Phase 2 Transmission Projects. These activities come at a cost. Base rate increases are simply necessary at this time in order for Big Rivers to adequately recover its costs, including the costs I refer to in my testimony. The rates proposed herein should be approved by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

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

DIRECT TESTIMONY

OF

TED J. KELLY
PRINCIPAL, BURNS & McDONNELL

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
TED J. KELLY

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DIRECT TESTIMONY

OF
TED J. KELLY

I. INTRODUCTION

Q. Please state your name and business address.

A. Ted J. Kelly; 9400 Ward Parkway; Kansas City, Missouri 64114.

Q. What is your occupation?

A. I am a Principal at the firm of Burns & McDonnell. I currently serve as a Senior Project Manager and Principal in the company's Business and Technology Services Division.

Q. How long have you been associated with the firm Burns & McDonnell?

A. I have been with the firm continuously since July 1998. Prior to that, I was employed with another major consulting firm from January 1978 to July 1998. During the period August 1981 to May 1983, I was a full time student at Indiana University.

Q. What is your educational background?

A I am a graduate of the University of Missouri at Rolla, with a Bachelor of Science Degree in Economics and a minor in Engineering Management. I am also a graduate of Indiana University with a Masters Degree in Business Administration in Utility Regulation and Management.

Q. What is your professional experience?

A. I have been responsible for numerous engagements involving electric, gas and other utility services. Clients served include cooperative utilities, publicly owned utilities, investor owned utilities, customers of such utilities, municipalities and regulatory agencies. During the course of these engagements, I have been responsible for the preparation and presentation of studies involving valuation, depreciation, cost of service, allocation, rate design, pricing, financial feasibility, cost of capital, and other financial, economic and management issues.

Q. What is the nature of the business of Burns & McDonnell?

A. Burns & McDonnell is a full-service engineering, architecture, construction, environmental and consulting solutions firm. Our multi-disciplined staff of more than 3,000 employee-owners includes engineers, architects, construction experts, planners, estimators, accountants, economists, technicians and scientists representing virtually all design disciplines. Burns & McDonnell has provided comprehensive construction, engineering, consulting and management services to utility, industrial and governmental clients since 1898. The firm specializes in engineering, consulting and construction associated with utility services including electric, gas, water, wastewater, waste disposal, and telecommunications. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, cost studies, rate and financial reports, valuation and depreciation studies, reports on operations and general consulting services. We plan, design, permit, construct and manage facilities throughout the United States and numerous foreign countries.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of Big Rivers Electric Corporation ("Big Rivers").

Q. Have you ever testified before this Commission or any other state or federal regulatory agency?

A. I have not previously testified before the Kentucky Public Service Commission, but I have testified before the Texas Public Utility Commission and the Kansas Corporation Commission. In addition, I assisted in the preparation of testimony submitted to the Wyoming Public Service Commission, the New York Public Service Commission, and the Connecticut Department of Public Utility Control.

II. PURPOSE OF TESTIMONY

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

A. I sponsor the Burns & McDonnell Report on the Comprehensive Depreciation Rate Study ("the 2010 Depreciation Study") prepared for Big Rivers. The Study was performed for all of Big Rivers' facilities accounted for in accordance with Rural Utilities Service ("RUS") Bulletin 1767B-1. The 2010 Depreciation Study is based on historical plant records of Big Rivers as of April 30, 2010. It was initiated and completed to meet the Commission's mandate in Appendix A Item 12 of its Order of March 6, 2009, in Case No. 2007-00455, that Big Rivers conduct a new depreciation rate study as part of its submission in connection with its intent to file for a general review of its operations and tariffs.

III. 2010 DEPRECIATION STUDY

Q. Did you prepare the Comprehensive Depreciation Rate Study ("the 2010 Depreciation Study")?

A. The 2010 Depreciation Study was prepared under my supervision and direction.

Q. What is your professional experience in the field of depreciation?

A. I have prepared and supervised the preparation of numerous depreciation rate studies and useful life analyses for cooperative utilities and publically owned utilities.

Q. When was the last depreciation rate study completed for Big Rivers?

A. The last depreciation rate study was completed for Big Rivers by Burns & McDonnell in 1998.

Q. What is depreciation?

A. The FERC Uniform System of Accounts defines depreciation as:

> The loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes considered are wear and tear, decay, action of the elements, inadequacy, changes in the art, and changes in demand and requirements of public authorities.

A. Scope and Purpose

Q. What was the scope and purpose of the current Study?

A. The current Study was conducted to analyze the service life characteristics, net salvage indications, and depreciation reserve status based on historical data from Big Rivers' Continuing Property Records ("CPR") system data, and then to derive appropriate depreciation rates for Big Rivers' system plant in service.

B. Findings and Conclusions

Q. What are your findings and conclusions?

A. Based on the results of the Burns & McDonnell analysis, we find that Big Rivers should pursue approval and implementation of the proposed depreciation rates for each RUS account as presented in the Study. These depreciation rates will result in an increase in annual depreciation expense of approximately $4 million (11 percent) as shown in Table 1 in Exhibit Kelly-1.

C. Study Approach

Q. What was Burns & McDonnell's overall approach to meeting the requirements of the 2010 Depreciation Study?

A. First, Burns & McDonnell performed the following tasks:

1. Obtained information on the operating history, outages, operating expenses and generation statistics for all of the generation assets;

2. Obtained the property account records for all of Big Rivers' generation, transmission and general plant assets detailing original property cost, accumulated depreciation, additions and retirements;
3. Gathered data and information related to current staffing, maintenance procedures, scheduled maintenance, capital expenditures, and capital projects for generation, transmission and general plant assets;
4. Reviewed the data and information provided; and
5. Compared the performance statistics of Big Rivers' generation units to industry standards.

Q. What was the next major step in your approach?

A. Next, Burns & McDonnell completed physical site inspections of the generation and transmission assets. I personally participated in the site inspections and staff interviews. The tasks involved in this process included the following:

1. Observation of generating and transmission plant equipment and facilities;
2. Evaluation of the physical condition of equipment and facilities;
3. Interviews of generation operating and maintenance staff and transmission staff;
4. Review of organization structure, procedures, and staffing levels;
5. Assessment of facility operating and maintenance practices;
6. Collection of pertinent cost and operating data and records;
7. Collection of environmental data; and
8. Development of facilities descriptions.

After completing the inspections and interviews, Burns & McDonnell engineers applied their experience and engineering judgment in developing an Engineering Assessment (Part II of the 2010 Depreciation Study) for each facility and approximating the remaining useful lives of each asset.

Q. How did you develop the depreciation rates?

A. The projected remaining lives of the various transmission assets and generating assets for each plant from the Engineering Assessment were then factored into the depreciation rate analysis performed by Burns & McDonnell's depreciation consultants. The 2010 Depreciation Study included analysis of the service life characteristics; projected net salvage values; removal costs; and depreciation reserves for the generating assets, as well as for the transmission and general plant assets. The resulting depreciation rates are shown in Table 1 of Exhibit Kelly-1.

Q. In preparing the 2010 Depreciation Study, did you follow generally accepted accounting practices in the field of depreciation?

A. Yes.

D. ***Report Contents***

Q. What are the contents of the 2010 Depreciation Study report?

A. Part I, Introduction, discusses Big Rivers, the purpose of the 2010 Depreciation Study, the project approach and sources of data. Part II, Engineering Assessment, provides a summary review of the engineering assessment of the Big Rivers plant assets in service as of April 30, 2010. Part III, Depreciation Rate Analysis, describes the methodology and the analysis performed in the formulation of proposed new depreciation rates for the electric generation, transmission, and general assets of Big Rivers. Part IV provides the Summary & Conclusions.

Q. Please describe the Engineering Assessment.

A. The Engineering Assessment provides a summary review of the engineering analysis and site inspections performed by Burns & McDonnell for the Big Rivers plant assets in service as of April 30, 2010. During the 2010 Depreciation Study, the following activities were conducted to examine Big Rivers' plant in service from an engineering perspective:

1. A discussion of each production facility's basic design and equipment;
2. An on-site review and analysis of each production facility's current operating condition;
3. An analysis of each production facility's historical performance;
4. A discussion of the operating and maintenance procedures and staffing for each production facility;
5. An analysis of external and environmental factors that may impact each facility's useful life;
6. An opinion, based on the study's findings, regarding the remaining economic life of each facility and the proper depreciation rate schedule to be used prospectively; and
7. A discussion of the composition of the transmission system.

Q. How is this used to determine depreciation rates?

A. The remaining life of each facility is provided in the Engineering Assessment and is a key component that is used in the calculation of depreciation rates.

E. ***Facilities Review***

Q. What facilities were reviewed?

A. A description of each of the facilities physically inspected and reviewed by Burns & McDonnell is provided in Table 2 in Exhibit Kelly-2.

i. <u>Robert D. Green Plant</u>

Q. Describe the Robert D. Green facility.

A. The Robert D. Green Plant ("Green Plant") is located on the Sebree site near Sebree, Kentucky, along with the Robert A. Reid Plant ("Reid Plant") and Henderson

Municipal Power & Light Station Two ("HMP&L Station Two"). Green Plant Unit 1 is rated for net continuous capacity of 231 MW and Green Plant Unit 2 has a rated net capacity of 223 MW. Unit 1 began commercial operation in 1979 and Unit 2 became operational in 1981. Both units at the Green Plant are coal-fired steam generating units with Babcock & Wilcox boilers providing maximum steam capacity of 1,930,000 pounds per hour. Green Plant Unit 1 is equipped with a General Electric turbine-generator with a nameplate rating of 242,105 kW. Green Plant Unit 2 includes a Westinghouse turbine-generator rated at 242,133 kW.

Q. How has the Green Plant been operated?

A. Burns & McDonnell reviewed the Green Plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the necessary level of reliability to meet Big Rivers' electric production requirements. Both Green Plant units have been performing well. Combined they have had a five year net heat rate of 11,202 Btu per kWh, which is competitive with other coal fired power plants in the region. The availability of the units has also been good. Green Plant Unit 1 had an Equivalent Forced Outage Rate ("EFOR") of 1.9 percent in 2009 and 1.4 percent in 2010. Green Plant Unit 2 had an EFOR of 0.81 percent in 2009 and 0.44 percent in 2010.

Q. What is the estimated remaining useful life for the Green Plant?

A. Green Plant Unit 1 and Unit 2 are both in excellent condition for their age and service requirements. Provided that operations and maintenance are prudent in the future, these units are estimated to be suitable for ongoing service through the year 2042. Of particular note is the Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the High Energy Piping ("HEP") and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is consistent with prudent utility practice. The HEP and hanger review addresses the concern over creep damage with an aging plant.

ii. Henderson Municipal Power & Light Station Two

Q. Describe the Henderson Municipal Power & Light Station Two facility.

A. HMP&L Station Two is also located on the plant site near Sebree, Kentucky, along with the Reid Plant and the Green Plant. HMP&L Station Two is owned by the City of Henderson, Kentucky ("City") through its municipal utility, Henderson Municipal Power & Light. Big Rivers has a life-of-the-unit lease on both of the HMP&L units and splits costs with the City. HMP&L Station Two Unit 1 is rated for net continuous capacity of 153 MW and HMP&L Station Two Unit 2 has a rated net capacity of 159 MW. Unit 1 began commercial operations in 1973 and Unit 2 began commercial operations 1974. Both HMP&L Station Two units are coal-fired steam generating units with Riley boilers having steam flow capacity of 1,180,000 pounds per hour. Unit 1 is equipped with a General Electric turbine-generator with nameplate rating for the turbine of 175,984 kW. Unit 2 includes a Westinghouse turbine-generator rated at 178,724 kW.

Q. How has HMP&L Station Two been operated?

A. Burns & McDonnell reviewed the HMP&L Station Two's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the necessary level of reliability to meet Big Rivers' electric production requirements. Both HMP&L Station Two units have been performing well. Combined, the units have had a five year net heat rate of 10,993 Btu per kWh, which is competitive with other coal fired power plants in the region. The availability of the units has also been reasonable, with the exception of a turbine blade failure on Unit 1 in 2009 which resulted in 1,247 forced outage hours, yielding an EFOR of 17.2 percent for the year. Unit 1 EFOR was back down to 3.4 percent in 2010. Unit 2 had an EFOR of 2.1 percent in 2009 and 6.7 percent in 2010.

Q. What is the estimated remaining useful life for the HMP&L Station Two facility?

A. The HMP&L Station Two units are in excellent condition for their age and service requirements. Provided that operations and maintenance are prudent in the future, these units are estimated to be suitable for ongoing service through the year 2035. Of particular note is the Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the High Energy Piping and hangers.

iii. Robert A. Reid Plant

Q. Describe the Robert A. Reid Plant.

A. The Reid Plant is also located on the plant site near Sebree, Kentucky. The Reid Plant steam turbine generating unit is currently 44 years old. The equipment in this unit includes a Riley boiler with a steam flow capacity of 690,000 pounds per hour and a General Electric turbine-generator with nameplate capacities of 66,000 kilowatts (kW) for the turbine and 96,000 kVA for the generator. The unit is currently rated at 65 MW.

Q. How has the Robert A. Reid Plant been operated?

A. Burns & McDonnell reviewed the Reid Plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the necessary level of reliability to meet Big Rivers' electric production requirements. The Reid Plant has performed commendably over the years given the level of investment in plant maintenance. However, the unit had one of the highest heat rates on Big Rivers' system. The five-year average heat rate for the unit was reported to be 13,805 Btu per kWh. This is relatively high for coal fired power plants in that region of the country, which is why the unit is dispatched primarily as a peaking unit only. In addition, the average EFOR of 25.0 percent is considerably high when compared to other coal fired power plants in the region.

Q. What is the estimated remaining useful life for the Robert A. Reid Plant?

A. The Reid Plant has not been run as many hours per year as other facilities and is in excellent condition for its age given the level of investment in plant maintenance. If operations and maintenance are prudent in the future and the Reid Plant is run at the same level as it has been run, this unit is estimated to be suitable for ongoing service through the year 2036. A Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the HEP and hangers is also kept for this facility.

iv. D. B. Wilson Plant

Q. Describe the D.B. Wilson Plant.

A. The D. B. Wilson Plant ("Wilson Plant") is located at Island, Kentucky, approximately 55 miles from Henderson, Kentucky. The Wilson Plant consists of a single 417 MW unit commercialized in 1986. It is the newest and largest generating unit on the Big Rivers electric system. The Wilson Plant site is configured for installation of one or more additional units and therefore, the Wilson Plant facilities (such as coal handling, water supply, ash handling, and sludge disposal) all have more than adequate capacity for the operating requirements.

Q. How has the D.B. Wilson Plant been operated?

A. Burns & McDonnell reviewed the Wilson Plant's historical operating performance and can verify that the generating unit has a competitive heat rate and is capable of providing the necessary level of reliability to meet Big Rivers' electric production requirements.

Q. What is the estimated remaining useful life for the D.B. Wilson Plant?

A. The details provided for the D.B. Wilson Plant are the most comprehensive of any of the Big Rivers facilities. The Wilson Plant is in excellent condition for its age and service requirements. Provided that operations and maintenance are prudent in the future, this unit is estimated to be suitable for ongoing service through the year 2051. The Wilson Plant also keeps a Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the HEP and hangers.

v. Kenneth C. Coleman Plant

Q. Describe the Kenneth C. Coleman Plant.

A. The Kenneth C. Coleman Plant (Coleman Plant) consists of three coal-fired, steam turbine generating units located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. The Coleman Plant is located on the west bank of the Ohio River. The adjacent land is occupied by Century Aluminum and is the site of an aluminum reduction facility, a primary customer of power from the plant.

The Coleman Plant is located on the flood plain of the Ohio River and operation could be affected by extreme flood levels. In the past, the Coleman Plant has experienced temporary isolation due to flooding of local access roads. However, the main plant area is located at a sufficient elevation to ensure that 100-year floods should not affect the plant's generation capabilities. Although a flood in excess of 100-year levels potentially could cause temporary interruptions of generating capability, this would not be anticipated to result in major disaster.

Unit 1 was commercialized in 1969 and is rated for 150 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160,000 kW. Unit 2 was commercialized in 1970 and is rated for 138 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing

1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160,000 kW. Unit 3 was commercialized in 1972 and is rated for 155 MW of net capacity. The unit is equipped with a Riley boiler capable of producing 1,160,000 pounds per hour of steam, and a General Electric turbine-generator with nameplate capacity of 160,000 kW.

Q. How has the Kenneth C. Coleman Plant been operated?

A. Burns & McDonnell reviewed the Coleman Plant's historical operating performance and verified that the generating units have competitive heat rates and are capable of providing the necessary level of reliability to meet Big Rivers' electric production requirements.

Q. What is the estimated remaining useful life for the Coleman Plant?

A. Units 1, 2, and 3 are in good condition for their age and type. Provided that the inspections and maintenance activities are prudent in the future, then the units can be expected to give satisfactory service for at least another 25 years. This facility maintains a Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the HEP and hangers.

vi. <u>Robert A. Reid Combustion Turbine</u>

Q. Describe the Robert A. Reid combustion turbine.

A. The Robert A. Reid combustion turbine is a General Electric Frame 7 combustion turbine was placed in operation in 1976, with a net output rating of 65 MW. It is capable of firing #2 fuel oil or natural gas. Considered part of the Reid station, this unit is also located at the Sebree, Kentucky site with the HMP&L Station 2 and the Robert D. Green plant.

Q. How has the Robert A. Reid combustion turbine been operated?

A. The Robert A. Reid combustion turbine is still maintained, but is only run periodically if the price of power is high or it is needed to maintain system reliability.

Q. What is the estimated remaining useful life for the Robert A. Reid combustion turbine?

A. The relatively low number of operating hours for the Robert A. Reid combustion turbine indicates that, with prudent maintenance it should provide reasonably available capacity for a number of years into the future. There are currently enough of these units being operated in a similar manner throughout the country to ensure that replacement and maintenance parts will continue to be available.

vii. <u>Transmission Assets</u>

Q. Was an engineering assessment conducted on the transmission assets?

A. Yes. The following efforts were conducted to examine Big Rivers' transmission system plant in service from an engineering perspective:

- Review of Big Rivers' retirement records and history;
- Analysis of current operating and maintenance programs as well as each facility's current operating conditions;
- Analysis of the external or environmental factors that may impact the depreciation rates; and
- Estimation of the remaining service life of major transmission facilities.

Q. What is the estimated remaining useful life for the transmission system and substations?

A. In addition to physical observations, the estimated remaining useful lives for Big Rivers' transmission assets was based primarily on national industry standards regarding the expected useful life of major electric substation equipment.

The Reid Plant EHV substation is approximately 28 years old. Assuming a prudent level of maintenance on the substation, the Reid substation as a whole can expect to be still functioning properly for an additional 30 years.

The Coleman Plant EHV substation is approximately 28 years old. Assuming a prudent level of maintenance on the substation, the Coleman substation as a whole can expect to be still functioning properly for an additional 30 years.

The Wilson Plant EHV substation is approximately 28 years old. Assuming a prudent level of maintenance on the substation, the Wilson substation as a whole can expect to be still functioning properly for an additional 30 years.

The Hancock Substation is approximately 40 years old. Typically, substation transformers and circuit breakers are replaced within the electric industry any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Brown insulators are considered obsolete by industry standards, and may need to be considered as part of future maintenance work. However, assuming a prudent level of maintenance on the substation, the Hancock substation appears to be in good working order and could continue to function properly for an additional 20 years.

The Hardinsburg Substation is 42 years old. Typically, substation transformers and circuit breakers are replaced within the electric industry any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Several of the insulators are considered obsolete by industry standards, and may need to be considered as part of future maintenance work. However, assuming a prudent level of maintenance on the substation, the Hardinsburg substation appears to be in good working order and could continue to function properly for an additional 20 years.

Q. How were the remaining useful lives of these assets incorporated into the depreciation analysis?

A. The current best estimates of future retirement dates for each generating station as described above were used as inputs to the Life Span model along with the actuarial analysis and engineers' judgment for each plant account. At facilities where multiple units are forecasted to retire in different years, the retirement date of the last surviving unit was used as the date of retirement for the entire production facility. This is reasonable for two reasons. First, the units are expected to retire within two years of each other. Most importantly, it is realistic to assume that the entire facility would shut down before significant demolition activities begin to occur. Piecemeal removal at an operating facility would be costly and much of the plant infrastructure would need to remain in service in order to maintain the last unit's ability to function.

Account 312 contains some much newer environmental compliance assets such as scrubber equipment that have a shorter expected life than the other assets in Account 312. These assets were broken out into Account 312 A-K. In addition, assets such as mist eliminator panels and slag grinders with even shorter useful lives were subdivided into Account 312 V-Z and to Account 312 L-P (if they were related to environmental compliance). Despite having a shorter useful life than other assets in Account 312, the remaining life of these environmental assets is still constrained by the remaining life of the plant as a whole because the environmental assets would be retired when the overall plant is retired.

Also, the Wilson Plant is significantly newer than the other facilities. As such, its remaining plant balance is significantly larger in comparison to the other facilities. A simple average of the remaining service life of each facility is 28 years. An average of the remaining service lives of each facility weighted by capacity (MW) is also 28 years. If the remaining service life of each facility is weighted by the remaining plant balances in Account 311 –Structures, Account 312 –Boiler Plant, and Account 314 – Turbine the weighted average remaining service life increases to 30 years. As such, the remaining service life for Account 311 –Structures was assumed to be 30 years and the remaining service life for Account 312 –Boiler Plant and Account 314 –Turbine was assumed to be 28 years.

F. ***Depreciation Analysis and Methods***

Q. Describe the depreciation analysis.

A. The depreciation rate analysis was performed based on the electric generation and transmission historical plant records of Big Rivers as of April 30, 2010. The methodologies and basis for completing this Study is similar to the process utilized in completing the 1998 Depreciation Rate Study. This depreciation rate analysis was conducted to analyze the service life characteristics, net salvage values, and depreciation reserve status based on historical data from Big Rivers' CPR system data, and then to derive appropriate depreciation rates for Big Rivers' system plant in service.

Q. Describe the depreciation rate study methods you employed.

A. Two primary methods were used to calculate depreciation rates: the Whole Life method and the Life Span method combined with the Remaining Life technique. The Whole Life method was used for most General Plant accounts and the Life Span method combined with the Remaining Life technique was used for all Transmission accounts and all Production accounts and Account 390 – Structures.

Q. Describe the Whole Life depreciation method.

A. For each account where used, the Whole Life method uses the account average service life (ASL) and the average net salvage percentage (NS) for the account to calculate the annual depreciation rate according to the following formula:

$$(1 - NS)/ASL$$

Whole life depreciation rates are appropriate for mass property types of accounts where there are a large number of relatively small property units with no definite or planned final retirement, retirements of individual units are independent of each other, and additions are generally independent of existing units. Examples of typical property falling in this category include tools, vehicles, computers, and furniture.

Estimates of average service life and dispersion were studied using the retirement rate method of actuarial analysis based upon the historical nature of the characteristics of the plant retired from each account since inception. For accounts for which insufficient activity had occurred on which to conduct actuarial analysis, or the results of such an analysis were inconclusive, other publicly available industry information and the engineering judgment of the depreciation consultant were relied upon to estimate reasonable average service lives and/or average net salvage values.

Q. Describe the Life Span depreciation method.

A. The Life Span method calculates lives for an asset group or account based on the assumption that all property units in the group will retire concurrently at a single forecasted point in time, whether the units are part of the initial installation or later additions. Examples of typical property falling in this category include poles, transformers, conductors, power production facilities and buildings. Forecasting reasonable retirement dates is the most critical aspect of the Life Span method.

During the life of an operational power plant and building, portions of the facility are retired and replaced. Examples of these items typically include roofs, HVAC equipment, boiler tubes and walls, pumps, and piping allocated to the cost of the facility. Because not all items remain the entire length of time a power plant or building remains in service, these so-called interim retirements tend to decrease the life of the dollars in the group or account. Therefore, it is important in a depreciation study to analyze the historical interim retirement amounts and whether the interim retirement rates are expected to continue at the same pace over the remaining life of the unit. Interim retirements can be studied mathematically using the system of Iowa curves, the Gompertz-Makeham formula, or derived interim retirement rate curves. The property data was readily available and interim retirement life tables were developed separately for each of the accounts under the Life Span method.

Although detailed retirement records are maintained for each building and production facility, retirements for most locations are relatively few and little applicable information could be derived from attempting an analysis on such a sparse data set. Therefore, to improve the strength and validity of the retirement rate analysis, retirement rate calculations were performed for each account as a whole, rather than by account and then by location.

Technical engineering experts assessed the Big Rivers electric plant facilities regarding their design, performance, operation and maintenance, and condition, and provided estimates of final retirement dates for each production plant and each general plant structure to the depreciation consultants as inputs to the depreciation model. The Engineering Assessment of the major system facilities is contained in Part II of the Study. For each production account and buildings account, an average year of final retirement (AYFR) was calculated for each major facility using the direct weighted average of individual retirement years and plant balances to retire. This AYFR and the aforementioned interim retirement rates are inputs to the Remaining Life calculation for each account.

The Remaining Life depreciation rate automatically adjusts for past under- and over-accruals by building those amounts into the depreciation rate calculation using the reserve ratio (RR). The RR is the depreciation reserve amount divided by the plant balance at the point in time of the study, (April 30, 2010 for this study). The net salvage parameter in the Remaining Life rate equation is the future net salvage rate (FS). The Remaining Life depreciation rate is expressed mathematically as:

$$\frac{1 - FS - RR}{\text{Remaining Life}}$$

Actuarial methods are the most accurate and applicable in the determination of historic trends for assessing average service lives and salvage specific to a plant account when there is significant annual turnover of plant in that account. However, the limited activity in several accounts prevented reliable actuarial analyses. For accounts for which insufficient retirement activity had occurred on which to conduct actuarial analysis, or for which the results of such an analysis were inconclusive, other publicly available industry information, the Engineering Assessment in Section II and the engineering judgment of the depreciation consultants were relied upon to estimate reasonable average service lives.

Q. How did you perform the net salvage analysis?

A. The net salvage value for each transmission and general plant account was calculated as an average of the available historical data by system account provided by Big Rivers. The net salvage figures used in the depreciation rate formula for production and the building account are for final net salvage, i.e., the gross proceeds realized less any removal cost to raze the structures represented in the account, if any.

Burns & McDonnell's engineers and depreciation consultants performed analyses of available data and information in order to assess whether specific detailed estimates of terminal removal costs for each of the Big Rivers generating stations could be developed with reasonable substantiation. In particular, due to the significant potential costs that would be required for any environmental remediation required at the Big Rivers plant sites, the net salvage values were developed exclusive of any rough engineering estimates of future terminal removal costs of major plant facilities. Instead the historical removal costs provided by Big Rivers were considered in the projected net salvage values.

In addition, Big Rivers sold personal property to Western Kentucky Energy Corporation ("WKEC") at the inception of a lease in July, 1998. This transaction was recorded as salvage value. Therefore, the salvage values associated with the transaction have been subtracted from the overall balance of salvage value for the purpose of determining depreciation rates.

The net salvage rates for Accounts 352 to 356 were calculated from the available historical data from 1965 to 2010 in the Big Rivers CPR system. However, the retirement and salvage data for Account 354 -Towers is extremely limited. This results in an unrealistically high Net Salvage Factor of 56%. After removing the outlying values, the Net Salvage Factor for Account 354 -Towers is 0%.

Q. How did you calculate removal costs?

A. Removal costs were calculated based on actual data from Big Rivers' CPR System. However, from mid 1998 until July of 2009 (lease period) removal costs associated with plant additions were capitalized by WKEC and then reported as capital additions to Big Rivers. Big Rivers had no control over this accounting methodology. Going forward, Big Rivers will record removal costs according to RUS guidelines as they did previously from 1965 to mid 1998.

Removal costs have a direct and significant effect on depreciation rates. With the knowledge that in the future Big Rivers will record removal costs as they did previously from 1965 to 1998, removal costs from 1998 to 2010 need to be included in the analysis to determine more accurate depreciation rates to apply going forward. Since there is no actual data available for the Production Plant removal costs from 1998 to 2010, removal costs for this period were estimated based on the 33 years of actual removal costs incurred from 1965 to mid 1998 for each Production Plant account.

G. Study Results

Q. What are the results of your study?

A. Proposed depreciation rates were developed for all of Big Rivers' in service generation, transmission, and general plant assets based on historical plant accounting records provided by Big Rivers' CPR system, other published depreciation survey information, and generally-accepted depreciation analysis methodologies. Based on the analysis of the information provided by Big Rivers and the results of the on-site observations of the Big Rivers' generation and transmission facilities, Burns & McDonnell prepared estimates of the remaining useful service lives for the facilities.

Table 1 in Exhibit Kelly-1 presents the proposed remaining life estimates and the corresponding proposed depreciation rates for each plant account balance of Big Rivers' in service production, transmission and general plant as of April 30, 2010. This table also provides comparison calculation of Big Rivers' annual depreciation expense, calculated using the existing and proposed depreciation rates. This comparison shows that if the proposed depreciation rates are approved, the result will be an increase in depreciation expense of approximately $4 million per year based on April 30, 2010 account balances.

H. Recommendation

Q. What is your recommendation?

A. I recommend the Kentucky Public Service Commission approve the proposed depreciation rates set forth in Table 1 of Exhibit Kelly-1 for prospective application by Big Rivers.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Big Rivers Electric Corporation
Case No. 2011-00036

Table 1: 2010 Depreciation Rate Study Summary

Account	Description	As of April 30, 2010 Plant Balance	Reserve Balance	Reserve Ratio	Existing Depreciation Rate	Average Service Life	Remaining Service Life	Net Salvage Factor	Proposed Depreciation Rate	Annual Depreciation Expense Existing	Proposed	Variance
		- $ -	- $ -		- % -	- Years -	- Years -	- % -	- % -	- $ -	- $ -	- $ -
310	Land & Land Improvements	4,537,577	0	0.0	N/A	N/A	N/A	N/A	N/A	-	-	-
PRODUCTION PLANT [1]												
340	Land	475,968	-	-	-	-	-	-	-	-	-	-
311	Structures	124,375,974	78,124,758	62.8	1.71%	62	30	-4.5%	1.38%	2,126,829	1,717,828	(409,001)
312	Boiler Plant	667,206,536	347,026,279	52.0	1.79%	60	28	-5.0%	1.88%	11,942,997	12,543,396	600,399
312 A-K	Boiler Plant - Env Compl	574,184,346	216,760,670	37.8	1.89%	53	28	-2.0%	2.28%	10,852,084	13,074,185	2,222,101
312 L-P	Short-Life Production Plant -Environmental	3,208,938	165,475	5.2	1.89%	10	5	0.0%	20.22%	60,649	648,949	588,300
312 V-Z	Short-Life Production Plant -Other	868,755	210,738	24.3	1.89%	10	5	0.0%	14.39%	16,419	125,054	108,634
314	Turbine	225,272,354	124,744,924	55.4	1.66%	60	28	-8.2%	1.91%	3,739,521	4,309,293	569,772
315	Electric Eqpt	60,355,721	35,350,377	58.6	1.60%	51	19	3.0%	1.99%	965,692	1,202,952	237,260
316	Misc Eqpt	3,014,912	42,128	1.4	1.83%	58	26	0.5%	3.78%	55,173	113,919	58,746
341	CT - Structures	154,233	115,766	75.1	2.31%	53	21	0.0%	1.17%	3,563	1,804	(1,759)
342	CT - Fuel Holders & Access.	1,436,912	564,590	39.3	2.32%	53	21	-134.8%	9.10%	33,336	130,751	97,414
343	CT - Prime Movers	4,915,886	3,637,977	74.0	2.47%	53	21	-38.3%	3.02%	121,422	148,408	26,986
344	CT - Generators	1,102,964	984,479	89.3	2.23%	53	22	0.0%	0.50%	24,596	5,511	(19,085)
345	CT - Access. Elec. Eqpt.	317,726	179,425	56.5	2.23%	53	21	0.0%	2.05%	7,085	6,510	(575)
	Subtotal	1,666,891,222	807,907,587							29,949,367	34,028,559	4,079,192
TRANSMISSION [1]												
350	Land	558,665	-	-	-	-	-	-	-	-	-	-
352	Structures	6,725,346	3,664,345	54.5	1.76%	53	25	-2.4%	1.90%	118,366	127,998	9,632
353	Station Eqpt	115,297,358	51,467,633	44.6	2.22%	53	25	-0.2%	2.23%	2,559,601	2,573,726	14,125
354	Towers	8,593,544	4,868,075	56.6	2.28%	58	30	0.0%	1.42%	195,933	122,186	(73,747)
355	Poles	41,558,164	22,321,791	53.7	3.24%	50	23	0.0%	2.06%	1,346,485	854,950	(491,535)
356	Lines	41,070,042	23,399,406	57.0	2.47%	53	26	0.0%	1.69%	1,014,430	692,966	(321,464)
	Subtotal	213,803,120	105,721,250							5,234,815	4,371,826	(862,989)

Big Rivers Electric Corporation
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Table 1: 2010 Depreciation Rate Study Summary

Account	Description	As of April 30, 2010 Plant Balance	Reserve Balance	Reserve Ratio	Existing Depreciation Rate	Average Service Life	Remaining Service Life	Net Salvage Factor	Proposed Depreciation Rate	Annual Depreciation Expense Existing	Proposed	Variance
		- $ -	- $ -		- % -	- Years -	- Years -	- % -	- % -	- $ -	- $ -	- $ -
GENERAL PLANT [2]												
389	Land	407,251	-	-	-	-	-	-	-	-	-	-
390	Structures [1]	3,944,895	1,786,210	45.3	2.59%	43	12	21.8%	2.84%	102,173	111,928	9,755
391.0/391.6/391.7	Office Furniture & Eqpt	616,135	(282,102)	-45.8	1.11%	10	8	8.9%	17.12%	6,839	105,460	98,621
391.2	Computer	7,013,902	436,114	6.2	1.11%	10	9	1.2%	10.29%	77,854	721,713	643,859
392.2	Vehicles - General	1,699,130	995,277	58.6	5.62%	10	6	14.2%	4.39%	95,491	74,575	(20,916)
392.3	Vehicles - Transmission	1,257,240	625,460	49.7	5.62%	10	5	16.9%	6.14%	70,657	77,173	6,517
393	Stores Eqpt	98,766	69,468	70.3	3.57%	16	6	4.4%	4.40%	3,526	4,349	823
394	Tools	717,086	385,947	53.8	2.85%	16	9	2.7%	4.61%	20,437	33,072	12,635
395	Lab Eqpt	221,279	160,195	72.4	2.86%	16	6	2.1%	4.41%	6,329	9,768	3,440
396	Power Operated Eqpt [3]	504,739	392,925	77.8	3.70%	16	5	24.9%	3.70%	18,675	18,675	-
397	Communication Eqpt [4]	1,639,437	1,640,029	100.0	4.35%	16	1	-0.1%	4.35%	71,316	71,316	-
398	Miscellaneous Eqpt	163,645	3,925	2.4	5.44%	16	8	3.2%	11.80%	8,902	19,309	10,407
	Subtotal	18,283,504	6,213,447							482,199	1,247,338	765,140
TOTAL		$1,903,515,423	$919,842,284							$35,666,381	$39,647,724	$3,981,343

[1] Life Span Method depreciation

[2] Whole Life Method depreciation

[3] This rate was set to 0% because the calculated rate was negative.

[4] Depreciation rate is equal to the previous rate due to Big Rivers current $7 million Replacement Program.

Big Rivers Electric Corporation
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Table 2 - Estimated Hours of Operation

Name	Net Capacity (MW)	Date in Service	Typical Lifetime Availability	Typical Operating Hours per Year	5 Year Average % On Line	Actual Operating Hrs Based on 5 Yr Avg	Years in Service	Total Est. Hours to Date (Jan 2009)	Typical Estimated Remaining Unit Life
COLEMAN 1	150	1969	80.0%	7,008	87.3%	7,648	40	280,320	25
COLEMAN 2	138	1970	80.0%	7,008	93.1%	8,154	39	273,312	25
COLEMAN 3	155	1972	80.0%	7,008	89.5%	7,843	37	259,296	25
GREEN 1	231	1979	85.0%	7,446	93.9%	8,225	30	223,380	32
GREEN 2	223	1981	85.0%	7,446	92.0%	8,056	28	208,488	32
HMP&L - 1	153	1973	85.0%	7,446	85.6%	7,497	36	268,056	25
HMP&L - 2	159	1974	85.0%	7,446	91.4%	8,005	35	260,610	25
REID 1	65	1966	70.0%	6,132	40.3%	3,529	43	263,676	26
WILSON 1	417	1986	89.5%	7,840	88.2%	7,724	23	180,325	41

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

DIRECT TESTIMONY

OF

MARK A. HITE
VICE PRESIDENT, ACCOUNTING

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
MARK. A. HITE

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DIRECT TESTIMONY
OF
MARK A. HITE

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Mark A. Hite. My business address is 201 Third Street, Henderson, Kentucky, 42420. I am employed by Big Rivers Electric Corporation ("Big Rivers" or "Company") as its Vice President of Accounting. I was first employed by Big Rivers in 1983, and have held various accounting and finance positions within the Company during my tenure. Prior to being employed by Big Rivers in 1983, I was employed as a Staff Accountant by Southern Indiana Gas & Electric Corporation ("SIGECO"), now Vectren Corporation, for three years.

Q. Have you previously testified before this Commission or other regulatory bodies?

A. Yes. I first testified before this Commission in 1997 in connection with Case Nos. 1997-00204 and 1998-00267 dealing with the 1998 Big Rivers/LG&E Energy Corporation Lease Transaction. Most recently, at the Commission's Public Hearing held on March 23, 2010, I testified to data responses which I sponsored in Case No. 2009-00510, a six-month review of Big Rivers' Fuel Adjustment Clause ("FAC").

Q. Briefly describe your education and professional certifications.

A. I obtained the degree of Bachelor of Science in Accounting in 1980, and the degree of Master of Business Administration in 1986, both from the University of Evansville. I became a Certified Public Accountant ("CPA") in 1990.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (a) present certain financial statements and records of Big Rivers, (b) explain the selection of the test year, (c) discuss the revenue requirements and Times Interest Earned Ratio ("TIER") impact, (d) discuss Big Rivers' credit rating and financings, (e) address certain commitments in Appendix A to the Commission's Order, dated March 6, 2009, in Case No. 2007-00455 (the "Unwind Transaction"), (f) review filing requirements of 807 KAR 5:001 that I am sponsoring, and (g) discuss a number of pro forma adjustments to Big Rivers' test year operating results.

III. FINANCIAL STATEMENTS AND RECORDS

Q. What financial reports has Big Rivers provided in connection with this Application?

A. Big Rivers' annual Financial and Statistical Report ("Annual Reports"), the most recent being for the 2009 calendar year, are on file with the Commission in accordance with 807 KAR 5:006, Section 3(1). Also, Big Rivers' monthly managerial reports providing financial results of operations, the Rural Utilities Service ("RUS") Form 12, for the 12 months in the year ending October 31, 2010, are provided in Exhibit 37 of this Application.

IV. TEST YEAR SELECTION

Q. Is Big Rivers filing a historical test period or forecasted test period in this Application?

A. Big Rivers is filing revenue requirements based on a historical test period corresponding to the 12 months ended October 31, 2010.

Q. Why was this test period selected?

A. The Unwind Transaction was approved by the Commission in its Order dated March 6, 2009, in Case No. 2007-00455 ("Unwind Order') and was effective at Midnight on July 16, 2009. The test year proposed in this proceeding includes a full year of operation, with a 3-1/2 month transition period, subsequent to the closing of the Unwind Transaction. In addition, as was discussed in the Unwind Proceeding, November 1, 2010, marked Big Rivers' transition from legacy business information technology systems to Oracle R12. Big Rivers thus deemed a 12-month historical test period ending October 31, 2010, to be appropriate because it included post-transition Unwind operations while avoiding reliance on a newly-implemented business information system platform.

V. REVENUE REQUIREMENTS AND TIER

Q. What is Big Rivers' Contract TIER?

A. TIER is the quotient, for a fiscal year, of (a) interest expense on long-term debt plus net margins, divided by (b) interest expense on long-term debt. Big Rivers has special contracts in place for two aluminum smelters, Rio Tinto Alcan ("Alcan") and Century Aluminum ("Century") (collectively, "Smelters"). These special contracts ("Smelter Agreements") define the TIER Adjustment in Section 4.7.5. The terms of this section effectively limit Big Rivers to a 1.24 TIER ("Contract TIER"), subject to defined Adjustments.

Q. What is Big Rivers' revenue deficiency?

A. Based on the revenue requirements designed to achieve a Contract TIER of 1.24, Big Rivers' revenue requirements deficiency is $39,952,927. The proposed base rates will increase total revenues by $39,953,956. The proposed net increase in total revenues is $29,603,235, when the total increase is reduced by the initial 2-year amortization of the Non-FAC PPA (estimated to be $3,236,077) and adjustment for placing the Smelters at the midpoint of the current Smelter "bandwidth" (calculated to be $7,114,653). These values are tabulated in the Direct Testimony of Mr. William Steven Seelye in Exhibit Seelye-6.

The 1.24 Contract TIER is consistent with the October 2008 Unwind Model filed with the Commission as Exhibit No. 79 in the Unwind Transaction.

Pursuant to the Smelter Agreements, any net margins in excess of the 1.24 Contract TIER are subject to being returned first to the Smelters via the TIER Adjustment Charge, and then to the Non-Smelters and Smelters alike via the Rebate Adjustment. Therefore, Big Rivers' margins are essentially capped at a 1.24 Contract TIER. But if Big Rivers' TIER falls too low, then Big Rivers will be at risk of failing to maintain two investment grade credit ratings from Moody's, S&P or Fitch and failing to meet its Margins for Interest Ratio ("MFIR") requirements, as set forth in its long-term debt agreements.

For each calendar year, Big Rivers' Indenture requires a minimum MFIR of 1.10. Note that per the revenue requirements in this case, "conventional TIER" (as opposed to Contract TIER) and MFIR for Big Rivers yield the same result. Based on the pro forma revenue requirements presented in this case, in accordance with Section 4.7.5(f) of the Smelter Agreements regarding the interest income on the Transition

Reserve, "conventional TIER" would be 1.25 versus a Contact TIER of 1.24. For each calendar year, Big Rivers' line of credit agreement with CoBank requires a minimum DSCR of 1.20 and that there be a minimum year-end equity-to-total-assets ratio of 15%. For each calendar year, Big Rivers' line of credit agreement with CFC requires that there be a minimum year-end equity-to-total-assets ratio of 12%.

With respect to its financial performance, Big Rivers has a narrow range in which to operate. Generally, Big Rivers cannot achieve a Contract TIER, as defined in the smelter service agreements, greater than 1.24 – which, it should be emphasized, is a fairly low ceiling – but Big Rivers must still earn sufficient margins to ensure that it meets the requirements set forth in its long-term debt agreements and its revolving credit agreements. It is important that Big Rivers establish base rates in this proceeding that will provide it with a reasonable opportunity to achieve a 1.24 Contract TIER.

Q. Is it possible for Big Rivers to over-earn?

A. No. It is important to recognize that Big Rivers is not an investor-owned utility. As a cooperative, Big Rivers is a not-for-profit entity. Because Big Rivers is a member-owned cooperative, there are no stockholders who potentially could be enriched by charging excessive rates. More significantly, though, as a practical matter, Big Rivers cannot earn margins that cause its Contract TIER to exceed 1.24. If its margins exceed the 1.24 Contract TIER, then Big Rivers would be subject to rebating any of the excess margins first to the Smelters under the TIER Adjustment provisions of the Smelter Agreements and then to the Non-Smelters and Smelters alike under the Rebate Adjustment.

Big Rivers is proposing a set of pro forma adjustments to the historical test period ended October 31, 2010, in this proceeding designed to be representative of operating results on a going-forward basis. Without including a number of these pro forma adjustments described by Mr. Wolfram in Exhibit Wolfram-1 to his Direct Testimony – notably the adjustments to reflect levelized production O&M expenses (Reference Schedules 2.10 and 2.11) and to reflect Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") expenses (Reference Schedule 2.14) – Big Rivers will either have to reduce expenses, including deferral of maintenance of its generating units, or risk violating covenants set forth in its long-term debt and revolving credit agreements.

We ask that the Commission recognize that if Big Rivers' rates generated more revenue than anticipated, thereby causing it to exceed a 1.24 Contract TIER, then rebates will be made to its Members. But, if Big Rivers' rates are set too low, then it will be required to reduce expenses, including deferral of scheduled maintenance on its generating units (which could have a harmful effect on reliability) or expose Big Rivers to the risk of not meeting the requirements set forth in its credit agreements. In other words, the risks of setting rates too low in this rate case proceeding are far greater to both Big Rivers and its Members than the risks of setting rates too high.

VI. CREDIT RATING AND FINANCINGS

Q. What are Big Rivers' current credit ratings?

A. Moody's rating on the $83.3 million Series 2010A pollution control bonds is Baa1, and S&P and Fitch have assigned a BBB- senior secured long-term debt issuer rating to Big Rivers. Big Rivers must maintain at least two investment grade ratings. As stated on page 38 of the Unwind Order, "the Commission well recognizes that an investment grade credit rating for Big Rivers is a linchpin of the financial model. Absent such a credit rating, neither Big Rivers' proposed financing plans nor the Unwind Transaction will be successful".

Q. From a financial perspective, are the post-Unwind results of operations generally consistent with those per the October 2008 Unwind Model?

A. Yes, generally, but there is one key difference. The off-system sales price has been, and is forecast to be, significantly below what was forecasted in the October 2008 Unwind Model. The October 2008 Unwind Model had an off-system sales price of $60.94/MWh in 2009, $59.20 in 2010, $63.59 in 2011 and $70.55 in 2012. The actual off-system sales price realized by Big Rivers in 2009 was $30.91. In 2010 Big Rivers realized only $37.90/MWh. Big Rivers sold 2.2 million MWh off-system in 2010. Big Rivers' 2011 budget includes 1.4 million MWh of off-system sales, assuming that the Smelters operate at full capacity, which they did not during 2010. This low market price has resulted in (i) the smelter rate being at the ceiling of the Smelter TIER Adjustment Charge "bandwidth," (ii) reduced net margins for Big Rivers, (iii) a lower cash balance, (iv) the implementation of cost-reduction and cost deferral measures, and (v) the deferral of generating unit planned maintenance activities.

Q. Since the July 16, 2009, Unwind closing, has Big Rivers has made the two required filings of the New Financial Model with this Commission?

A. Yes. The first such filing was made in October 2009, and the second was made in April 2010. The October 2009 filing included the budget for the post-Unwind 2009 period July 17 through December 31, the forecast for the years 2010 through 2013, and an explanation of significant assumptions. The April 2010 filing included actual financial results for 2009, the 2010 budget, the forecast for years 2011 through 2013, and an explanation of significant assumptions. Copies of these two filings are included as Exhibit Hite-1 and Exhibit Hite-2, respectively, to my testimony.

Q. Please briefly summarize and compare the key financial results of these two financial forecast filings to what you now know, including Big Rivers actual financial results for 2010.

A. In each case, the key difference is the off-system sales price. The October 2009 filing reflected an average off-system sales price of $53.20/MWh in 2010, $56.58 in 2011, and $57.59 in 2012. It reflected an 11.12% base tariff rate increase in 2012, which resulted in a Contract TIER of 1.24, with the Smelters at 53% (measured from the bottom to the top) of the TIER Adjustment Charge "bandwidth" in 2012.

The April 2010 filing contained an average off-system sales price of $46.82/MWh in 2010, $47.17 in 2011, and $47.51 in 2012. The April 2010 filing contained an 11.75% base tariff rate increase in 2012, which resulted in a Contract TIER of 1.24, with the Smelters at 94% of the TIER Adjustment Charge "bandwidth" in 2012.

Neither of these two financial forecasts made an attempt to estimate the outcome of a planned new depreciation study ("2010 Depreciation Study") that was mandated by this Commission in the Unwind Order. The 2010 Depreciation Study was recently completed and is discussed in the Direct Testimony of Mr. Ted J. Kelly. Big Rivers is proposing a pro forma adjustment to test year depreciation expenses (including but not limited to the effect of the depreciation rates in the 2010 Depreciation Study).

Additionally, upon acceptance of the depreciation rates by the Commission in this proceeding, Big Rivers will implement the new depreciation rates on the first day of a month. In other words, if the effective date of the new rates is the first day of a month, Big Rivers will implement the new depreciation rates on that date. If the effective date is not the first day of a month, Big Rivers will implement the new depreciation rates on the first day of the following month.

Even with significant cost containment efforts, both cost cuts and cost deferrals, Big Rivers needs a base tariff rate increase made effective by September 1, 2011, to meet its MFIR and generate cash working capital.

Q. How do the interest rates resulting from the June 8, 2010, Pollution Control Bond ("PCB") refunding compare to the interest rate assumed in the October 2008 Unwind Model?

A. Big Rivers has two issues of PCBs outstanding, the 3.25% (currently) variable rate $58.8 million 1983 Series having a bullet maturity of June 1, 2013, and the 6% fixed rate $83.3 million 2010A Series having a bullet maturity of July 15, 2031. The weighted average interest rate of these two issues is 4.86%. The October 2008 Unwind Model assumed a 5% interest rate for both issues of PCBs from their earlier planned 2013 and 2015 refinance dates through the balance of the forecast period.

Q. Does Big Rivers anticipate future debt refinancing or new borrowings?

A. Yes. Big Rivers will be required to pay down $60 million of principal on the 5.75% RUS Series A Note by October 1, 2012, and an another $200 million of principal by January 1, 2016. While not reflected in the revenue requirements in this proceeding, the requirement to pay down these principal amounts will likely be achieved by one or more refinancings. Also, the 3.25% variable rate $58.8 million 1983 Series PCBs will be refinanced by the current maturity date of June 1, 2013. Big Rivers' cash needs, as impacted by its revenue requirements, rates and capital expenditures, will influence the timing and amount of new borrowings. The anticipated refinancings/borrowings necessitate that Big Rivers maintain financial strength, i.e. good credit metrics, including meeting or exceeding the minimum required MFIR, DSCR and equity-to-assets ratios stated in Big Rivers' credit agreements, that enable Big Rivers to maintain its investment grade ratings.

VII. <u>UNWIND TRANSACTION COMMITMENTS</u>

Depreciation Study

Q. Has Big Rivers complied with the Commission's mandate that this Application include a new Depreciation Study?

A. Yes. Item 12 of Appendix A to the Unwind Order required Big Rivers to file within three years of closing the Unwind Transaction for a general review of its financial operations and its tariffs. Item 12 also required Big Rivers to include in the filing a new depreciation study. Accordingly, during 2010 Big Rivers solicited bids which led to its engaging Burns & McDonnell to perform a depreciation study. Burns & McDonnell, headquartered in Kansas City, Missouri, is a full-service engineering, architecture, construction, environmental and consulting solutions firm. As I noted earlier, a summary of the results of that depreciation study, including methodology and a depreciation schedule by major plant account, is included in the testimony of Mr. Ted Kelly, principal of Burns & McDonnell. Big Rivers is seeking the Commission's approval and the RUS's approval to implement the depreciation rates from the depreciation study on the first day of the month, either coincident with or following the effective date of the new tariff rates in this case as ordered by this Commission.

Q. Please briefly summarize and compare the depreciation expenses and the effective (composite) depreciation rate included in the October 2008 Unwind Model to the pro forma depreciation expenses and the effective depreciation rates included in this rate filing.

A. The October 2008 Unwind Model had an effective depreciation rate on gross plant in service of 1.77% in 2009 and 2010, 2.13% in 2011 through 2016, and 2.72% in 2017 through 2023. In the Unwind Model, the increase in depreciation expenses was essentially a two-step 50% phase-in, where the implicit service life for all property was reduced from approximately 56 years to 47 years, then to 37 years. Please see the table below.

October 2008 Unwind Model (Millions)			
	2009-2010	2011-2016	2017-2023
Average Gross Plant in Service	$ 1,974	$ 2,191	$ 2,493
Depreciation Expense	$ 35	$ 47	$ 68
Effective Depreciation Rate	1.77%	2.13%	2.72%

Similarly, as shown in the pro forma adjustment included in Wolfram Exhibit 2, Reference Schedule 2.06 – Depreciation Expenses, the implicit depreciation rates for all property as of October 31, 2010 from the current depreciation study and the new depreciation study are forth below.

Proforma Adjustment (Millions)		
	1998 Depreciation Study	2010 Depreciation Study
Average Gross Plant in Service	$ 1,989	$ 1,989
Depreciation Expense	$ 37	$ 43
Effective Depreciation Rate	1.86%	2.14%

The pro forma effective depreciation rate of 2.14% from the 2010 Depreciation Study is nearly identical to the 2.13% for years 2011 through 2016 per the October 2008 Unwind Model.

Accounting Commitments

Q. Has Big Rivers complied with each of the accounting commitments specified in Appendix A of the Commission's March 6, 2009, Order in the Unwind Transaction?

A. Yes. To the best of my knowledge, Big Rivers has complied with all the accounting commitments specified in Appendix A of the Unwind Order.

Non-FAC Purchased Power Adjustment

Q. Please discuss the accounting for the Non-FAC Purchased Power Adjustment.

A. The Non-FAC Purchased Power Adjustment ("NFPPA") Factor is calculated in accordance with Appendix A of the Agreements ("Smelter Agreements") with Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century") (collectively, "Smelters"). The purpose of NFPPA Factor is to recover purchased power costs expensed to Account 555, Purchased Power, attributed to Big Rivers' Members (Jackson Purchase Energy Corporation ("Jackson Purchase"), Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation ("Meade RECC") and not otherwise recovered in Big Rivers' FAC, excluding Big Rivers' Account 555 costs associated with Henderson Municipal Power and Light's Station Two ("HMP&L"), and backup power services for Domtar Paper Company, LLC, but including associated transmission and related costs expensed to Account 565. The NFPPA amount embedded in the base tariff energy rate is currently \$1.75/MWh.

The NFPPA is charged or credited to the Smelters' bills the second month following the month in which purchased power costs are incurred. For example, qualifying January (expense month) purchased power costs (those not eligible for the FAC) are used to calculate the NFPPA that is applied to January (service month) service and is reflected in the amount billed and collected in March (billing month). Big Rivers has recorded refunds of NFPPA amounts to the Smelters as a debit to Account 447.191 - Sales for Resale – Kenergy – Century and Alcan and a credit to Account 142.100 - Customer Accounts Receivable – Electric in the amount of

$8,150,843.40 through December 31, 2010. An additional liability in the amount of $1,985,963.21 for the NFPPA for Smelter sales has been recorded as a debit to Account 447.191 and a credit to Account to 242.990 - Accrued Liability-Other based on the proposed revisions to Appendix A of the Smelter Agreements discussed below.

In accordance the Commission's Order dated March 6, 2009, in the Unwind Transaction, Big Rivers established a regulatory account to defer the charges and credits that would have otherwise been billed to the non-Smelter Members (i.e., Jackson Purchase, Meade RECC, and Kenergy other than the Smelters) through the application of the NFPPA. Big Rivers has recorded as a debit to Account 557.350 - Other Expenses – Non-Smelter Non-FAC PPA and a credit to Account 254.350 - Other Regulatory Liability – Non-Smelter Non-FAC PPA a non-Smelter regulatory liability of $3,854,330.96 through December 31, 2010. As part of this general rate case, Big Rivers is requesting the Commission's approval to refund the deferred credit amount to the non-Smelter Members beginning September 1, 2011, using the Non-Smelter Non-FAC PPA mechanism as described in Mr. Seelye's Direct Testimony. An additional liability in the amount of $965,358.55 related to NFPPA for non-Smelter sales has been recorded based on the proposed revisions to Appendix A of the Smelter Agreements discussed below.

The Smelters complained to Big Rivers about the methodology Big Rivers used to calculate the NFPPA. Big Rivers and the Smelters have met on numerous occasions about their objection. At the time that Big Rivers was preparing this filing, the Smelters and Big Rivers had not reached complete agreement on a resolution, although Big Rivers believed that a resolution was imminent. As a result, this filing reflects that Big Rivers has recorded the NFPPA on its books in accordance with the resolution that

Big Rivers believes is appropriate and thought would be reached. Big Rivers and the Smelters continue to meet on this issue.

Economic Reserve, the Rural Economic Reserve and the Transition Reserve

Q. Please discuss the accounting employed by Big Rivers for each of the Economic Reserve, the Rural Economic Reserve and the Transition Reserve.

A. In accordance with the Commission's March 6, 2009, Order in the Unwind Transaction, upon the Unwind Transaction's closing, Big Rivers established deferred liabilities of the $157 million Economic Reserve (Account 254200) and the $60,855,790.94 Rural Economic Reserve (Account 254300). The $35 million Transition Reserve was recorded to Extraordinary Items, Account 434. Each of the three accounts was funded and invested, with the Rural Economic Reserve invested in U.S. Treasury Notes, Account 128300. The special deposit account for the Economic Reserve is Account 128200, and the special deposit account for the Transition Reserve is Account 128400. Interest earned on investment accounts for the Economic Reserve and Rural Economic Reserve is credited to the related balance sheet account. Interest income earned on the Transition Reserve is credited to Interest Income, Account 419040. The table below summarizes the status of the three reserve accounts at December 31, 2010:

Reserve Accounts as of December 31, 2010 (S)			
	Special Deposit	**Regulatory Liability**	**Interest Receivable**
Economic Reserve	124,627,684.74	122,928,610.42	339,729.92
Rural Economic Reserve	61,770,071.84	62,154,759.36	384,687.52
Transition Reserve	35,192,358.23	n/a	154,093.89
Totals	221,590,114.81	185,083,369.78	878,511.33

Please see Mr. Seelye's testimony for Big Rivers' proposal to transition the Member Rate Stability Mechanism ("MRSM") and Rural Economic Reserve once the MRSM expires.

SO_2 and NOx Emission Allowances

Q. Explain the accounting employed by Big Rivers for SO_2 and NOx emission allowances, and state whether Big Rivers purchased or sold any SO_2 or NOx allowances since the closing of the Unwind Transaction?

A. Big Rivers accounts for SO_2 and NOx allowances in accordance with RUS Bulletin 1767B-1, Uniform System of Accounts – Electric. Allowances are recorded at cost in Account 158.1, Allowance Inventory. Item 3 of Appendix A to the March 6, 2009, Order in Case No. 2007-00455, required Big Rivers not to sell SO_2 allowance in its inventory (excluding the 14,000 SO_2 allowance in conjunction with the Unwind Transaction) unless the sale is cost-effective based on a written policy which reflects short– and long-term allowance needs and prices. Because it has not sold any SO_2 or NOx allowances, Big Rivers is in full compliance with Item 3. Big Rivers does not acquire allowances for speculative purposes. The cost of the 14,000 "bank" of pre-2010 vintage SO_2 allowances acquired from Western Kentucky Energy Corporation ("WKEC") at the Unwind Transaction's closing was determined based on the $980,000 fair market value. The monthly issuance of allowances from inventory are accounted for on a vintage basis using a monthly weighted average cost methodology and charged to Account 509, Allowances. Any eligible allowances not used in the current vintage year are transferred to the vintage for the immediately following year. Cost of Allowances is a component of Big Rivers' monthly Environmental Surcharge.

VIII. FILING REQUIREMENTS FROM 807 KAR 5:001

Q. What filing requirements from 807 KAR 5:001 are you sponsoring?

A. I am sponsoring Big Rivers' responses to the filing requirements listed in

1. 807 KAR 5:001 Section 10(6)(a),
2. 807 KAR 5:001 Section 10(6)(i),
3. 807 KAR 5:001 Section 10(6)(j),
4. 807 KAR 5:001 Section 10(6)(t),
5. 807 KAR 5:001 Section 10(7)(a),
6. 807 KAR 5:001 Section 10(7)(b),
7. 807 KAR 5:001 Section 10(7)(c), and
8. 807 KAR 5:001 Section 10(7)(d).

807 KAR 5:001 Section 10(6)(a)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(6)(a).

A. As required by 807 KAR 5:001 Section 10(6)(a), I am sponsoring thirteen Pro Forma Adjustments which I briefly and individually summarize below. A complete description and quantified explanation for each Pro Forma Adjustment, with supporting documentation, is included in the associated exhibits.

807 KAR 5:001 Section 10(6)(i)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(6)(i).

A. While the revenue requirements in this case are not based on a return on rate base and capital, as required by 807 KAR 5:001 Section 10(6)(i), I provide a reconciliation of rate base and capital for the 12-month historical test period ended October 31, 2010, attached as Exhibit 28.

807 KAR 5:001 Section 10(6)(j)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(6)(j).

A. As required by 807 KAR 5:001 Section 10(6)(j), I provide a current chart of accounts, attached as Exhibit 29.

807 KAR 5:001 Section 10(6)(t)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(6)(t).

A. As required by 807 KAR 5:001 Section 10(6)(t), I note that, following termination of the leveraged lease of Big Rivers' Wilson and Green generating units in 2008, and the associated dissolution of Big Rivers Leasing Corp. in July 2009, Big Rivers now has no affiliates. As Big Rivers Leasing Corp. has been dissolved, no monies were paid to or on behalf of Big Rivers Leasing Corp. in the test year.

807 KAR 5:001 Section 10(7)(a)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(7)(a).

A. As required by 807 KAR 5:001 Section 10(7)(a), I provide a detailed statement of operations (income statement) and balance sheet reflecting the impact of all proposed Pro Forma Adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period ending October 31, 2010, attached as Exhibit 42.

807 KAR 5:001 Section 10(7)(b)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(7)(b).

A. As required by 807 KAR 5:001 Section 10(7)(b), I note that Big Rivers is not requesting any Pro Forma Adjustment for plant additions. Therefore, Big Rivers is not providing a capital construction budget, as this requirement is not applicable.

807 KAR 5:001 Section 10(7)(c)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(7)(c).

A. As required by 807 KAR 5:001 Section 10(7)(c), I note that Big Rivers is not requesting any Pro Forma Adjustment for plant additions. Therefore, Big Rivers is not providing the detailed information listed in 807 KAR 5:001 Section 10(7)(c), as this requirement is not applicable.

807 KAR 5:001 Section 10(7)(d)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(7)(d).

A. As required by 807 KAR 5:001 Section 10(7)(d), I provide Big Rivers' approved operating budgets for the years 2011 through 2014, a period encompassing all the Pro Forma Adjustments, as Exhibit 45.

IX. PRO FORMA ADJUSTMENTS TO YEST YEAR

Q. What Pro Forma Adjustment Schedules are you sponsoring?

A. I am sponsoring the following Pro Forma Adjustment Schedules noted in the Direct Testimony of Mr. Wolfram in Exhibit Wolfram-1

1. Schedule 2.06 – Depreciation Expenses,
2. Schedule 2.07 – Labor/Labor Overhead Expenses,
3. Schedule 2.08 – Interest Capitalized,
4. Schedule 2.09 – Reliant Resources Inc ("RRI") Domtar Cogenerator Back-Up Agreement,
5. Schedule 2.12 – Information Technology ("IT") Support Services Expenses,
6. Schedule 2.13 – Rate Case Expenses,
7. Schedule 2.15 – Interest Expense on Long-Term Debt,
8. Schedule 2.16 – Soaper Building Rent Expenses,
9. Schedule 2.19 – Western Kentucky Energy Corporation ("WKEC") Lease Income, Expenses, and Extraordinary Gain – Unwind "True-Up"
10. Schedule 2.20 – Southeastern Federal Power Customers ("SEFPC"),
11. Schedule 2.21 – Midwest ISO Case Expenses,

12. Schedule 2.23 – Promotional/Political/Institutional Advertising Expenses, Political/Lobbying Expenses, Donations, and Economic Development Expenses, and
13. Schedule 2.24 – Income Tax Expenses.

Schedule 2.06 – Depreciation Expenses

Q. Please briefly describe Schedule 2.06 – Depreciation Expenses.

A. As discussed above and in the testimony of Mr. Kelly, Schedule 2.06 – Depreciation Expenses sets forth annualized depreciation expenses at both the current rates per the existing depreciation study ("1998 Depreciation Study") and the new rates per the new depreciation study ("2010 Depreciation Study"). Each is then compared to the depreciation expense in the test year. Burns & McDonnell performed both the 1998 Depreciation Study and the 2010 Depreciation Study. These depreciation studies are included as attachments to Mr. Kelly's testimony.

Big Rivers requests the Commission to enter an Order approving the 2010 Depreciation Study and permitting Big Rivers to implement the new depreciation rates on the first day of the month, either coincident with or following the effective date of the new tariff rates in this case as ordered by this Commission. The 2010 Depreciation Study results in an increase in Big Rivers' revenue requirement of $6,252,652.

Schedule 2.07 – Labor/Labor Overhead Expenses

Q. Please briefly describe Schedule 2.07 – Labor/Labor Overhead Expenses.

A. Schedule 2.07 – Labor/Labor Overhead Expenses sets forth the annualized pro forma labor and labor overhead amount based on the 606 employees of record as of December 31, 2010. Of these 606 employees, 249 are non-bargaining unit employees, and 357 are bargaining unit employees. This 606 total excludes those on long-term disability ("LTD") for whom replacements have been hired. As planned, and consistent with the approved Unwind organization/staffing structure, Big Rivers continues transitioning to a full employee complement, filling all approved vacancies.

Base pay includes current pay rates, as well as qualification increases for non-bargaining employees, and step increases and contract increases for bargaining employees. Shift premiums are appropriately included. Overtime is based upon the amount currently expected for 2011, which is consistent with 2010. Labor overhead costs are based on the most current information, including premium rates and Statement of Financial Position (FAS) 87 and FAS 106 actuarial information.

Big Rivers notes that, as part of its recent cost-containment efforts, non-bargaining employees received no annual wage increase in 2010, and the 2011 non-bargaining wage increase was 2%. The pro forma amount does not include any incentive payout or bonus. The effect of this pro forma adjustment is to increase Big Rivers' revenue requirements by $624,894.

Schedule 2.08 – Interest Capitalized

Q. Please briefly describe Schedule 2.08 – Interest Capitalized.

A. Schedule 2.08 – Interest Capitalized shows an increase in revenue requirements. Big Rivers is seeking current recovery of interest capitalized on construction work in progress ("CWIP"). Accordingly, revenue requirements are being increased by the amount of interest capitalized in the test year, $515,767.

Schedule 2.09 – Reliant Resources Inc. Domtar Cogenerator Back-Up Agreement Interest Capitalized

Q. Please briefly describe Schedule 2.09 – Reliant Resources Inc ("RRI") Domtar Cogenerator Back-Up Agreement.

A. Schedule 2.09 – RRI Domtar Cogenerator Back-Up Agreement outlines an adjustment based upon Big Rivers' agreement with Domtar. By its terms, Big Rivers' agreement with RRI to provide back-up service for Domtar's cogenerator terminates March 31, 2011. While an agreement with RRI will not be renewed, Big Rivers has approved a new agreement whereby back-up service will essentially be provided for Domtar by the Midwest ISO with Domtar paying all associated cost. Accordingly, this pro forma adjustment serves to remove $2,086,416 for the RRI reservation fee and back-up power cost, as well as the associated $1,115,159 revenue Big Rivers receives from either Domtar or RRI. The net effect of this pro forma adjustment is to decrease Big Rivers' revenue requirements by $971,257.

Schedule 2.12 – Information Technology ("IT") Support Services Expenses

Q. Please briefly describe Schedule 2.12 – IT Support Services Expenses.

A. Schedule 2.12 – IT Support Services Expenses makes an adjustment for IT support services received from a subsidiary of LG&E and KU Energy LLC (*formerly* E.ON U.S. LLC) ("E.ON U.S."). As discussed in the Unwind Proceeding, during the test year, Big Rivers received these IT support services pursuant to an IT Support Services Agreement with E.ON U.S. that became effective upon the July 16, 2009, closing of the Unwind Transaction. Since that agreement was to terminate no later than January 15, 2011, Big Rivers contracted with Hewlett-Packard ("HP") to implement Oracle Release 12, R12/E-Business Suite. Following a 16-month implementation, Big Rivers went "live" with Oracle R12 on November 1, 2010. Big Rivers also outsourced various IT support functions to HP, including Oracle applications, help desk, desktop support, data center and infrastructure, pursuant to a seven-year service contract that terminates August 31, 2017.

Big Rivers' revenue requirements include the HP contract amount for the 12-month period ending August 31, 2012 ($2,189,242), based on the new tariff rates in this case being made effective September 1, 2011. The resulting net effect of this HP agreement versus the E.ON U.S. agreement is this pro forma adjustment to increase revenue requirements by $292,194.

Schedule 2.13 – Rate Case Expenses

Q. Please briefly describe Schedule 2.13 – Rate Case Expenses.

A. Schedule 2.13 – Rate Case Expenses itemizes expenses related to preparing this rate case filing. During the test year, Big Rivers incurred $17,924 to prepare this rate case filing. Big Rivers anticipates it will incur a total of $898,930 in legal and consulting costs including, but not limited to, the cost of service and rate design study and the depreciation study, to support this application and discovery related thereto. Big Rivers is including one-third of such amount, or $299,643 in its revenue requirements. The net effect of this pro forma adjustment is to increase Big Rivers' revenue requirements by $281,719.

Schedule 2.15 – Interest Expense on Long-Term Debt

Q. Please briefly describe Schedule 2.15 – Interest Expense on Long-Term Debt.

A. Schedule 2.15 – Interest Expense on Long-Term Debt annualizes, on a GAAP basis, interest expense on long-term debt, by applying the interest rates in effect at October 31, 2010, to outstanding debt on such date. Big Rivers' refinanced its $83.3 million 2001A Series Ohio County PCBs, now the 2010A Series, at a fixed rate of 6% on June 8, 2010. The 2010A Series is a bullet maturity on July 15, 2031. This pro forma adjustment increases Big Rivers' revenue requirements by $70,408.

Schedule 2.16 – Soaper Building Rent Expenses Schedule

Q. Please briefly describe Schedule 2.16 – Soaper Building Rent Expenses.

A. Schedule 2.16 – Soaper Building Rent Expenses addresses Soaper Building office space rental, as discussed in the Unwind Proceeding. The test year includes $128,368 Soaper Building office space rental expense for certain former WKEC employees. Post-Unwind, through May 2010, while Big Rivers' headquarters building was being remodeled to accommodate additional staff, Big Rivers leased office space previously leased by WKEC for certain former WKEC office staff. Big Rivers is removing this cost from its revenue requirements, resulting in a reduction in revenue requirements of $128,368.

Schedule 2.19 – WKEC Lease Income, Expenses, and Extraordinary Gain – Unwind "True-Up"

Q. Please briefly describe Schedule 2.19 – WKEC Lease Income, Expenses, and Extraordinary Gain – Unwind "True-Up".

A. Schedule 2.19 – WKEC Lease Income, Expenses, and Extraordinary Gain – Unwind "True-Up" addresses several post-Unwind closing accounting entries.. There were several such post-Unwind closing accounting entries for items including property taxes, materials and supplies inventories, CWIP, *etc*. There was also a significant post-retirement medical liability for the former WKEC employees assumed as of the Unwind closing date. This pro forma adjustment is to remove all such amounts included in the test year, resulting in a $4,969,814 decrease in revenue requirements.

Schedule 2.20 – Southeastern Federal Power Customers

Q. Please briefly describe Schedule 2.20 – Southeastern Federal Power Customers.

A. Schedule 2.20 – Southeastern Federal Power Customers reflects Big Rivers' recent termination of its long-time SEFPC membership as a cost-cutting measure. Accordingly, a pro forma adjustment is being made to remove the $180,775 cost from the test year and, thereby, reducing revenue requirements by that amount.

Schedule 2.21 – Midwest ISO Case Expenses

Q. Please briefly describe Schedule 2.21 – Midwest ISO Case Expenses.

A. Schedule 2.21 – Midwest ISO Case Expenses represents expenses incurred as part of Big Rivers' transferring functional control of its transmission system to the Midwest ISO. During the test year, Big Rivers incurred $1,305,377 in connection with Case No. 2010-00043. This Commission approved this transfer in its Order dated November 1, 2010. Following this Commission's approval, Big Rivers' successfully integrated into the Midwest ISO on December 1, 2010. This pro forma adjustment serves to amortize the entire $1,602,777 costs for such case over a 3 year period. Therefore, the net effect of this pro forma adjustment is to decrease Big Rivers' revenue requirements by $771,118.

Schedule 2.23 – Promotional/Political/Institutional Advertising Expenses, Political/Lobbying Expenses, Donations, and Economic Development Expenses

Q. Please briefly describe Schedule 2.23 – Promotional/Institutional Advertising Expenses, Lobbying Expenses, Donations, and Economic Development Expenses.

A. Schedule 2.23 – Promotional/Institutional Advertising Expenses, Lobbying Expenses, Donations, and Economic Development Expenses comports with 807 KAR 5:016 which requires excluding from revenue requirements those costs which are for promotional advertising or institutional advertising. One example of such costs is Touchstone Energy. This pro forma adjustment serves to also exclude civic, lobbying costs, donations (charitable contributions), penalties, and economic development costs. The effect of this pro forma adjustment is to reduce revenue requirements by $507,216.

Schedule 2.24 – Income Tax Expenses

Q. Please briefly describe Schedule 2.24 – Income Tax Expenses.

A. Regarding Schedule 2.24 – Income Tax Expenses, Big Rivers first failed the 85% member income test in 1983, and the Internal Revenue Service approved non-exempt filing status. Big Rivers generated net operating losses ("NOLs") for many years from 1983 through 1999 for both regular and alternative minimum tax ("AMT") purposes, and first became subject to the AMT for tax year 2000 due to consummation of a leveraged lease of its Wilson and Green facilities, due to the transaction being accounted for as a sale for income tax purposes. Except for the years 2001 and 2002, when the 90% AMT NOL limitation was suspended, Big Rivers has been subject to the AMT each year since 2000. As a result of the 2008 termination of the leveraged lease and the 2009 closing of the Unwind, both transactions having significant income tax ramifications for Big Rivers, it is unlikely that Big Rivers will pay either the regular tax or the AMT beyond 2011 (2011 results from a change in accounting method adopted by Big Rivers in 2008). Accordingly, but for a minor amount of on-going state income tax in connection with Big Rivers' ACES Power Marketing ("APM") membership, the test year amount is being eliminated from the revenue requirements. As the test year amount was actually a credit, the effect of this pro forma adjustment is to increase revenue requirements by $183,084.

X. CONCLUSION

Q. Please summarize your testimony.

A. Based on the revenue requirements designed to achieve a Contact TIER of 1.24, Big Rivers' revenue requirements deficiency is $39,952,927. We ask that the Commission consider that because of the TIER Adjustment provisions in the Smelter Agreements and the Rebate Adjustment of the tariff, there is essentially no risk that Big Rivers will earn an excessive level of margins by authorizing Big Rivers' proposed rate increase. An inadequate increase in revenues, on the other hand, could have serious consequences on Big Rivers, including the inability to meet its debt covenants, rendering Big Rivers insolvent, causing Big Rivers to lose its investment grade credit ratings, resulting in Big Rivers being unable to complete the previously mentioned required debt refinancings, and requiring Big Rivers to further delay scheduled maintenance of its generating units, which could potentially affect reliability.

Q. Does this conclude your testimony?

A. Yes.

Big Rivers
ELECTRIC CORPORATION

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270-827-2561
www.bigrivers.com

112.0.9

October 14, 2009

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

File: PSC

RE: Big Rivers Electric Corporation's New Financial Model

Dear Mr. DeRouen:

Enclosed are an original and five copies of the Big Rivers Electric Corporation ("Big Rivers") "New Financial Model." The enclosed model contains the Post-Closing 2009 Budget (July 17 - December 31) and the (current) Forecast for each of the years 2010 through 2012. The New Financial Model provides monthly data for July 2009 (last 15 days) through December 2011, 2012 is shown in total for the year. A hard copy of certain key elements of the enclosed Excel file (the sheet titled "Stmts RUS"), and an Excel file of the entire New Financial Model are enclosed. A listing of Significant Facts and Assumptions is also enclosed.

Actual financial results for the prior year are not included in the New Financial Model because the prior year is obviously not comparable in terms of Big Rivers' operations. If you believe that information would be helpful in this format, though, Big Rivers is willing to add it to the initial run of the New Financial Model.

Sincerely,

BIG RIVERS ELECTRIC CORPORATION

Mark A. Hite

Mark A. Hite, CPA
Vice President Accounting

Enclosures
c: Mr. Mark A. Bailey (with enclosures)
Mr. C. William Blackburn (with enclosures)
Mr. Albert Yockey (with enclosures)
Mr. Kelly Nuckols, Jackson Purchase Energy Corporation (with enclosures)
Mr. Sandy Novick, Kenergy Corp. (with enclosures)
Mr. Burns Mercer, Meade County RECC (with enclosures)
James Miller, Esq., General Counsel (with enclosures)

Significant Facts and Assumptions for Post-Close 2009 Budget and 2010 through 2012 Forecast

- No SO2 or NOX allowance sales.
- Member Sales - demand and energy billing units for Rural and Large Industrial load per the 2009 Load Forecast Study; Century @ 482 MW @ 98% load factor; Alcan @ 368 MW @ 98% load factor.
- PowerSimm Production Cost Model utilized for sources and uses of energy.
- Purchased Power: SEPA per agreement; market on economic dispatch basis per PowerSimm Production Cost Model, ensuring system load requirements are met. Purchased power is reflective of HMP&L Excess Energy Charge and the Non-Smelter Member Non-FAC Purchased Power Adjustment Regulatory Accounting.
- Assuming the current economic downturn continues, an 11.12% Member wholesale rate increase in 2012, with Smelters near median of TIER Adjustment Charge. Includes the Depreciation Methodology reflective of that included in the October 2008 Unwind Model.
- Regulatory Account for Non-Smelter Member Non-FAC Purchased Power Adjustment amortized over three-year period beginning 2012.
- Refunding of the $83.3 million Pollution Control Bond Issue in April 2010 to mature in August 2031. Interest rate of 6%, and refinancing costs of 1.74% amortized over life of bonds. Existing unamortized Ambac insurance premium expensed through April 2010 reflected in 2010 Forecast, but not 2009 Budget.

Significant Facts and Assumptions for Post-Close 2009 Budget and 2010 through 2012 Forecast

- The $58.8 million Pollution Control Bond Issue remains as Bank Bonds at 3.25%.
- $85 million borrowing October 2012, $60 million of which is used to pay down RUS Series A Note, ($25 million used to fund capital expenditures).
- Interest income rate 2010 thru 2012 - 0.30% General Fund; 0.92% Transition Reserve, 1.49% Economic Reserve; 1.87% Rural Economic Reserve.
- Post-Close 2009 Budget (July 17 – December 31) was approved by the Board in August 2009.
- Non-Variable Operation & Maintenance Non-Labor cost escalated at 2.5%; Bargaining Labor escalated at 3.2% per contract; Non-Bargaining reflects no increase in 2010 and 3% in 2011 and 2012; Labor Overheads escalated at 3% .
- Capital Expenditures: 2009 = $43.9 million; 2010 - $40.2 million; 2011 = $61.4 million; 2012 = $65.7 million.
- Year-end 2009 general fund cash balance = $66.9 million; 2010 = $59.1 million; 2011 = $30.3 million; 2012 = $35.1 million.

Significant Facts and Assumptions for Post-Close 2009 Budget and 2010 through 2012 Forecast

- Production Work Plan Revisions required to meet budget constraints:
  - ✓ 2010 – Coleman 2 and Green 1 outages moved to 2011. Reduced scope of Wilson outage. Cancelled certain generation-related projects.
  - ✓ 2011 – Coleman 1, Green 2 and Wilson 1 outages moved to 2012. Added Combustion Turbine inspection.
  - ✓ 2012 – Green 1 outage moved to 2013.
- Station Two: City of Henderson's take is 100 MW for fiscal year ending 5/31/2010, increasing 5MW annually thereafter. Letter dated April 30, 2009, from HMP&L states its intent to reserve 120 MW (of the 312 MW total) by June 1, 2013.

Big Rivers Electric Corporation

Calendar Year	2009 July	2009 August	2009 September	2009 October	2009 November	2009 December	2009 Total
I. Sales (TWH)							
Rural	0.11	0.24	0.20	0.17	0.18	0.22	1.12
Large Industrial	0.04	0.10	0.09	0.09	0.09	0.09	0.50
Century	0.17	0.35	0.34	0.35	0.34	0.35	1.90
Alcan	0.13	0.27	0.26	0.27	0.26	0.27	1.45
Market	0.06	0.14	0.13	0.01	0.11	0.18	0.64
Total Sales	0.52	1.09	1.03	0.90	0.98	1.10	5.62
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)							
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Rural							
Load Factor (%)	59.52%	60.69%	54.80%	60.84%	61.52%	64.88%	
Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	
Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	
Net Rate ($/ MWH)	37.36	37.04	38.82	37.00	36.81	35.96	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	9.73	9.84	8.60	6.83	8.36	8.68	
Environmental Surcharge	2.91	2.89	2.79	2.27	2.28	2.34	
Surcredit	(2.95)	(2.94)	(3.24)	(3.64)	(3.50)	(3.19)	
Total	9.69	9.79	8.15	5.46	7.13	7.82	
Economic Reserve	(9.69)	(9.79)	(8.15)	(5.46)	(7.13)	(7.82)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	37.36	37.04	38.82	37.00	36.81	35.96	
Large Industrial							
Load Factor (%)	79.93%	82.52%	79.72%	80.26%	76.29%	77.65%	
Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	
Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	
Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	
Net Rate ($/ MWH)	31.11	30.57	31.16	31.04	31.94	31.62	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	9.73	9.84	8.60	6.83	8.36	8.68	
Environmental Surcharge	2.91	2.89	2.79	2.27	2.28	2.34	
Surcredit	(2.95)	(2.94)	(3.24)	(3.64)	(3.50)	(3.19)	
PCA - Net	9.69	9.79	8.15	5.46	7.13	7.82	
Economic Reserve	(9.69)	(9.79)	(8.15)	(5.46)	(7.13)	(7.82)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	31.11	30.57	31.16	31.04	31.94	31.62	
Non-Smelter Member Blend							
Net Rate ($/ MWH)	35.63	35.17	36.41	34.94	35.24	34.72	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	9.73	9.84	8.60	6.83	8.36	8.68	
Environmental Surcharge	2.91	2.89	2.79	2.27	2.28	2.34	
Surcredit	(2.95)	(2.94)	(3.24)	(3.64)	(3.50)	(3.19)	
PCA - Net	9.69	9.79	8.15	5.46	7.13	7.82	
Economic Reserve	(9.69)	(9.79)	(8.15)	(5.46)	(7.13)	(7.82)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	35.63	35.17	36.41	34.94	35.24	34.72	

Big Rivers Electric Corporation

Calendar Year	2009 July	2009 August	2009 September	2009 October	2009 November	2009 December	2009 Total
Smelters							
Base Rate	28.15	28 15	28.15	28.15	28.15	28.15	
TIER Adjustment	1.95	1.95	1.95	1.95	1.95	1.95	
Smelter Rate Subject to Price Cap	30.10	30.10	30.10	30.10	30.10	30.10	
FAC, Non-FAC PPA, ES	11.69	11 72	11 06	12.24	11.32	10.12	
Surcharge 1	0.36	0.36	0.38	0.36	0.38	0.36	
Surcharge 2	1 20	1 20	1 20	1.20	1.20	1.20	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate	43.36	43.39	42.74	43.90	43.00	41.79	
Market	35.00	35.00	35.00	35.00	35.00	35.00	
III. Income Statement							
Electric Energy Revenues	22.41	46 50	43.34	38 39	41 22	45.11	236.96
Income From Leased Property Net	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Operating Revenue and Income	0.30	0.62	0.62	0.62	0.62	0.62	3.41
TOTAL OPER. REVENUES & PATRONAGE CAPITAL	22.71	47.12	43.96	39.01	41.84	45.73	240.36
Operating Expense-Production-Excluding Fuel	2.41	4.75	4.62	3.84	3.95	4.26	23.82
Operating Expense-Production-Fuel	9.18	20.33	17.86	13 66	16.63	19.17	97.13
Operating Expense-Other Power Supply	3.49	6.67	7.05	9.28	7.51	6 89	40.68
Operating Expense-Transmission	0.32	0.63	0.65	0.64	0.79	0.65	3.70
Operating Expense-Distribution							
Operating Expense-Customer Accounts							
Operating Expense-Customer Service and Information	0.04	0.07	0.07	0.07	0.07	0.07	0.38
Operating Expense-Sales	0.07	0.15	0.15	0.15	0.36	0.15	1.02
Operating Expense-Administrative and General	1.24	1.77	2.19	2.19	1.81	1.93	11.13
TOTAL OPERATION EXPENSE	17.05	34.37	32.59	29.83	31.12	32.92	177.87
Maintenance Expense-Production	1.40	2.77	3.24	12.22	2.99	2.35	24.96
Maintenance Expense-Transmission	0.22	0.39	0.61	0.42	0.39	0.41	2.44
Maintenance Expense-Distribution							
Maintenance Expense-General Plant	0.01	0.02	0.02	0.01	0.01	0.01	0.08
TOTAL MAINTENANCE EXPENSE	1.63	3.18	3.86	12.65	3.39	2.78	27.49
Depreciation and Amortization Expense	1.27	2 81	2 82	2 83	2.86	2.87	15.46
Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interest on Long-Term Debt	2.10	4.16	4.02	4.16	4.01	4.14	22.59
Interest Charged to Construction - Credit	(0.03)	(0.05)	(0.15)	(0.06)	(0.06)	(0.06)	(0.41)
Other Interest Expense							
Asset Retirement Obligation							
Other Deductions	0.00	0.01	0.01	0.01	0.01	0.01	0.04
TOTAL COST OF ELECTRIC SERVICE	22.02	44.48	43.14	49.42	41.32	42.65	243.04
OPERATING MARGINS	0.68	2.64	0.82	(10.41)	0.52	3.06	(2.67)
Interest Income	0.01	0.02	0.02	0.02	0.02	0.02	0.09
Allowance For Funds Used During Construction							
Income (Loss) From Equity Investments							
Other Non-Operating Income (Net)							
Generation and Transmission Capital Credits							
Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Extraordinary Items							
NET PATRONAGE CAPITAL OR MARGIN	0.69	2.65	0.83	(10.39)	0.54	3.09	(2.58)
IV. Balance Sheet							
Total Utility Plant in Service	1,936.87	1,940 58	1,947.50	1,970 13	1,981.33	1,984 63	
Construction Work in Progress	10.05	9 04	8.03	7.02	6.01	5.00	
Total Utility Plant	1,946.92	1,949.63	1,955.53	1,977.15	1,987.34	1,989.63	
Accum. Provision for Depreciation and Amort.	895.31	898.27	901.24	904.22	907.23	910.25	
NET UTILITY PLANT	1,051.61	1,051.36	1,054.29	1,072.94	1,080.12	1,079.38	

Big Rivers Electric Corporation

Calendar Year	2009 July	2009 August	2009 September	2009 October	2009 November	2009 December	2009 Total
Non-Utility Property (Net)							
Invest. in Assoc. Org - Patronage Capital	3.57	3.57	3.57	3.57	3.57	3.57	
Invest. in Assoc. - Other - General Funds	0.68	0.68	0.68	0.68	0.68	0.68	
Other Investments	0.02	0.02	0.02	0.02	0.02	0.02	
Special Funds	0.78	0.78	0.78	0.78	0.78	0.78	
Special Funds (Transition Reserve)	35.00	35.01	35.01	35.02	35.02	35.03	
Special Funds (Economic Reserve)	155.66	152.62	150.44	149.17	147.43	145.25	
Special Funds (Rural Economic Reserve)	60.86	60.87	60.88	60.89	60.89	60.90	
TOTAL OTHER PROPERTY AND INVESTMENTS	256.58	253.55	251.38	250.13	248.40	246.23	
Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	
Cash - Construction Funds - Trustee							
Special Deposits	0.57	0.57	0.57	0.57	0.57	0.57	
Temporary Investments	89.54	87.27	95.04	73.64	60.14	66.85	
Accounts Receivable - Sales of Eergy (Net)	22.41	46.50	43.34	38.39	41.22	45.11	
Accounts Receivable - Other (Net)	0.85	0.85	0.85	0.85	0.85	0.85	
Fuel Stock	36.20	33.35	30.92	29.23	27.10	24.52	
Materials and Supplies - Other	20.58	20.63	20.69	20.74	20.79	20.84	
Prepayments	5.18	4.93	4.68	4.42	4.17	6.91	
Other Current and Accrued Assets	2.24	2.24	2.24	2.24	2.24	2.24	
TOTAL CURRENT AND ACCRUED ASSETS	177.58	196.35	198.32	170.08	157.08	167.90	
Unamortized Debt Discount & Extraor. Prop. Losses	0.70	0.69	0.69	0.69	0.68	0.68	
Regulatory Assets	0.00	0.00	0.00	0.25	0.44	0.17	
Other Deferred Debits	1.43	1.43	1.43	1.43	1.43	1.43	
Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL ASSETS AND OTHER DEBITS	1,487.90	1,503.38	1,506.11	1,495.52	1,488.15	1,495.78	
TOTAL MARGINS & EQUITY	395.25	397.91	398.74	388.35	389.88	391.98	
Long-Term Debt - RUS	706.32	706.32	707.91	704.88	704.88	706.45	
Long-Term Debt - Other	142.10	142.10	142.10	142.10	142.10	142.10	
TOTAL LONG-TERM DEBT	848.42	848.42	850.01	846.98	846.98	848.55	
Notes Payable							
Accounts Payable	13.34	26.39	26.53	34.60	25.13	29.43	
Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	0.00	0.00	
Taxes Accrued	1.38	0.11	0.35	0.59	0.30	0.00	
Interest Accrued	1.88	5.58	7.55	3.89	7.46	8.56	
Other Current and Accrued Liabilities	3.51	3.52	3.53	3.54	3.54	3.55	
Other Current and Accrued Liabilities (Purchased Power)	0.15	0.48	0.58	0.00	0.00	0.00	
TOTAL CURRENT AND ACCRUED LIABILITIES	20.24	36.07	38.54	42.61	36.43	41.55	
Deferred Credits	0.00	0.00	0.00	0.00	0.00	0.00	
Deferred Credits (Economic Reserve)	155.66	152.62	150.44	149.17	147.43	145.25	
Deferred Credits (Rural Economic Reserve)	60.86	60.87	60.88	60.89	60.89	60.90	
Accumulated Operating Provisions	7.47	7.49	7.50	7.52	7.54	7.56	
Obligation under Capital Leases - Noncurrent							
TOTAL LIABILITIES AND OTHER CREDITS	1,487.90	1,503.38	1,506.11	1,495.52	1,488.15	1,495.78	
V. Cash Flow Statement							
Operating Receipts							
Rural	4.29	8.71	7.76	6.45	6.74	7.79	41.75
Large Industrial	1.37	2.91	2.86	2.86	2.78	2.76	15.52
Smelters	13.00	26.89	25.63	27.21	25.79	25.90	144.42
Offsystem	2.20	4.76	4.71	0.41	3.98	6.29	22.36
Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cobank Patronage Capital & Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interest Earnings	0.01	0.02	0.02	0.02	0.02	0.02	0.09
Total Receipts	20.88	43.28	40.98	36.95	39.31	42.75	224.14

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Calendar Year	2009 July	2009 August	2009 September	2009 October	2009 November	2009 December	2009 Total
Operating Disbursements							
PPA							
Fuel Costs	9.36	19.47	17.39	14.07	16.63	18.82	95.74
Fuel Costs (Labor & Exp)	0.37	0.70	0.66	0.71	0.56	0.64	3.65
Domtar	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Power Supply (Purch. Power, APM, Cogen, & TVA Tran)	1.41	2.87	3.55	6.53	4.23	2.78	21.36
Production O&M	3.81	7.52	7.85	16.06	6.94	6.60	48.78
Transmission O&M	0.54	1.03	1.26	1.06	1.19	1.07	6.14
A&G	1.36	2.00	2.42	2.43	2.25	2.16	12.62
Working Capital	(7.58)	12.12	(3.75)	(13.45)	12.40	2.68	2.43
Debt Refunding Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.01	0.00	0.00	0.02
Total Disbursements	9.27	45.72	29.40	27.42	44.20	34.75	190.75
Operating Receipts less Disbursements	11.60	(2.44)	11.58	9.53	(4.89)	8.00	33.39
Capital Expenditures							
Generation	1.24	1.13	3.65	17.54	8.31	0.00	31.86
Transmission	0.03	0.78	0.27	2.65	0.46	0.85	5.03
A&G	0.00	0.11	0.11	0.11	0.11	0.11	0.55
Other (HQ Building, IP)	0.31	0.63	1.73	1.27	1.25	1.27	6.45
Total Capital Expenditures	1.57	2.65	5.76	21.56	10.13	2.23	43.90
Income Taxes from Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Pre-Finance Cash Flow	10.03	(5.09)	5.81	(12.03)	(15.02)	5.77	(10.51)
Financing							
Principal	0.00	0.00	0.00	3.04	0.00	0.00	3.04
Interest	0.63	0.40	0.42	7.79	0.40	1.43	11.08
Line of Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aggregate Debt Service (Incl. Line of Credit)	0.63	0.40	0.42	10.83	0.40	1.43	14.12
Post-Finance Cash Flow	9.40	(5.50)	5.40	(22.85)	(15.42)	4.34	(24.63)
Unwind Transaction							
Cash Proceeds							
Debt Reduction							
Misc. Transaction							
Net Before Member Reserves							
Rural Economic Reserve							
Economic Reserve	1.54	3.23	2.38	1.46	1.93	2.38	(144.09)
Net Before Transition Reserve	1.54	3.23	2.38	1.46	1.93	2.38	107.26
Ending Cash Balances (Incl. Transition Reserve)	124.54	122.28	130.05	108.65	95.16	101.88	
Change in Working Capital							
Other Property	(0.00)	0.00	0.00	0.00	0.00	0.00	(0.00)
Accounts Receivable	6.60	24.09	(3.15)	(4.95)	2.83	3.88	29.30
Materials, Supplies & Other	0.05	0.05	0.05	0.05	0.05	0.05	0.31
Prepayments	0.38	(0.22)	(0.22)	(0.22)	(0.22)	2.78	2.28
Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accounts Payable	(14.46)	(13.04)	(0.15)	(8.06)	9.47	(4.31)	(30.55)
Taxes Accrued	(0.12)	1.27	(0.24)	(0.24)	0.29	0.29	1.26
Other Accruals	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.17)
CoBank Patronage Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	(7.58)	12.12	(3.75)	(13.45)	12.40	2.68	2.43

VI. Credit Measures

Contract TIER	2009 July	2009 August	2009 September	2009 October	2009 November	2009 December	2009 Total
Earnings	0.69	2.65	0.83	(10.39)	0.54	3.09	(2.58)
Plus: Interest Expense, Financing Fees, and Restucturing	2.07	4.11	3.87	4.10	3.95	4.08	22.18
Plus: Imputed Rate Increase In 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Less: Offset to Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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	2009 July	2009 August	2009 September	2009 October	2009 November	2009 December	2009 Total
Calendar Year							
Less: Interest on Sequestered Funds	(0.00)	(0.01)	(0.00)	(0.01)	(0.00)	(0.01)	(0.03)
Total	2.76	6.76	4.70	(6.30)	4.48	7.17	19.57
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	2.76	6.76	4.70	(6.30)	4.48	7.17	19.57
Divided by							
Interest Expense, Financing Fees, and Restucturing	2.07	4.11	3.87	4.10	3.95	4.08	22.18
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	2.07	4.11	3.87	4.10	3.95	4.08	22.18
Contract TIER	1.33	1.64	1.21	(1.54)	1.13	1.76	0.88
Conventional TIER							
Earnings	0.69	2.65	0.83	(10.39)	0.54	3.09	(2.58)
Plus: Interest Expense, Financing Fees, and Restucturing	2.07	4.11	3.87	4.10	3.95	4.08	22.18
Plus Income Tax	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	2.77	6.77	4.70	(6.29)	4.48	7.17	19.59
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	2.77	6.77	4.70	(6.29)	4.48	7.17	19.59
Divided by							
Interest Expense, Financing Fees, and Restructuring	2.07	4.11	3.87	4.10	3.95	4.08	22.18
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	2.07	4.11	3.87	4.10	3.95	4.08	22.18
Conventional TIER	1.33	1.65	1.21	(1.53)	1.14	1.76	0.88
North Star							
Total Cost of Electric Service (millions of $)	22.02	44.48	43.14	49.42	41.32	42.65	243.04
Non-Member Revenues (millions of $)	2.51	5.39	5.34	1.05	4.62	6.93	25.85
	19.51	39.09	37.80	48.37	36.70	35.72	217.18
Smelter and Non-Smelter Member Sales (TWh)	0.46	0.95	0.89	0.89	0.87	0.92	4.98
$/MWh	42.52	41.14	42.40	54.57	42.19	38.68	43.61
$/kWh	0.042524	0.041142	0.042401	0.054572	0.042191	0.038683	0.043613

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Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
I. Sales (TWH)													
Rural	0.25	0.22	0.20	0.16	0.16	0.20	0.23	0.23	0.18	0.16	0.19	0.24	2.41
Large Industrial	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.07	0.08	0.96
Century	0.35	0.32	0.35	0.34	0.35	0.34	0.35	0.35	0.34	0.35	0.34	0.35	4.14
Alcan	0.27	0.24	0.27	0.26	0.27	0.26	0.27	0.27	0.26	0.27	0.26	0.27	3.16
Market	0.08	0.03	0.06	0.09	0.05	0.01	0.07	0.06	0.02	0.04	0.08	0.13	0.72
Total Sales	1.03	0.88	0.95	0.93	0.92	0.90	0.99	1.00	0.88	0.90	0.94	1.07	11.39
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)													
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Rural													
Load Factor (%)	63.71%	65.66%	68.09%	62.86%	61.83%	61.19%	62.49%	52.36%	55.68%	64.25%	63.76%	68.00%	
Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	
Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	
Net Rate ($/ MWH)	36.25	35.78	35.23	36.46	36.73	36.90	36.56	36.59	38.53	36.11	36.23	35.25	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	8.50	8.83	9.06	9.38	9.34	9.40	9.78	9.93	9.66	9.84	9.66	9.83	
Environmental Surcharge	2.64	2.72	2.80	2.51	2.71	3.02	2.92	3.04	3.23	3.16	2.93	2.73	
Surcredit	(2.98)	(3.06)	(3.54)	(4.00)	(3.89)	(3.32)	(3.15)	(3.04)	(3.53)	(4.03)	(3.65)	(3.03)	
Total	8.16	8.49	8.32	7.89	8.15	9.11	9.54	9.93	9.36	8.97	8.93	9.53	
Economic Reserve	(8.16)	(8.49)	(8.32)	(7.89)	(8.15)	(9.11)	(7.54)	(7.93)	(7.36)	(6.97)	(6.93)	(7.53)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	36.25	35.78	35.23	36.46	36.73	36.90	38.56	38.59	40.53	38.11	38.23	37.25	
Large Industrial													
Load Factor (%)	78.11%	74.67%	74.44%	78.35%	80.10%	79.31%	73.03%	83.04%	84.04%	79.59%	71.88%	75.93%	
Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	
Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	
Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net Rate ($/ MWH)	31.52	32.34	32.39	31.46	31.07	31.25	32.75	30.46	30.26	31.18	33.06	32.03	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	8.50	8.83	9.06	9.38	9.34	9.40	9.78	9.93	9.66	9.84	9.66	9.83	
Environmental Surcharge	2.64	2.72	2.80	2.51	2.71	3.02	2.92	3.04	3.23	3.16	2.93	2.73	
Surcredit	(2.98)	(3.06)	(3.54)	(4.00)	(3.89)	(3.32)	(3.15)	(3.04)	(3.53)	(4.03)	(3.65)	(3.03)	
PCA - Net	8.16	8.49	8.32	7.89	8.15	9.11	9.54	9.93	9.36	8.97	8.93	9.53	
Economic Reserve	(8.16)	(8.49)	(8.32)	(7.89)	(8.15)	(9.11)	(7.54)	(7.93)	(7.36)	(6.97)	(6.93)	(7.53)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	31.52	32.34	32.39	31.46	31.07	31.25	34.75	32.46	32.26	33.18	35.06	34.03	
Non-Smelter Member Blend													
Net Rate ($/ MWH)	35.08	34.89	34.44	34.78	34.81	35.27	35.62	34.89	35.78	34.44	35.34	34.47	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	8.50	8.83	9.06	9.38	9.34	9.40	9.78	9.93	9.66	9.84	9.66	9.83	
Environmental Surcharge	2.64	2.72	2.80	2.51	2.71	3.02	2.92	3.04	3.23	3.16	2.93	2.73	
Surcredit	(2.98)	(3.06)	(3.54)	(4.00)	(3.89)	(3.32)	(3.15)	(3.04)	(3.53)	(4.03)	(3.65)	(3.03)	
PCA - Net	8.16	8.49	8.32	7.89	8.15	9.11	9.54	9.93	9.36	8.97	8.93	9.53	
Economic Reserve	(8.16)	(8.49)	(8.32)	(7.89)	(8.15)	(9.11)	(7.54)	(7.93)	(7.36)	(6.97)	(6.93)	(7.53)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	35.08	34.69	34.44	34.78	34.81	35.27	37.62	36.89	37.78	36.44	37.34	38.47	

Big Rivers Electric Corporation

	2010	2010	2010	2010	2010	2010	2010	2010	2010	2010	2010	2010	2010
Calendar Year	January	February	March	April	May	June	July	August	September	October	November	December	Total
Smelters													
Base Rate	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	
TIER Adjustment	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	
Smelter Rate Subject to Price Cap	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	
FAC, Non-FAC PPA, ES	10.02	10.51	10.42	10.64	10.61	11.78	12.21	12.37	12.11	11.69	11.08	11.45	
Surcharge 1	0.36	0.40	0.36	0.38	0.36	0.38	0.36	0.38	0.38	0.36	0.38	0.36	
Surcharge 2	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate	41.68	42.22	42.09	42.32	42.28	43.46	43.87	44.04	43.79	43.36	42.76	43.11	
Market	52.03	55.95	55.69	49.57	52.70	55.23	56.12	56.31	53.42	54.99	52.87	51.57	
III. Income Statement													
Electric Energy Revenues	44.25	38.13	40.91	40.15	39.74	39.40	44.74	45.04	39.28	39.33	41.22	47.40	499.60
Income From Leased Property Net	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Operating Revenue and Income	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	7.48
TOTAL OPER. REVENUES & PATRONAGE CAPITAL	44.88	38.76	41.53	40.77	40.37	40.03	45.38	45.66	39.90	39.96	41.85	48.03	507.08
Operating Expense-Production-Excluding Fuel	4.66	4.30	4.82	4.68	4.79	5.03	5.02	4.96	4.92	4.73	4.69	4.82	57.41
Operating Expense-Production-Fuel	14.12	12.14	13.56	13.40	11.69	12.75	15.73	15.58	12.78	11.72	13.12	15.32	161.91
Operating Expense-Other Power Supply	9.73	9.22	10.01	10.60	10.66	10.21	9.41	9.73	9.68	10.72	9.72	10.61	120.30
Operating Expense-Transmission	0.69	0.62	0.66	0.60	0.60	0.65	0.66	0.60	0.82	0.60	0.60	0.65	7.74
Operating Expense-Distribution													
Operating Expense-Customer Accounts													
Operating Expense-Customer Service and Information	0.07	0.05	0.05	0.05	0.05	0.07	0.05	0.06	0.07	0.05	0.05	0.06	0.70
Operating Expense-Sales	0.03	0.02	0.03	0.02	0.02	0.03	0.02	0.02	0.22	0.04	0.05	0.13	0.61
Operating Expense-Administrative and General	2.84	2.42	2.70	2.43	2.25	2.89	2.58	2.26	2.47	2.21	1.91	2.17	29.12
TOTAL OPERATION EXPENSE	32.13	28.76	31.84	31.79	30.05	31.62	33.46	33.22	30.95	30.07	30.14	33.76	377.81
Maintenance Expense-Production	2.28	3.04	3.08	3.57	4.07	3.18	3.05	2.92	3.02	3.22	2.78	2.69	36.90
Maintenance Expense-Transmission	0.34	0.31	0.39	0.34	0.32	0.43	0.43	0.41	0.44	0.30	0.31	0.35	4.37
Maintenance Expense-Distribution													
Maintenance Expense-General Plant	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.05
TOTAL MAINTENANCE EXPENSE	2.62	3.36	3.47	3.91	4.39	3.62	3.49	3.33	3.47	3.52	3.09	3.04	41.32
Depreciation and Amortization Expense	2.88	2.88	2.88	2.88	2.89	2.89	2.90	2.90	2.91	2.92	2.94	2.95	34.83
Taxes	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
Interest on Long-Term Debt	4.29	3.88	4.29	3.99	3.96	3.84	3.97	4.01	3.88	4.02	3.93	4.15	48.24
Interest Charged to Construction - Credit	(0.02)	(0.03)	(0.04)	(0.04)	(0.05)	(0.06)	(0.06)	(0.07)	(0.06)	(0.05)	(0.05)	(0.05)	(0.58)
Other Interest Expense													
Asset Retirement Obligation													
Other Deductions	0.00	0.00	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.10
TOTAL COST OF ELECTRIC SERVICE	41.93	38.88	42.48	42.57	41.28	41.94	43.79	43.43	41.19	40.51	40.09	43.89	501.98
OPERATING MARGINS	2.95	(0.12)	(0.95)	(1.80)	(0.91)	(1.92)	1.57	2.24	(1.29)	(0.55)	1.75	4.14	5.11
Interest Income	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.45
Allowance For Funds Used During Construction													
Income (Loss) From Equity Investments													
Other Non-Operating Income (Net)													
Generation and Transmission Capital Credits													
Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Extraordinary Items													
NET PATRONAGE CAPITAL OR MARGIN	2.98	(0.09)	(0.91)	(1.76)	(0.87)	(1.88)	1.61	2.27	(1.25)	(0.51)	1.79	4.18	5.56
IV. Balance Sheet													
Total Utility Plant In Service	1,987.00	1,989.73	1,993.72	1,999.67	2,003.73	2,009.78	2,014.82	2,019.36	2,022.23	2,023.82	2,025.01	2,025.45	
Construction Work in Progress	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	
Total Utility Plant	1,992.00	1,994.73	1,998.72	2,004.67	2,008.73	2,014.78	2,019.82	2,024.36	2,027.23	2,028.82	2,030.01	2,030.45	
Accum. Provision for Depreciation and Amort.	913.28	916.32	919.35	922.39	925.43	928.47	931.53	934.59	937.66	940.73	943.83	946.94	
NET UTILITY PLANT	1,078.71	1,078.42	1,079.37	1,082.28	1,083.30	1,086.30	1,088.29	1,089.77	1,089.57	1,088.08	1,086.18	1,083.51	

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Big Rivers Electric Corporation

Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
Non-Utility Property (Net)	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	
Invest. In Assoc. Org - Patronage Capital	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	
Invest. In Assoc. - Other - General Funds	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	
Other Investments	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	
Special Funds	35.05	35.08	35.11	35.13	35.16	35.19	35.21	35.24	35.27	35.30	35.32	35.35	
Special Funds (Transition Reserve)	142.77	140.45	138.36	136.67	134.81	132.38	130.23	127.87	126.06	124.55	122.91	120.66	
Special Funds (Economic Reserve)	61.00	61.09	61.18	61.28	61.38	61.47	61.57	61.67	61.76	61.86	61.95	62.05	
Special Funds (Rural Economic Reserve)													
TOTAL OTHER PROPERTY AND INVESTMENTS	243.88	241.68	239.70	238.13	236.40	234.09	232.07	229.84	228.15	226.76	225.24	223.11	
Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Cash - Construction Funds - Trustee	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	
Special Deposits	38.73	47.09	48.98	36.83	38.39	37.96	36.10	39.35	46.43	51.23	55.59	59.14	
Temporary Investments	44.25	38.13	40.91	40.15	39.74	39.40	44.74	45.04	39.28	39.33	41.22	47.40	
Accounts Receivable - Sales of Eergy (Net)	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	
Accounts Receivable - Other (Net)	25.72	26.27	26.61	26.69	26.75	26.85	27.25	27.46	27.29	27.29	27.25	27.45	
Fuel Stock	20.89	20.95	21.00	21.05	21.10	21.16	21.21	21.26	21.31	21.37	21.42	21.47	
Materials and Supplies - Other	6.32	5.76	5.17	4.74	4.47	4.20	3.92	3.65	3.38	3.10	2.83	5.63	
Prepayments	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	
Other Current and Accrued Assets													
TOTAL CURRENT AND ACCRUED ASSETS	139.59	141.86	146.34	133.12	134.13	133.23	136.89	139.42	141.36	145.99	151.98	164.76	
Unamortized Debt Discount & Extraor. Prop. Losses	0.67	0.67	0.66	2.11	2.10	2.09	2.08	2.08	2.07	2.06	2.05	2.04	
Regulatory Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Other Deferred Debits	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.42	
Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL ASSETS AND OTHER DEBITS	1,464.29	1,464.05	1,467.50	1,457.08	1,457.36	1,457.15	1,460.76	1,462.54	1,462.57	1,464.31	1,466.88	1,474.85	
TOTAL MARGINS & EQUITY	394.96	394.87	393.96	392.20	391.32	389.44	391.05	393.33	392.07	391.56	393.36	397.54	
Long-Term Debt - RUS	679.51	679.51	681.08	677.14	677.14	678.75	687.06	687.06	688.71	697.15	697.15	698.82	
Long-Term Debt - Other	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	
TOTAL LONG-TERM DEBT	821.61	821.61	823.18	819.24	819.24	820.85	829.16	829.16	830.81	839.25	839.25	840.92	
Notes Payable	29.18	27.61	29.91	31.19	30.08	30.42	30.65	30.28	29.54	29.17	28.14	30.54	
Accounts Payable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Accounts Payable (TIER Rebate)	0.29	0.57	0.85	1.07	1.36	1.58	1.86	0.37	0.60	0.88	0.47	0.06	
Taxes Accrued	3.14	6.17	7.97	3.02	6.36	8.00	3.04	6.44	8.08	3.05	6.39	8.29	
Interest Accrued	3.56	3.57	3.58	3.59	3.60	3.61	3.62	3.62	3.63	3.64	3.65	3.66	
Other Current and Accrued Liabilities	0.20	0.50	0.90	1.19	1.55	1.73	1.89	2.08	2.29	2.60	2.99	3.35	
Other Current and Accrued Liabilities (Purchased Power)													
TOTAL CURRENT AND ACCRUED LIABILITIES	36.36	38.43	43.20	40.06	42.95	45.34	41.05	42.79	44.13	39.34	41.64	45.90	
Deferred Credits	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Deferred Credits (Economic Reserve)	142.77	140.45	138.36	136.67	134.81	132.38	130.23	127.87	126.06	124.55	122.91	120.66	
Deferred Credits (Rural Economic Reserve)	61.00	61.09	61.18	61.28	61.38	61.47	61.57	61.67	61.76	61.86	61.95	62.05	
Accumulated Operating Provisions	7.58	7.60	7.62	7.64	7.66	7.67	7.69	7.71	7.73	7.75	7.77	7.79	
Obligation under Capital Leases - Noncurrent													
TOTAL LIABILITIES AND OTHER CREDITS	1,464.29	1,464.05	1,467.50	1,457.08	1,457.36	1,457.15	1,460.76	1,462.54	1,462.57	1,464.31	1,466.88	1,474.85	
V. Cash Flow Statement													
Operating Receipts													
Rural	8.90	7.79	6.98	5.72	6.05	7.49	8.95	8.88	7.24	6.05	7.11	9.05	90.21
Large Industrial	2.53	2.43	2.45	2.50	2.63	2.57	2.62	2.87	2.87	2.72	2.56	2.63	31.36
Smelters	25.83	23.63	26.08	25.38	26.20	26.06	27.19	27.29	26.27	26.87	25.65	26.72	313.18
Offsystem	4.33	1.79	3.11	4.68	2.84	0.68	3.66	3.47	0.93	2.01	4.11	6.59	38.22
Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cobank Patronage Capital & Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
Interest Earnings	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.45
Total Receipts	41.63	35.68	38.67	38.32	37.75	36.84	42.46	42.55	37.35	37.70	39.47	45.03	473.44

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Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
Operating Disbursements													
PPA													
Fuel Costs	17.67	14.89	18.49	14.42	14.12	15.09	18.34	18.07	14.93	14.16	15.48	18.06	191.71
Fuel Costs (Labor & Exp)	0.38	0.37	0.42	0.40	0.42	0.43	0.46	0.46	0.40	0.41	0.40	0.39	4.94
Domtar	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)
Power Supply (Purch. Power, APM, Cogen, & TVA Tran)	5.86	5.56	5.84	8.20	6.74	6.56	5.81	6.01	5.97	6.78	5.76	6.55	75.66
Production O&M	6.93	7.35	7.90	8.25	8.85	8.21	8.07	7.88	7.94	7.94	7.47	7.51	94.31
Transmission O&M	1.02	0.93	1.05	0.94	0.92	1.09	1.09	1.01	1.26	0.90	0.91	1.00	12.11
A&G	2.94	2.49	2.79	2.51	2.32	2.99	2.66	2.34	2.77	2.30	2.01	2.36	30.48
Working Capital	(1.11)	(5.07)	(0.03)	(2.50)	0.19	(1.13)	4.59	1.92	(5.47)	(0.10)	3.10	7.03	1.43
Debt Refunding Cost	0.00	0.00	0.00	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.45
Other	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
Total Disbursements	33.70	26.52	34.46	33.68	33.56	33.26	41.01	37.71	27.79	32.40	35.12	42.89	412.10
Operating Receipts less Disbursements	7.93	9.16	4.21	4.64	4.19	3.58	1.44	4.84	9.55	5.30	4.34	2.14	61.34
Capital Expenditures													
Generation	0.25	0.41	1.12	3.31	1.40	3.45	2.89	3.12	2.04	1.00	0.70	0.02	19.71
Transmission	1.21	1.59	1.91	1.98	1.87	1.81	1.41	1.30	0.76	0.49	0.42	0.36	15.09
A&G	0.27	0.09	0.30	0.02	0.12	0.03	0.02	0.02	0.02	0.05	0.02	0.02	0.95
Other (HQ Building, IP)	0.61	0.62	0.62	0.62	0.62	0.70	0.65	0.04	0.00	0.00	0.00	0.00	4.49
Total Capital Expenditures	2.34	2.71	3.95	5.90	4.01	5.99	4.97	4.47	2.82	1.53	1.15	0.39	40.24
Income Taxes from Operations	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
Net Pre-Finance Cash Flow	5.57	6.44	0.24	(1.28)	0.16	(2.43)	(3.55)	0.35	6.71	3.75	3.18	1.73	20.85
Financing													
Principal	26.94	0.00	0.00	3.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.87
Interest	9.38	0.54	0.60	8.77	0.60	0.58	0.60	0.60	0.58	0.60	0.58	0.56	23.98
Line of Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aggregate Debt Service (Incl. Line of Credit)	36.32	0.54	0.60	12.71	0.60	0.58	0.60	0.60	0.58	0.60	0.58	0.56	54.86
Post-Finance Cash Flow	(30.75)	5.90	(0.36)	(13.99)	(0.44)	(3.00)	(4.15)	(0.25)	6.14	3.15	2.60	1.16	(34.00)
Unwind Transaction													
Cash Proceeds													
Debt Reduction													
Misc. Transaction													
Net Before Member Reserves													
Rural Economic Reserve													
Economic Reserve	2.66	2.49	2.28	1.86	2.03	2.60	2.32	2.52	1.97	1.68	1.80	2.41	26.62
Net Before Transition Reserve	2.66	2.49	2.28	1.86	2.03	2.60	2.32	2.52	1.97	1.68	1.80	2.41	26.62
Ending Cash Balances (Incl. Transition Reserve)	73.79	82.17	84.09	71.96	73.55	73.15	71.32	73.59	81.70	86.52	90.92	94.49	
Change in Working Capital													
Other Property	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accounts Receivable	(0.85)	(6.12)	2.78	(0.76)	(0.40)	(0.34)	5.34	0.30	(5.76)	0.05	1.89	6.18	2.30
Materials, Supplies & Other	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.63
Prepayments	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	2.82	0.00
Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accounts Payable	0.25	1.57	(2.29)	(1.28)	1.11	(0.34)	(0.23)	0.37	0.74	0.36	1.03	(2.40)	(1.10)
Taxes Accrued	(0.28)	(0.28)	(0.28)	(0.22)	(0.28)	(0.22)	(0.28)	1.49	(0.22)	(0.28)	0.41	0.41	(0.06)
Other Accruals	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.34)
CoBank Patronage Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	(1.11)	(5.07)	(0.03)	(2.50)	0.19	(1.13)	4.59	1.92	(5.47)	(0.10)	3.10	7.03	1.43
VI. Credit Measures													
Contract TIER													
Earnings	2.98	(0.09)	(0.91)	(1.76)	(0.87)	(1.88)	1.61	2.27	(1.25)	(0.51)	1.79	4.18	5.56
Plus: Interest Expense, Financing Fees, and Restucturing	4.27	3.85	4.26	3.95	3.91	3.78	3.91	3.95	3.83	3.97	3.89	4.11	47.66
Plus: Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Less: Offset to Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
Less: Interest on Sequestered Funds	(0.03)	(0.02)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.32)
Total	7.23	3.74	3.32	2.16	3.01	1.87	5.49	6.19	2.55	3.43	5.65	8.26	52.90
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	7.23	3.74	3.32	2.16	3.01	1.87	5.49	6.19	2.55	3.43	5.65	8.26	52.90
Divided by													
Interest Expense, Financing Fees, and Restructuring	4.27	3.85	4.26	3.95	3.91	3.78	3.91	3.95	3.83	3.97	3.89	4.11	47.66
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	4.27	3.85	4.26	3.95	3.91	3.78	3.91	3.95	3.83	3.97	3.89	4.11	47.66
Contract TIER	1.69	0.97	0.78	0.55	0.77	0.49	1.41	1.57	0.67	0.86	1.45	2.01	1.11
Conventional TIER													
Earnings	2.98	(0.09)	(0.91)	(1.76)	(0.87)	(1.88)	1.61	2.27	(1.25)	(0.51)	1.79	4.18	5.56
Plus: Interest Expense, Financing Fees, and Restucturing	4.27	3.85	4.26	3.95	3.91	3.78	3.91	3.95	3.83	3.97	3.89	4.11	47.66
Plus Income Tax	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
Total	7.28	3.78	3.37	2.20	3.06	1.92	5.54	6.24	2.60	3.48	5.70	8.31	53.47
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	7.28	3.78	3.37	2.20	3.06	1.92	5.54	6.24	2.60	3.48	5.70	8.31	53.47
Divided by													
Interest Expense, Financing Fees, and Restructuring	4.27	3.85	4.26	3.95	3.91	3.78	3.91	3.95	3.83	3.97	3.89	4.11	47.66
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	4.27	3.85	4.26	3.95	3.91	3.78	3.91	3.95	3.83	3.97	3.89	4.11	47.66
Conventional TIER	1.70	0.98	0.79	0.56	0.78	0.51	1.42	1.58	0.68	0.88	1.47	2.02	1.12
North Star													
Total Cost of Electric Service (millions of $)	41.93	38.88	42.48	42.57	41.28	41.94	43.79	43.43	41.19	40.51	40.09	43.89	501.98
Non-Member Revenues (millions of $)	4.99	2.45	3.78	5.34	3.50	1.34	4.32	4.14	1.59	2.68	4.78	7.26	46.15
	36.94	36.43	38.71	37.23	37.78	40.60	39.47	39.29	39.60	37.83	35.32	36.63	455.82
Smelter and Non-Smelter Member Sales (TWh)	0.95	0.85	0.89	0.84	0.87	0.88	0.93	0.94	0.87	0.86	0.86	0.94	10.67
$/MWh	39.07	42.72	43.31	44.53	43.48	45.88	42.57	41.88	45.68	43.97	41.13	38.97	42.71
$/kWh	0.039070	0.042725	0.043314	0.044530	0.043479	0.045883	0.042567	0.041879	0.045656	0.043971	0.041130	0.038970	0.042706

Calendar Year	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
I. Sales (TWH)													
Rural	0.25	0.22	0.20	0.16	0.17	0.21	0.23	0.24	0.19	0.16	0.19	0.25	2.46
Large Industrial	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.95
Century	0.35	0.32	0.35	0.34	0.35	0.34	0.35	0.35	0.34	0.35	0.34	0.35	4.14
Alcan	0.27	0.24	0.27	0.26	0.27	0.26	0.27	0.27	0.26	0.27	0.26	0.27	3.16
Market	0.10	0.09	0.11	0.10	0.09	0.08	0.07	0.07	0.10	0.14	0.13	0.11	1.20
Total Sales	1.05	0.95	1.01	0.94	0.96	0.97	1.00	1.01	0.97	1.01	0.99	1.06	11.91
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)													
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Rural													
Load Factor (%)	64.22%	65.73%	66.71%	64.17%	62.62%	61.95%	60.94%	64.09%	58.63%	64.32%	63.07%	68.21%	
Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	
Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	
Net Rate ($/ MWH)	36.12	35.76	35.53	36.13	36.52	36.70	36.97	36.15	37.62	36.10	36.41	35.20	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	10.84	11.33	11.72	11.68	11.85	12.03	12.02	12.07	12.06	12.01	12.04	11.75	
Environmental Surcharge	2.88	2.93	2.81	2.72	2.50	2.61	2.91	2.91	3.01	2.86	2.82	2.79	
Surcredit	(2.95)	(3.03)	(3.50)	(3.96)	(3.85)	(3.28)	(3.12)	(3.01)	(3.50)	(3.99)	(3.62)	(3.00)	
Total	10.77	11.22	11.03	10.44	10.49	11.35	11.81	11.96	11.56	10.88	11.24	11.54	
Economic Reserve	(8.77)	(9.22)	(9.03)	(8.44)	(8.49)	(9.35)	(7.81)	(7.96)	(7.56)	(6.88)	(7.24)	(7.54)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	38.12	37.76	37.53	38.13	38.52	38.70	40.97	40.15	41.62	40.10	40.41	39.20	
Large Industrial													
Load Factor (%)	76.12%	74.47%	78.57%	75.32%	78.60%	77.19%	78.94%	80.07%	76.99%	79.87%	74.00%	75.14%	
Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	
Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	
Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net Rate ($/ MWH)	31.98	32.39	31.41	32.18	31.41	31.73	31.33	31.08	31.77	31.12	32.50	32.22	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	10.84	11.33	11.72	11.68	11.85	12.03	12.02	12.07	12.06	12.01	12.04	11.75	
Environmental Surcharge	2.88	2.93	2.81	2.72	2.50	2.61	2.91	2.91	3.01	2.86	2.82	2.79	
Surcredit	(2.95)	(3.03)	(3.50)	(3.96)	(3.85)	(3.28)	(3.12)	(3.01)	(3.50)	(3.99)	(3.62)	(3.00)	
PCA - Net	10.77	11.22	11.03	10.44	10.49	11.35	11.81	11.96	11.56	10.88	11.24	11.54	
Economic Reserve	(8.77)	(9.22)	(9.03)	(8.44)	(8.49)	(9.35)	(7.81)	(7.96)	(7.56)	(6.88)	(7.24)	(7.54)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	33.98	34.39	33.41	34.18	33.41	33.73	35.33	35.08	35.77	35.12	36.50	36.22	
Non-Smelter Member Blend													
Net Rate ($/ MWH)	35.14	34.90	34.34	34.87	34.84	35.32	35.49	34.85	35.90	34.42	35.29	34.50	
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	10.84	11.33	11.72	11.68	11.85	12.03	12.02	12.07	12.06	12.01	12.04	11.75	
Environmental Surcharge	2.88	2.93	2.81	2.72	2.50	2.61	2.91	2.91	3.01	2.86	2.82	2.79	
Surcredit	(2.95)	(3.03)	(3.50)	(3.96)	(3.85)	(3.28)	(3.12)	(3.01)	(3.50)	(3.99)	(3.62)	(3.00)	
PCA - Net	10.77	11.22	11.03	10.44	10.49	11.35	11.81	11.96	11.56	10.88	11.24	11.54	
Economic Reserve	(8.77)	(9.22)	(9.03)	(8.44)	(8.49)	(9.35)	(7.81)	(7.96)	(7.56)	(6.88)	(7.24)	(7.54)	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate ($/ MWH)	37.14	36.90	36.34	36.87	36.84	37.32	39.49	38.85	39.90	38.42	39.29	38.50	

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Big Rivers Electric Corporation

	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
Calendar Year	January	February	March	April	May	June	July	August	September	October	November	December	Total
Smelters													
Base Rate	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	
TIER Adjustment	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	
Smelter Rate Subject to Price Cap	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	
FAC, Non-FAC PPA, ES	12.66	13.00	13.97	13.32	12.74	14.37	14.52	14.71	14.06	13.00	13.13	13.45	
Surcharge 1	0.36	0.40	0.38	0.38	0.36	0.38	0.36	0.36	0.38	0.36	0.38	0.36	
Surcharge 2	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Effective Rate	44.32	44.71	45.64	45.00	44.41	46.05	46.19	46.37	45.74	44.67	44.81	45.12	
Market	62.83	63.45	55.94	53.56	51.63	49.52	60.41	59.06	51.45	56.42	57.29	57.37	
III. Income Statement													
Electric Energy Revenues	48.88	44.60	47.19	43.30	43.63	44.96	47.67	47.92	45.16	46.84	46.44	49.44	556.03
Income From Leased Property Net	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Operating Revenue and Income	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	7.48
TOTAL OPER. REVENUES & PATRONAGE CAPITAL	49.50	45.22	47.81	43.92	44.25	45.59	48.29	48.54	45.78	47.46	47.07	50.06	563.51
Operating Expense-Production-Excluding Fuel	5.06	4.75	5.19	5.10	4.98	5.05	5.19	5.03	5.17	4.89	5.08	5.01	60.50
Operating Expense-Production-Fuel	17.30	16.17	16.13	14.67	14.81	16.65	17.81	18.03	16.42	17.20	16.65	17.39	199.24
Operating Expense-Other Power Supply	9.56	8.73	11.90	12.54	12.26	10.04	9.65	9.95	9.88	9.43	9.63	10.46	124.04
Operating Expense-Transmission	0.69	0.64	0.68	0.62	0.62	0.67	0.68	0.68	0.80	0.63	0.66	0.61	7.99
Operating Expense-Distribution													
Operating Expense-Customer Accounts													
Operating Expense-Customer Service and Information	0.07	0.06	0.07	0.06	0.06	0.07	0.08	0.07	0.09	0.06	0.06	0.05	0.74
Operating Expense-Sales	0.14	0.13	0.14	0.13	0.13	0.14	0.13	0.13	0.34	0.14	0.13	0.13	1.80
Operating Expense-Administrative and General	2.47	2.11	2.54	2.26	2.19	2.87	2.53	2.23	2.33	2.19	2.11	2.16	28.09
TOTAL OPERATION EXPENSE	35.29	32.59	36.65	35.38	35.04	35.49	36.05	36.14	35.00	34.54	34.33	35.82	422.31
Maintenance Expense-Production	2.73	3.77	8.28	6.60	6.37	3.05	3.23	3.08	3.15	3.55	3.07	2.63	49.52
Maintenance Expense-Transmission	0.34	0.33	0.41	0.32	0.32	0.44	0.46	0.48	0.42	0.32	0.36	0.31	4.51
Maintenance Expense-Distribution													
Maintenance Expense-General Plant	0.02	0.02	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.16
TOTAL MAINTENANCE EXPENSE	3.08	4.11	8.71	6.94	6.70	3.50	3.71	3.57	3.59	3.89	3.44	2.95	54.19
Depreciation and Amortization Expense	2.96	2.97	2.97	2.98	2.99	3.00	3.03	3.03	3.04	3.05	3.05	3.05	36.09
Taxes	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
Interest on Long-Term Debt	4.05	3.66	4.05	3.91	4.04	3.91	4.03	4.03	3.90	4.02	3.89	4.02	47.54
Interest Charged to Construction - Credit	(0.05)	(0.07)	(0.08)	(0.10)	(0.12)	(0.14)	(0.15)	(0.16)	(0.13)	(0.12)	(0.11)	(0.11)	(1.32)
Other Interest Expense													
Asset Retirement Obligation													
Other Deductions	0.01	0.01	0.01	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.12
TOTAL COST OF ELECTRIC SERVICE	45.37	43.29	52.33	49.16	48.68	45.80	46.70	46.64	45.42	45.41	44.63	45.77	559.18
OPERATING MARGINS	4.14	1.93	(4.52)	(5.23)	(4.43)	(0.21)	1.59	1.90	0.36	2.06	2.44	4.30	4.33
Interest Income	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.43
Allowance For Funds Used During Construction													
Income (Loss) From Equity Investments													
Other Non-Operating Income (Net)													
Generation and Transmission Capital Credits													
Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Extraordinary Items													
NET PATRONAGE CAPITAL OR MARGIN	4.18	1.97	(4.47)	(5.20)	(4.39)	(0.18)	1.62	1.93	0.40	2.09	2.47	4.33	4.75
IV. Balance Sheet													
Total Utility Plant In Service	2,030.75	2,034.74	2,042.50	2,052.93	2,062.86	2,068.76	2,072.55	2,077.18	2,085.56	2,086.79	2,087.64	2,088.22	
Construction Work In Progress	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	
Total Utility Plant	2,035.75	2,039.74	2,047.50	2,057.93	2,067.86	2,073.76	2,077.55	2,082.18	2,090.56	2,091.79	2,092.64	2,093.22	
Accum. Provision for Depreciation and Amort.	950.05	953.18	956.30	959.44	962.59	965.75	968.94	972.13	975.34	978.55	981.76	984.98	
NET UTILITY PLANT	1,085.69	1,086.56	1,091.20	1,098.49	1,105.27	1,108.01	1,108.61	1,110.04	1,115.22	1,113.24	1,110.88	1,108.24	

Big Rivers Electric Corporation

Calendar Year	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
Non-Utility Property (Net)													
Invest. In Assoc. Org - Patronage Capital	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	
Invest. In Assoc. - Other - General Funds	0.68	0.68	0.68	0 68	0.88	0 68	0.68	0.68	0.68	0 68	0 68	0.68	
Other Investments	0.02	0.02	0.02	0.02	0 02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	
Special Funds	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0 78	0.78	0.78	
Special Funds (Transition Reserve)	35.38	35.40	35.43	35.46	35.49	35.51	35.54	35.57	35.60	35.62	35.65	35.68	
Special Funds (Economic Reserve)	117.93	115.34	112.99	111.12	109.12	106.56	104.28	101.85	99.94	98.39	96.62	94.31	
Special Funds (Rural Economic Reserve)	62.15	62.24	62.34	62.43	62.53	62.63	62.73	62.83	62.93	63.03	63.12	63.22	
TOTAL OTHER PROPERTY AND INVESTMENTS	220.51	218.03	215.81	214.06	212.19	209.76	207.60	205.30	203.51	202.09	200.45	198.28	
Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Cash - Construction Funds - Trustee													
Special Deposits	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	
Temporary Investments	51.22	58.99	59.39	40.22	32.85	29.30	18.88	20.62	22 30	16.44	24.97	30.29	
Accounts Receivable - Sales of Eergy (Net)	48.88	44.60	47.19	43.30	43.63	44.96	47.67	47.92	45.16	46.84	46.44	49.44	
Accounts Receivable - Other (Net)	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0 85	0 85	0.85	0.85	0.85	
Fuel Stock	28.58	29.22	29.74	29.77	29.72	29.73	29.92	30.03	30.05	30.07	30.10	29.78	
Materials and Supplies - Other	21.53	21.58	21.64	21.69	21.74	21.80	21.85	21.91	21.96	22.02	22.07	22.13	
Prepayments	5.35	5.07	4.79	4.51	4.23	3.95	3.67	3.39	3.11	2.83	2.55	5.50	
Other Current and Accrued Assets	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	
TOTAL CURRENT AND ACCRUED ASSETS	159.23	163.13	166.41	143.16	135.84	133.41	125.45	127.53	126.26	121.88	129.81	140.78	
Unamortized Debt Discount & Extraor. Prop. Losses	2.04	2.03	2.02	2.01	2.00	2.00	1.99	1.98	1.97	1.96	1.95	1.95	
Regulatory Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Other Deferred Debits	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	
Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL ASSETS AND OTHER DEBITS	1,468.89	1,471.18	1,476.86	1,459.15	1,456.73	1,454.60	1,445.07	1,446.28	1,448.38	1,440.58	1,444.51	1,450.65	
TOTAL MARGINS & EQUITY	401.71	403.69	399.21	394.02	389.63	389.45	391.07	393.00	393.40	395.49	397.96	402.29	
Long-Term Debt - RUS	695.40	695.40	697.05	693.02	693.02	694.72	690.91	690.91	692.66	689.07	689.07	690.83	
Long-Term Debt - Other	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	
TOTAL LONG-TERM DEBT	837.50	837.50	839.15	835.12	835.12	836.82	833.01	833.01	834.76	831.17	831.17	832.93	
Notes Payable													
Accounts Payable	31.05	30.07	38.56	36.35	36.08	32.92	32.27	32.11	31.79	31.15	30.81	31.34	
Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Taxes Accrued	0 29	0.58	0.88	1.11	1.40	1.63	1.92	0.14	0.37	0.68	0.36	0.06	
Interest Accrued	3.08	6.19	7.97	2.96	6.39	8.00	3.08	6.48	8.04	3.05	6.35	7.99	
Other Current and Accrued Liabilities	3.67	3.68	3.69	3.70	3.71	3.72	3.73	3.73	3.74	3.75	3.76	3.77	
Other Current and Accrued Liabilities (Purchased Power)	3.70	4.07	4.22	4.48	4.88	4.96	5.09	5.17	5.44	5.90	6.35	6.70	
TOTAL CURRENT AND ACCRUED LIABILITIES	41.79	44.59	55.32	48.59	52.44	51.23	46.05	47.63	49.39	44.52	47.64	49.87	
Deferred Credits	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Deferred Credits (Economic Reserve)	117.93	115.34	112.99	111.12	109.12	106.56	104.28	101.85	99.94	98.39	96.62	94.31	
Deferred Credits (Rural Economic Reserve)	62 15	62.24	62.34	62.43	62 53	62 63	62.73	62.83	62.93	03.03	63.12	63.22	
Accumulated Operating Provisions	7.81	7.83	7.85	7.87	7.89	7.91	7.93	7.95	7.97	7.99	8.01	8.03	
Obligation under Capital Leases - Noncurrent													
TOTAL LIABILITIES AND OTHER CREDITS	1,468.89	1,471.18	1,476.86	1,459.15	1,450.73	1,454.60	1,445.07	1,446.28	1,448.38	1,440.58	1,444.51	1,450.65	
V. Cash Flow Statement													
Operating Receipts													
Rural	9.56	8.34	7.38	6.19	6.50	8.05	9.39	9.61	7.93	6.45	7.53	9.69	96.63
Large Industrial	2.66	2.58	2.67	2.61	2.77	2.70	2.87	2.89	2.85	2.89	2.74	2.77	32.99
Smelters	27.47	25.02	28.28	26.99	27.52	27.62	28.62	28.74	27.43	27.68	26.87	27.96	330.23
Offsystem	6.30	5.93	6.35	5.49	4.70	3.90	4.35	4.12	4.90	8.15	7.40	6.59	68.17
Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00
Cobank Patronage Capital & Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
Interest Earnings	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.43
Total Receipts	46.04	41.91	44.73	41.32	41.53	42.30	45.27	45.39	43.15	45.20	44.58	47.04	528.47

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Big Rivers Electric Corporation

Calendar Year	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
Operating Disbursements													
PPA													
Fuel Costs	21.10	19.23	19.44	17.29	18.62	17.48	20.50	20.64	18.92	19.90	19.27	19.84	230.23
Fuel Costs (Labor & Exp)	0.38	0.37	0.53	0.43	0.44	0.47	0.44	0.52	0.40	0.41	0.40	0.39	5.18
Domtar	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)
Power Supply (Purch. Power, APM, Cogen, & TVA Tran)	5.39	4.78	7.66	8.48	8.76	7.89	5.79	6.08	5.94	5.11	5.41	6.14	77.43
Production O&M	7.78	8.52	13.48	11.70	11.35	8.10	8.42	8.11	8.33	8.44	8.14	7.64	110.02
Transmission O&M	1.02	0.98	1.09	0.95	0.94	1.10	1.14	1.16	1.22	0.95	1.02	0.92	12.50
A&G	2.70	2.31	2.75	2.46	2.38	3.10	2.74	2.45	2.73	2.40	2.32	2.38	30.70
Working Capital	0.50	(3.83)	(6.44)	(2.14)	0.09	4.01	2.83	1.95	(2.91)	1.79	0.01	5.76	1.62
Debt Refunding Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
Total Disbursements	38.87	32.38	38.51	39.19	40.58	42.15	41.86	40.90	34.63	39.00	36.57	43.05	467.67
Operating Receipts less Disbursements	7.16	9.55	6.23	2.13	0.95	0.15	3.41	4.49	8.52	6.21	8.01	3.99	60.80
Capital Expenditures													
Generation	3.78	2.26	6.19	8.51	8.30	4.14	3.15	3.98	7.79	0.61	0.18	0.02	48.90
Transmission	1.27	1.63	1.36	1.72	1.49	1.49	0.47	0.47	0.45	0.45	0.54	0.45	11.79
A&G	0.20	0.04	0.13	0.10	0.02	0.13	0.02	0.02	0.02	0.05	0.02	0.00	0.76
Other (HQ Building, IP)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Capital Expenditures	5.25	3.92	7.68	10.33	9.81	5.77	3.64	4.47	8.25	1.11	0.75	0.47	61.45
Income Taxes from Operations	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
Net Pre-Finance Cash Flow	1.89	5.61	(1.47)	(8.22)	(8.89)	(5.64)	(0.25)	0.01	0.24	5.08	7.24	3.51	(0.90)
Financing													
Principal	3.42	0.00	0.00	4.03	0.00	0.00	3.81	0.00	0.00	3.59	0.00	0.00	14.85
Interest	9.24	0.54	0.60	8.91	0.60	0.58	8.96	0.60	0.58	8.99	0.58	0.60	40.77
Line of Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aggregate Debt Service (Incl. Line of Credit)	12.67	0.54	0.60	12.93	0.60	0.58	12.77	0.60	0.58	12.59	0.58	0.60	55.62
Post-Finance Cash Flow	(10.78)	5.07	(2.07)	(21.16)	(9.48)	(6.21)	(13.02)	(0.59)	(0.34)	(7.51)	6.67	2.91	(56.52)
Unwind Transaction													
Cash Proceeds													
Debt Reduction													
Misc. Transaction													
Net Before Member Reserves													
Rural Economic Reserve													
Economic Reserve	2.89	2.73	2.50	2.01	2.14	2.69	2.43	2.56	2.04	1.67	1.89	2.44	27.99
Net Before Transition Reserve	2.89	2.73	2.50	2.01	2.14	2.69	2.43	2.56	2.04	1.67	1.89	2.44	27.99
Ending Cash Balances (Incl. Transition Reserve)	86.60	94.40	94.82	75.68	68.34	64.82	54.22	56.19	57.90	52.06	60.62	65.97	
Change in Working Capital													
Other Property	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accounts Receivable	1.48	(4.28)	2.59	(3.89)	0.33	1.33	2.70	0.25	(2.76)	1.68	(0.40)	3.00	2.04
Materials, Supplies & Other	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.65
Prepayments	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	2.97	0.08
Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accounts Payable	(0.51)	0.98	(8.50)	2.21	0.29	3.14	0.66	0.16	0.31	0.64	0.34	(0.53)	(0.81)
Taxes Accrued	(0.23)	(0.29)	(0.29)	(0.23)	(0.29)	(0.23)	(0.29)	1.77	(0.23)	(0.29)	0.30	0.30	(0.00)
Other Accruals	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.35)
CoBank Patronage Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.50	(3.83)	(6.44)	(2.14)	0.09	4.01	2.83	1.95	(2.91)	1.79	0.01	5.76	1.62
VI. Credit Measures													
Contract TIER													
Earnings	4.18	1.97	(4.47)	(5.20)	(4.39)	(0.18)	1.62	1.93	0.40	2.09	2.47	4.33	4.75
Plus: Interest Expense, Financing Fees, and Restucturing	4.00	3.60	3.97	3.81	3.93	3.78	3.89	3.88	3.77	3.90	3.79	3.91	46.22
Plus: Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Less: Offset to Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
Calendar Year													
Less: Interest on Sequestered Funds	(0.03)	(0.02)	(0.03)	(0.03)	(0.03)	(0 03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.33)
Total	8.15	5.54	(0.53)	(1.41)	(0.49)	3.57	5.48	5.78	4.14	5.96	6 23	8.22	50.65
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	8.15	5 54	(0.53)	(1.41)	(0.49)	3.57	5.48	5.78	4.14	5.96	6.23	8.22	50.65
Divided by													
Interest Expense, Financing Fees, and Restructuring	4 00	3 60	3.97	3.81	3 93	3 78	3.89	3.88	3.77	3.90	3.79	3.91	46.22
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	4.00	3.60	3.97	3.81	3.93	3.78	3.89	3.88	3.77	3.90	3.79	3.91	46.22
Contract TIER	2.04	1.54	(0.13)	(0.37)	(0.13)	0.95	1.41	1.49	1.10	1.53	1.65	2.10	1.10
Conventional TIER													
Earnings	4 18	1.97	(4.47)	(5.20)	(4 39)	(0.18)	1.62	1.93	0 40	2.09	2 47	4 33	4.75
Plus: Interest Expense, Financing Fees, and Restucturing	4.00	3.60	3.97	3.81	3.93	3.78	3.89	3.88	3 77	3.90	3 79	3.91	46.22
Plus Income Tax	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
Total	8.20	5.59	(0.48)	(1.37)	(0.45)	3 62	5.53	5.83	4.19	6.01	6.28	8.27	51.22
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	8.20	5.59	(0.48)	(1.37)	(0.45)	3.62	5.53	5.83	4.19	6.01	6.28	8.27	51.22
Divided by													
Interest Expense, Financing Fees, and Restructuring	4.00	3.60	3 97	3.81	3.93	3 78	3.89	3 88	3.77	3.90	3.79	3.91	46.22
Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	4.00	3.60	3.97	3.81	3.93	3.78	3.89	3.88	3.77	3.90	3.79	3.91	46.22
Conventional TIER	2.05	1.55	(0.12)	(0.36)	(0.11)	0.95	1.42	1.50	1.11	1.54	1.66	2.11	1.11
North Star													
Total Cost of Electric Service (millions of $)	45.37	43.29	52.33	49.16	48.68	45.80	46.70	46.64	45.42	45.41	44 63	45.77	559.18
Non-Member Revenues (millions of $)	6.97	6.59	7.02	6.15	5.36	4.55	5.00	4.77	5.55	8.81	8.06	7.24	76.07
	38.40	36.70	45.31	43.00	43.32	41.24	41.70	41.87	39.87	36.60	36.57	38.52	483.11
Smelter and Non-Smelter Member Sales (TWh)	0.95	0.86	0.90	0.84	0.87	0.89	0.93	0.94	0.87	0 85	0.86	0 94	10.71
$/MWh	40.47	42.89	50.55	51 29	49.72	46.45	44.82	44.47	45.82	42 42	42.47	40.84	45.12
$/kWh	0.040472	0.042893	0.050549	0.051288	0.049715	0.046453	0.044817	0.044474	0.045821	0.042425	0.042466	0.040842	0.045118

Calendar Year	2012
i. Sales (TWH)	
Rural	2.50
Large Industrial	0.95
Century	4.15
Alcan	3.17
Market	1.09
Total Sales	11.85
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)	
General Rate Adjustment (%)	11.12%
Rural	
Load Factor (%)	63.61%
Demand ($/ KW-mo.)	8.19
Energy ($/ MWH)	22.67
Net Rate ($/ MWH)	40.26
MRDA	0.00
Regulatory Charge	(0.65)
FAC	15.35
Environmental Surcharge	2.84
Surcredit	(3.97)
Total	14.22
Economic Reserve	(9.22)
TIER Related Rebate	0.00
Effective Rate ($/ MWH)	44.61
Large Industrial	
Load Factor (%)	76.91%
Demand ($/ KW-mo.)	11.28
Energy ($/ MWH)	15.24
Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00
Net Rate ($/ MWH)	35.27
MRDA	0.00
Regulatory Charge	(0.65)
FAC	15.35
Environmental Surcharge	2.84
Surcredit	(3.97)
PCA - Net	14.22
Economic Reserve	(9.22)
TIER Related Rebate	0.00
Effective Rate ($/ MWH)	39.63
Non-Smelter Member Blend	
Net Rate ($/ MWH)	38.88
MRDA	0.00
Regulatory Charge	(0.65)
FAC	15.35
Environmental Surcharge	2.84
Surcredit	(3.97)
PCA - Net	14.22
Economic Reserve	(9.22)
TIER Related Rebate	0.00
Effective Rate ($/ MWH)	43.23

Calendar Year	2012
Smelters	
Base Rate	31.21
TIER Adjusiment	1.58
Smelter Rate Subject to Price Cap	32.79
FAC, Non-FAC PPA, ES	16.90
Surcharge 1	0.67
Surcharge 2	1.20
TIER Related Rebate	0.00
Effective Rate	51.56
Market	57.59

III. Income Statement

Electric Energy Revenues	620.94
Income From Leased Property Net	0.00
Other Operating Revenue and Income	7.48
TOTAL OPER. REVENUES & PATRONAGE CAPITAL	628.42
Operating Expense-Production-Excluding Fuel	61.34
Operating Expense-Production-Fuel	220.99
Operating Expense-Other Power Supply	141.23
Operating Expense-Transmission	8.08
Operating Expense-Distribution	
Operating Expense-Customer Accounts	
Operating Expense-Customer Service and Information	0.76
Operating Expense-Sales	1.81
Operating Expense-Administrative and General	28.95
TOTAL OPERATION EXPENSE	463.17
Maintenance Expense-Production	59.17
Maintenance Expense-Transmission	4.53
Maintenance Expense-Distribution	
Maintenance Expense-General Plant	0.17
TOTAL MAINTENANCE EXPENSE	63.86
Depreciation and Amortization Expense	43.37
Taxes	0.00
Interest on Long-Term Debt	47.45
Interest Charged to Construction - Credit	(0.70)
Other Interest Expense	
Asset Retirement Obligation	
Other Deductions	0.14
TOTAL COST OF ELECTRIC SERVICE	617.29
OPERATING MARGINS	11.13
Interest Income	0.42
Allowance For Funds Used During Construction	
Income (Loss) From Equity Investments	
Other Non-Operating Income (Net)	
Generation and Transmission Capital Credits	
Other Capital Credits and Patronage Dividends	0.00
Extraordinary Items	
NET PATRONAGE CAPITAL OR MARGIN	11.55

IV. Balance Sheet

Total Utility Plant in Service	2,154.60
Construction Work in Progress	5.00
Total Utility Plant	2,159.60
Accum. Provision for Depreciation and Amort.	1,030.70
NET UTILITY PLANT	1,128.90

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Calendar Year	2012
Non-Utility Property (Net)	
Invest. In Assoc. Org - Patronage Capital	3.57
Invest. In Assoc. - Other - General Funds	0.68
Other Investments	0.02
Special Funds	0.78
Special Funds (Transition Reserve)	36.01
Special Funds (Economic Reserve)	63.94
Special Funds (Rural Economic Reserve)	64.40
TOTAL OTHER PROPERTY AND INVESTMENTS	169.40
Cash - General Funds	0.01
Cash - Construction Funds - Trustee	
Special Deposits	0.57
Temporary Investments	35.10
Accounts Receivable - Sales of Eergy (Net)	51.74
Accounts Receivable - Other (Net)	0.85
Fuel Stock	34.28
Materials and Supplies - Other	22.79
Prepayments	5.39
Other Current and Accrued Assets	2.24
TOTAL CURRENT AND ACCRUED ASSETS	152.97
Unamortized Debt Discount & Extraor. Prop. Losses	3.32
Regulatory Assets	0.00
Other Deferred Debits	1.41
Accumulated Deferred Income Taxes	0.00
TOTAL ASSETS AND OTHER DEBITS	1,456.01
TOTAL MARGINS & EQUITY	413.84
Long-Term Debt - RUS	622.03
Long-Term Debt - Other	227.10
TOTAL LONG-TERM DEBT	849.13
Notes Payable	
Accounts Payable	35.62
Accounts Payable (TIER Rebate)	0.00
Taxes Accrued	0.00
Interest Accrued	7.99
Other Current and Accrued Liabilities	3.89
Other Current and Accrued Liabilities (Purchased Power)	8.93
TOTAL CURRENT AND ACCRUED LIABILITIES	56.43
Deferred Credits	0.00
Deferred Credits (Economic Reserve)	63.94
Deferred Credits (Rural Economic Reserve)	64.40
Accumulated Operating Provisions	8.27
Obligation under Capital Leases - Noncurrent	
TOTAL LIABILITIES AND OTHER CREDITS	1,456.01

V. Cash Flow Statement

Operating Receipts	
Rural	111.31
Large Industrial	37.62
Smelters	377.27
Offsystem	62.94
Gain on Sale of Allowances	0.00
Cobank Patronage Capital & Other	0.02
Interest Earnings	0.42
Total Receipts	589.58

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Calendar Year	2012
Operating Disbursements	
PPA	
Fuel Costs	256.54
Fuel Costs (Labor & Exp)	5.31
Domtar	(0.02)
Power Supply (Purch. Power, APM, Cogen, & TVA Tran)	92.85
Production O&M	120.51
Transmission O&M	12.61
A&G	31.69
Working Capital	(1.51)
Debt Refunding Cost	1.49
Other	0.02
Total Disbursements	519.48
Operating Receipts less Disbursements	70.10
Capital Expenditures	
Generation	58.81
Transmission	6.26
A&G	0.61
Other (HQ Building, IP)	0.00
Total Capital Expenditures	65.68
Income Taxes from Operations	0.00
Net Pre-Finance Cash Flow	4.42
Financing	
Principal	(8.92)
Interest	39.97
Line of Credit	0.00
Aggregate Debt Service (Incl. Line of Credit)	31.05
Post-Finance Cash Flow	(26.63)
Unwind Transaction	
Cash Proceeds	
Debt Reduction	
Misc. Transaction	
Net Before Member Reserves	
Rural Economic Reserve	
Economic Reserve	31.78
Net Before Transition Reserve	31.78
Ending Cash Balances (Incl. Transition Reserve)	71.11
Change in Working Capital	
Other Property	0.00
Accounts Receivable	2.30
Materials, Supplies & Other	0.66
Prepayments	0.10
Other Current Assets	0.00
Accounts Payable	(4.28)
Taxes Accrued	0.06
Other Accruals	(0.35)
CoBank Patronage Capital	0.00
Total	(1.51)

VI. Credit Measures

Contract TIER	
Earnings	11.55
Plus: Interest Expense, Financing Fees, and Restucturing	46.75
Plus: Imputed Rate Increase in 2010	0.00
Less: Offset to Imputed Rate Increase in 2010	0.00

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Calendar Year	2012
Less: Interest on Sequestered Funds	(0.33)
Total	57.97
Plus Sale-Leaseback Interest	0.00
Total	57.97
Divided by	
Interest Expense, Financing Fees, and Restructuring	46.75
Plus Sale-Leaseback Interest	0.00
Total	46.75
Contract TIER	1.24
Conventional TIER	
Earnings	11.55
Plus: Interest Expense, Financing Fees, and Restucturing	46.75
Plus Income Tax	0.00
Total	58.30
Plus Sale-Leaseback Interest	0.00
Total	58.30
Divided by	
Interest Expense, Financing Fees, and Restructuring	46.75
Plus Sale-Leaseback Interest	0.00
Total	46.75
Conventional TIER	1.25

North Star	
Total Cost of Electric Service (millions of $)	617.29
Non-Member Revenues (millions of $)	70.84
	546.45
Smelter and Non-Smelter Member Sales (TWh)	10.76
$/MWh	50.78
$/kWh	0.050777

M. Hite

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

April 27, 2010

Mr. Jeff DeRouen
Executive Director
c/o Daryl Newby
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

file: PSC

RE: Big Rivers' Financial Model

Dear Mr. DeRouen:

As required by Item 15 of Appendix A of the Commission's Order of March 6, 2009, in Case No. 2007-00455, in the "Unwind Transaction", enclosed are five disk copies of Big Rivers' "Financial Model" in Excel format. The enclosed Financial Model contains the actual financial results for 2009, the revised 2010 budget, and the revised 2011-2013 financial plan. The Financial Model provides annual data for 2009, monthly data for January 2010 through December 2011, and annual data for 2012 and 2013. One hard copy print out of certain key elements of the Financial Model (the Excel file sheet titled "Stmts RUS") and a summary of certain Significant Facts and Assumptions are also enclosed.

In reviewing the actual financial results for 2009, please note that the "Unwind" closing occurred July 16, 2009. Should you have any questions regarding this information, please let us hear from you.

Sincerely,

BIG RIVERS ELECTRIC CORPORATION

Mark A. Hite

Mark A. Hite, CPA
Vice President Accounting

Enclosures
c: Mr. Mark A. Bailey (with enclosures)
Mr. C. William Blackburn (with enclosures)
Mr. Albert Yockey (with enclosures)
Mr. Kelly Nuckols, Jackson Purchase Energy Corporation (with enclosures)
Mr. Sandy Novick, Kenergy Corp. (with enclosures)
Mr. Burns Mercer, Meade County RECC (with enclosures)
James Miller, Esq., General Counsel (with enclosures)

Significant Facts and Assumptions for 2010 through 2013 Financial Forecast

- No SO2 or NOX allowance sales.
- Member Sales - demand and energy billing units for Rural and Large Industrial load per Load Forecast; Century @ 482 MW @ 98% load factor; Alcan @ 368 MW @ 98% load factor.
- Production Cost Model utilized for sources and uses of energy.
- Purchased Power: SEPA per agreement; market primarily on economic dispatch basis per Production Cost Model, ensuring system load requirements are met. Purchased Power is reflective of HMP&L Excess Energy Charge and the Non-Smelter Member Non-FAC Purchased Power Adjustment Regulatory Accounting.
- Includes a Depreciation Study reflective of that included in the October 2008 Unwind Model effective with the 2012 general rate adjustment.
- Regulatory Account for Non-Smelter Member Non-FAC Purchased Power Adjustment amortized over three-year period beginning 2012.

Date: 4/27/10

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Significant Facts and Assumptions for 2010 through 2013 Financial Forecast

- Interest income rate - 0.30% General Fund; 0.92% Transition Reserve; 1.49% Economic Reserve; 1.87% Rural Economic Reserve.
- Includes no automatic reserve sharing (ARS) solution.
- Base tariff rate increase of 11.75% in 2012.
- Refund $83.3 million PCBs in 2010 at 6.75%.
- Refund $58.8 million PCBs in 2013 at 6.75%.
- Lump sum RUS debt payment of $60 million due in 2012.
  - Borrow $85 million public debt in 2012 to fund the $60 million lump sum payment and $25 million to fund certain capital expenditures .
  - 8.75% rate for the public debt.

Date: 4/27/10

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Significant Facts and Assumptions for 2010 through 2013 Financial Forecast

- Non-Variable Operation & Maintenance Non-Labor cost escalated at 2.5%; Bargaining Labor escalated at 3.2% per contract; Non-Bargaining reflects no increase in 2010 and 3% 2011 through 2013; Labor Overheads escalated at 3% .
- Capital Expenditures: 2010 - $45.0 million; 2011 = $57.1 million; 2012 = $65.7 million; 2013 = $53.7 million.
- Year-end cash balance: 2010 = $44.8 million; 2011 = $22.5 million; 2012 = $32.1 million; 2013 = $23.6 million.

Date: 4/27/10

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Significant Facts and Assumptions for 2010 through 2013 Financial Forecast

- Production Work Plan Revisions required to meet budget constraints:
  - ✓ 2010 – Green 1 outage moved to 2011. Reduced scope of Wilson outage. Cancelled certain generation-related projects.
  - ✓ 2011 – Coleman 1, Green 2 and Wilson 1 outages moved to 2012. Added Combustion Turbine inspection.
  - ✓ 2012 – Green 1 outage moved to 2013.
- Station Two: City of Henderson's take is 100 MW for FYE 5/31/2010, increasing 5MW annually thereafter. Letter dated April 30, 2009, from HMP&L states its intent to reserve 120 MW (of the 312 MW total) by June 1, 2013.

Date: 4/27/10

Calendar Year	2009 Actual
I. Sales (TWH)	
Rural	2.24
Large Industrial	0.92
Century	1.47
Alcan	1.41
Market	1.75
Total Sales	7.79
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)	
General Rate Adjustment (%)	0.00%
Rural	
Load Factor (%)	60.83%
Demand ($/ KW-mo.)	7.37
Energy ($/ MWH)	20.40
Net Rate ($/ MWH)	37.00
MRDA	0.00
Regulatory Charge	0.00
FAC	4.41
Environmental Surcharge	1.04
Surcredit	(1.51)
Total	3.94
Economic Reserve	(3.94)
Rural Economic Reserve	0.00
TIER Related Rebate	0.00
Effective Rate ($/ MWH)	37.00
Large Industrial	
Load Factor (%)	74.36%
Demand ($/ KW-mo.)	10.15
Energy ($/ MWH)	13.72
Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.08
Net Rate ($/ MWH)	32.48
MRDA	0.00
Regulatory Charge	0.00
FAC	4.54
Environmental Surcharge	1.08
Surcredit	(1.57)
Total	4.05
Economic Reserve	(4.05)
TIER Related Rebate	0.00
Effective Rate ($/ MWH)	32.48

	Calendar Year	2009 Actual
54	**Non-Smelter Member Blend**	
55	Net Rate ($/ MWH)	35.68
56		
57	MRDA	0.00
58	Regulatory Charge	0.00
59	FAC	4.45
60	Environmental Surcharge	1.05
61	Surcredit	(1.53)
62	Total	3.97
63	Economic Reserve	(3.97)
64	Rural Economic Reserve	0.00
65	TIER Related Rebate	0.00
66	Effective Rate ($/ MWH)	35.68
67		
68	**Smelters**	
69	Base Rate ($/ MWH)	30.43
70	TIER Adjustment	1.95
71	Smelter Rate Subject to Price Cap	32.38
72	Non-FAC PPA	(0.56)
73	FAC	10.38
74	Environmental Surcharge	2.45
75	Surcharge 1	0.37
76	Surcharge 2	1.20
77	TIER Related Rebate	0.00
78	Effective Rate ($/ MWH)	46.22
79		
80	Market ($/ MWH)	38.66
81		
82	**III. Statement of Operations (millions of $)**	
83		
84	Electric Energy Revenues	326.73
85	Income From Leased Property Net	15.89
86	Other Operating Revenue and Income	14.60
87	**TOTAL OPER. REVENUES & PATRONAGE CAPITAL**	357.22
88		
89	Operating Expense-Production-Excluding Fuel	22.38
90	Operating Expense-Production-Fuel	80.65
91	Operating Expense-Other Power Supply	115.83
92	Operating Expense-Transmission	8.26
93	Operating Expense-Distribution	
94	Operating Expense-Customer Accounts	
95	Operating Expense-Customer Service and Information	0.72
96	Operating Expense-Sales	0.55
97	Operating Expense-Administrative and General	24.19
98	**TOTAL OPERATION EXPENSE**	252.58
99		
100	Maintenance Expense-Production	24.40
101	Maintenance Expense-Transmission	5.23
102	Maintenance Expense-Distribution	
103	Maintenance Expense-General Plant	0.17
104	**TOTAL MAINTENANCE EXPENSE**	29.80
105		
106	Depreciation and Amortization Expense	18.46
107	Taxes	1.83
108	Interest on Long-Term Debt	60.03
109	Interest Charged to Construction - Credit	(0.13)
110	Other Interest Expense	0.00

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	Calendar Year	2009 Actual
111	Asset Retirement Obligation	
112	Other Deductions	2.17
113		
114	**TOTAL COST OF ELECTRIC SERVICE**	364.74
115		
116	**OPERATING MARGINS**	(7.51)
117		
118	Interest Income	0.32
119	Allowance For Funds Used During Construction	
120	Income (Loss) From Equity Investments	
121	Other Non-Operating Income (Net)	0.01
122	Generation and Transmission Capital Credits	
123	Other Capital Credits and Patronage Dividends	0.54
124	Extraoridinary Items	537.98
125	**NET PATRONAGE CAPITAL OR MARGIN**	531.33
126		
127		
128	**IV. Balance Sheet (millions of $)**	
129	Total Utility Plant in Service	1,931.12
130	Construction Work in Progress	55.26
131	Total Utility Plant	1,986.37
132	Accum. Provision for Depreciation and Amort.	908.10
133	**NET UTILITY PLANT**	1,078.27
134		
135	Non-Utility Property (Net)	
136	Invest. In Assoc. Org - Patronage Capital	3.58
137	Invest. In Assoc. - Other - General Funds	0.68
138	Other Investments	0.02
139	Special Funds	0.65
140	Special Funds (Transition Reserve)	35.04
141	Special Funds (Economic Reserve)	147.61
142	Special Funds (Rural Economic Reserve)	60.58
143	**TOTAL OTHER PROPERTY AND INVESTMENTS**	248.16
144		
145	Cash - General Funds	0.24
146	Cash - Construction Funds - Trustee	
147	Special Deposits	0.57
148	Temporary Investments	59.89
149	Accounts Receivable - Sales of Eergy (Net)	39.90
150	Accounts Receivable - Other (Net)	5.28
151	Fuel Stock	37.83
152	Materials and Supplies - Other	20.41
153	Prepayments	5.01
154	Other Current and Accrued Assets	2.31
155	**TOTAL CURRENT AND ACCRUED ASSETS**	171.45
156		
157	Unamortized Debt Discount & Extraor. Prop. Losses	0.93
158	Regulatory Assets	0.00
159	Other Deferred Debits	6.67
160	Accumulated Deferred Income Taxes	0.00
161		
162	**TOTAL ASSETS AND OTHER DEBITS**	1,505.48
163		
164		

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	Calendar Year	2009 Actual
165	**TOTAL MARGINS & EQUITY**	379.39
166		
167	Long-Term Debt - RUS	706.45
168	Long-Term Debt - Other	142.10
169	**TOTAL LONG-TERM DEBT**	848.55
170		
171	Notes Payable	
172	Accounts Payable	34.02
173	Accounts Payable (TIER Rebate)	0.00
174	Taxes Accrued	0.45
175	Interest Accrued	9.10
176	Other Current and Accrued Liabilities	9.41
177	Other Current and Accrued Liabilities (Purchased Power)	
178	**TOTAL CURRENT AND ACCRUED LIABILITIES**	52.98
179		
180	Deferred Credits	1.17
181	Deferred Credits (Economic Reserve)	144.97
182	Deferred Credits (Rural Economic Reserve)	61.21
183	Accumulated Operating Provisions	17.21
184	Obligation under Capital Leases - Noncurrent	
185		
186	**TOTAL LIABILITIES AND OTHER CREDITS**	1,505.48
187		
188	Balance Check	(0.00)
189	**V. Cash Flow Statement (millions of $)**	
190	Operating Receipts	
191	Rural	83.29
192	Large Industrial	30.01
193	Smelters	133.38
194	Offsystem	67.52
195	Lease Income	23.21
196	Other Operating Revenues	14.60
197	Gain on Sale of Allowances	0.00
198	Other	0.36
199	Interest Earnings	0.32
200	Total Receipts	352.68
201		
202	Operating Disbursements	
203	PPA	51.59
204	Fuel Costs	77.82
205	Fuel Costs (Labor & Exp)	2.83
206	Domtar	0.00
207	Power Supply (Purch. Power, APM, Cogen, & TVA Tran)	62.22
208	Production O&M	46.78
209	Transmission O&M	13.48
210	A&G	25.47
211	Working Capital	0.40
212	Other	(1.86)
213	Total Disbursements	278.76
214		
215	Operating Receipts less Disbursements	73.92
216		
217	Capital Expenditures	

	Calendar Year	2009 Actual
218	Generation	45.73
219	Transmission	5.49
220	A&G	1.89
221	Other (HQ Building, IT)	5.27
222	**Total Capital Expenditures**	**58.39**
223		
224	Income Taxes from Operations	1.03
225		
226	Net Pre-Finance Cash Flow	14.51
227		
228	Financing	
229	Principal	41.14
230	Interest	53.76
231	Debt Issuance Cost Bond Refunding	0.25
232	Line of Credit	0.00
233	Aggregate Debt Service (incl. Line of Credit)	95.14
234		
235	Post-Finance Cash Flow	(80.63)
236		
237	Unwind Transaction	
238	Cash Proceeds	505.38
239	Debt Reduction	(140.20)
240	Misc. Transaction	(18.99)
241	Net Before Member Reserves	346.19
242	Station Two O&M Fund	(0.40)
243	Rural Economic Reserve	(60.86)
244	Economic Reserve	(147.81)
245	Net Before Transition Reserve	137.13
246		
247	**Ending Cash Balances (Incl. Transition Reserve)**	**95.17**
248	**Ending Cash Balances (Excl. Transition Reserve)**	**60.13**
249	Change in Working Capital	
250	Other Property	0.00
251	Accounts Receivable	26.05
252	Materials, Supplies & Other	3.50
253	Prepayments	2.78
254	Other Current Assets	1.54
255	Accounts Payable	(18.85)
256	Taxes Accrued	0.00
257	Other Accruals	(14.61)
258	Total	0.40
259		
260		

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	Calendar Year	2009 Actual
261	**VI. Credit Measures**	
262		
263	Contract TIER	
264	Earnings	(14.02)
265	Plus: Interest Expense	22.96
266	Plus: Imputed Rate Increase in 2010	0.00
267	Less: Offset to Imputed Rate Increase in 2010	0.00
268	Less: Interest on Sequestered Funds	(0.12)
269	Total	8.82
270	Plus Sale-Leaseback Interest	0.00
271	Total	8.82
272	Divided by	
273	Interest Expense	22.96
274	Plus Sale-Leaseback Interest	0.00
275	Total	22.96
276		
277	***Contract TIER***	0.38
278		
279	Conventional TIER	
280	Earnings	531.33
281	Plus: Interest Expense	60.03
282	Plus Income Tax	
283	Total	591.36
284	Plus Sale-Leaseback Interest	0.00
285	Total	591.36
286	Divided by	
287	Interest Expense	60.03
288	Plus Sale-Leaseback Interest	0.00
289	Total	60.03
290		
291	***Conventional TIER***	9.85
292		
293		
294		
295	North Star	
296	Total Cost of Electric Service (millions of $)	364.74
297	Non-Member Revenues (millions of $)	82.98
298		281.76
299		
300	Smelter and Non-Smelter Member Sales (TWh)	6.04
301	$/MWh	46.61
302	**$/kWh**	0.046614

Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
I. Sales (TWH)													
Rural	0.25	0.22	0.20	0.16	0.16	0.20	0.23	0.23	0.18	0.16	0.19	0.24	2.41
Large Industrial	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.07	0.08	0.96
Century	0.35	0.32	0.35	0.34	0.35	0.34	0.35	0.35	0.34	0.35	0.34	0.35	4.14
Alcan	0.27	0.24	0.27	0.26	0.27	0.26	0.27	0.27	0.26	0.27	0.26	0.27	3.16
Market	0.09	0.04	0.06	0.12	0.11	0.10	0.11	0.10	0.07	0.12	0.14	0.12	1.17
Total Sales	1.04	0.89	0.96	0.95	0.98	0.99	1.04	1.04	0.93	0.98	1.00	1.06	11.85
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise n													
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Rural													
Load Factor (%)	63.71%	65.66%	68.09%	62.86%	61.83%	61.19%	62.49%	62.36%	55.68%	64.25%	63.76%	68.00%	
Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	
Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	
Net Rate ($/ MWH)	36.25	35.78	35.23	36.46	36.73	36.90	36.56	36.59	38.53	36.11	36.23	35.25	36.34
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	10.14	9.89	9.71	10.25	10.40	10.95	11.17	11.17	10.95	11.08	10.94	10.97	10.64
Environmental Surcharge	2.68	2.77	2.85	2.25	2.31	2.41	2.39	2.39	2.48	2.31	2.39	2.33	2.47
Surcredit	(2.98)	(3.06)	(3.54)	(4.00)	(3.89)	(3.32)	(3.15)	(3.04)	(3.53)	(4.03)	(3.65)	(3.03)	(3.38)
Total	9.85	9.60	9.02	8.50	8.82	10.05	10.40	10.51	9.90	9.36	9.68	10.28	9.74
Economic Reserve	(9.85)	(9.60)	(9.02)	(8.50)	(8.82)	(10.05)	(8.40)	(8.51)	(7.90)	(7.36)	(7.68)	(8.28)	(8.72)
Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Effective Rate ($/ MWH)	36.25	35.78	35.23	36.46	36.73	36.90	38.56	38.59	40.53	38.11	38.23	37.25	37.36
Large Industrial													
Load Factor (%)	78.11%	74.67%	74.44%	78.35%	80.10%	79.31%	73.03%	83.04%	84.04%	79.59%	71.88%	75.93%	
Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	
Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	
Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net Rate ($/ MWH)	31.52	32.34	32.39	31.46	31.07	31.25	32.75	30.46	30.26	31.18	33.06	32.03	31.60
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FAC	10.14	9.89	9.71	10.25	10.40	10.95	11.17	11.17	10.95	11.08	10.94	10.97	10.65
Environmental Surcharge	2.68	2.77	2.85	2.25	2.31	2.41	2.39	2.39	2.48	2.31	2.39	2.33	2.46
Surcredit	(2.98)	(3.06)	(3.54)	(4.00)	(3.89)	(3.32)	(3.15)	(3.04)	(3.53)	(4.03)	(3.65)	(3.03)	(3.44)
Total	9.85	9.60	9.02	8.50	8.82	10.05	10.40	10.51	9.90	9.36	9.68	10.28	9.67
Economic Reserve	(9.85)	(9.60)	(9.02)	(8.50)	(8.82)	(10.05)	(8.40)	(8.51)	(7.90)	(7.36)	(7.68)	(8.28)	(8.66)
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Effective Rate ($/ MWH)	31.52	32.34	32.39	31.46	31.07	31.25	34.75	32.46	32.26	33.18	35.06	34.03	32.60

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	Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
54	**Non-Smelter Member Blend**													
55	Net Rate ($/ MWH)	35.08	34.89	34.44	34.78	34.81	35.27	35.62	34.89	35.78	34.44	35.34	34.47	34.99
56														
57	MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59	FAC	10.14	9.89	9.71	10.25	10.40	10.95	11.17	11.17	10.95	11.08	10.94	10.97	10.64
60	Environmental Surcharge	2.68	2.77	2.85	2.25	2.31	2.41	2.39	2.39	2.48	2.31	2.39	2.33	2.47
61	Surcredit	(2.98)	(3.06)	(3.54)	(4.00)	(3.89)	(3.32)	(3.15)	(3.04)	(3.53)	(4.03)	(3.65)	(3.03)	(3.40)
62	Total	9.85	9.60	9.02	8.50	8.82	10.05	10.40	10.51	9.90	9.36	9.68	10.28	9.72
63	Economic Reserve	(9.85)	(9.60)	(9.02)	(8.50)	(8.82)	(10.05)	(8.40)	(8.51)	(7.90)	(7.36)	(7.68)	(8.28)	(8.70)
64	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Effective Rate ($/ MWH)	35.08	34.89	34.44	34.78	34.81	35.27	37.62	36.89	37.78	36.44	37.34	36.47	36.01
67														
68	**Smelters**													
69	Base Rate ($/ MWH)	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15
70	TIER Adjustment	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95
71	Smelter Rate Subject to Price Cap	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10
72	Non-FAC PPA	(1.20)	(1.03)	(1.32)	(1.75)	(1.75)	(1.71)	(1.65)	(1.51)	(1.47)	(1.69)	(1.57)	(1.60)	(1.52)
73	FAC	10.14	9.89	9.71	10.25	10.40	10.95	11.17	11.17	10.95	11.08	10.94	10.97	10.64
74	Environmental Surcharge	2.68	2.77	2.85	2.25	2.31	2.41	2.39	2.39	2.48	2.31	2.39	2.33	2.46
75	Surcharge 1	0.36	0.40	0.36	0.38	0.36	0.38	0.36	0.36	0.38	0.36	0.38	0.36	0.37
76	Surcharge 2	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
77	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
78	Effective Rate ($/ MWH)	43.29	43.34	42.90	42.43	42.63	43.34	43.58	43.72	43.64	43.37	43.44	43.37	43.25
79														
80	Market ($/ MWH)	45.78	57.29	55.00	40.82	46.39	52.83	45.21	44.24	49.14	50.87	44.62	41.88	46.82
81														
82	**III. Statement of Operations (millions of $)**													
83														
84	Electric Energy Revenues	45.63	40.69	42.02	40.44	42.56	44.37	46.08	45.88	41.64	43.40	43.82	46.25	522.78
85	Income From Leased Property Net	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
86	Other Operating Revenue and Income	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	7.48
87	**TOTAL OPER. REVENUES & PATRONAGE CAPITAL**	46.25	41.31	42.65	41.06	43.18	44.99	46.71	46.51	42.27	44.03	44.44	46.87	530.27
88														
89	Operating Expense-Production-Excluding Fuel	4.75	4.39	4.92	4.39	4.68	4.74	4.61	4.44	4.59	4.23	4.38	4.46	54.59
90	Operating Expense-Production-Fuel	15.98	13.30	14.53	16.85	15.99	17.13	18.17	18.24	15.45	16.05	16.90	17.66	196.26
91	Operating Expense-Other Power Supply	9.60	9.03	9.83	8.32	8.43	8.59	8.59	8.48	8.70	9.00	8.29	8.91	105.76
92	Operating Expense-Transmission	0.70	0.63	0.68	0.61	0.61	0.67	0.67	0.62	0.83	0.61	0.61	0.66	7.91
93	Operating Expense-Distribution													
94	Operating Expense-Customer Accounts													
95	Operating Expense-Customer Service and Information	0.07	0.05	0.06	0.06	0.06	0.07	0.06	0.06	0.07	0.06	0.06	0.07	0.73
96	Operating Expense-Sales	0.03	0.02	0.03	0.02	0.02	0.03	0.02	0.02	0.22	0.04	0.05	0.13	0.61
97	Operating Expense-Administrative and General	2.87	2.45	2.75	2.48	2.28	2.94	2.61	2.30	2.53	2.25	1.94	2.23	29.63
98	**TOTAL OPERATION EXPENSE**	34.01	29.88	32.80	32.73	32.07	34.17	34.73	34.15	32.38	32.24	32.24	34.11	395.50
99														
100	Maintenance Expense-Production	2.32	3.08	3.12	3.60	4.16	3.23	3.08	2.95	6.45	3.25	2.82	2.73	40.79
101	Maintenance Expense-Transmission	0.35	0.33	0.41	0.35	0.34	0.45	0.44	0.42	0.46	0.32	0.33	0.37	4.58
102	Maintenance Expense-Distribution													
103	Maintenance Expense-General Plant	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.06
104	**TOTAL MAINTENANCE EXPENSE**	2.68	3.41	3.53	3.96	4.50	3.69	3.54	3.38	6.92	3.58	3.15	3.10	45.42
105														
106	Depreciation and Amortization Expense	2.88	2.88	2.88	2.88	2.89	2.89	2.90	2.90	2.91	2.92	2.94	2.95	34.83
107	Taxes	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
108	Interest on Long-Term Debt	4.13	3.73	4.13	3.93	4.01	3.88	4.01	4.06	3.92	4.06	3.97	4.23	48.08
109	Interest Charged to Construction - Credit	(0.02)	(0.03)	(0.04)	(0.04)	(0.05)	(0.06)	(0.06)	(0.07)	(0.06)	(0.05)	(0.05)	(0.05)	(0.58)
110	Other Interest Expense													

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	Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
111	Asset Retirement Obligation	0.00	0.00	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.10
112	Other Deductions													
113														
114	TOTAL COST OF ELECTRIC SERVICE	43.70	39.90	43.34	43.50	43.43	44.59	45.15	44.45	46.12	42.77	42.28	44.38	523.61
115														
116	OPERATING MARGINS	2.55	1.41	(0.69)	(2.44)	(0.26)	0.40	1.56	2.06	(3.85)	1.26	2.16	2.50	6.66
117														
118	Interest Income	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.45
119	Allowance For Funds Used During Construction													
120	Income (Loss) From Equity Investments													
121	Other Non-Operating Income (Net)													
122	Generation and Transmission Capital Credits													
123	Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
124	Extraoridinary Items													
125	NET PATRONAGE CAPITAL OR MARGIN	2.59	1.44	(0.65)	(2.40)	(0.22)	0.44	1.59	2.10	(3.81)	1.30	2.20	2.54	7.11
126														
127														
128	IV. Balance Sheet (millions of $)													
129	Total Utility Plant in Service	1,937.25	1,943.49	1,950.99	1,959.94	1,967.00	1,975.07	1,983.11	1,990.65	2,000.76	2,005.35	2,006.54	2,006.98	
130	Construction Work in Progress	52.00	49.00	46.00	43.00	40.00	37.00	34.00	31.00	28.00	25.00	25.00	25.00	
131	Total Utility Plant	1,989.25	1,992.49	1,996.99	2,002.94	2,007.00	2,012.07	2,017.11	2,021.65	2,028.76	2,030.35	2,031.54	2,031.98	
132	Accum. Provision for Depreciation and Amort.	911.13	914.16	917.20	920.24	923.28	926.32	929.38	932.43	935.51	938.58	941.68	944.79	
133	NET UTILITY PLANT	1,078.12	1,078.33	1,079.79	1,082.70	1,083.72	1,085.75	1,087.73	1,089.22	1,093.26	1,091.77	1,089.86	1,087.19	
134														
135	Non-Utility Property (Net)													
136	Invest. In Assoc. Org - Patronage Capital	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	
137	Invest. In Assoc. - Other - General Funds	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	
138	Other Investments	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	
139	Special Funds	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	
140	Special Funds (Transition Reserve)	35.06	35.09	35.11	35.14	35.17	35.20	35.22	35.25	35.28	35.30	35.33	35.36	
141	Special Funds (Economic Reserve)	144.59	141.94	139.66	137.82	135.80	133.10	130.68	128.14	126.18	124.57	122.73	120.24	
142	Special Funds (Rural Economic Reserve)	60.67	60.76	60.86	60.95	61.05	61.14	61.24	61.34	61.43	61.53	61.62	61.72	
143	TOTAL OTHER PROPERTY AND INVESTMENTS	245.26	242.72	240.56	238.84	236.94	234.37	232.08	229.65	227.82	226.33	224.62	222.25	
144														
145	Cash - General Funds	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	
146	Cash - Construction Funds - Trustee													
147	Special Deposits	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	
148	Temporary Investments	24.25	32.96	36.65	23.06	22.97	24.16	25.99	28.77	32.77	34.06	40.54	44.53	
149	Accounts Receivable - Sales of Eergy (Net)	45.63	40.69	42.02	40.44	42.56	44.37	46.08	45.88	41.64	43.40	43.82	46.25	
150	Accounts Receivable - Other (Net)	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	
151	Fuel Stock	37.56	37.22	36.93	37.51	38.11	38.48	38.76	38.64	38.32	38.55	38.51	38.53	
152	Materials and Supplies - Other	20.46	20.51	20.57	20.62	20.67	20.72	20.77	20.82	20.88	20.93	20.98	21.03	
153	Prepayments	4.42	3.86	3.27	2.85	2.57	2.30	2.03	1.75	1.48	1.21	0.93	3.73	
154	Other Current and Accrued Assets	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	
155	TOTAL CURRENT AND ACCRUED ASSETS	140.73	143.65	147.85	132.88	135.29	138.44	142.04	144.29	143.49	146.55	153.19	162.48	
156														
157	Unamortized Debt Discount & Extraor. Prop. Losses	0.92	0.92	0.91	2.36	2.35	2.34	2.34	2.33	2.32	2.31	2.30	2.29	
158	Regulatory Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
159	Other Deferred Debits	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	
160	Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
161														
162	TOTAL ASSETS AND OTHER DEBITS	1,471.70	1,472.29	1,475.79	1,463.46	1,464.98	1,467.57	1,470.85	1,472.15	1,473.56	1,473.63	1,476.64	1,480.89	
163														
164														

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	Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
165	TOTAL MARGINS & EQUITY	381.98	383.42	382.77	380.37	380.15	380.59	382.18	384.28	380.47	381.76	383.96	386.50	
166														
167	Long-Term Debt - RUS	679.52	679.52	681.08	677.14	677.14	678.75	687.06	687.06	688.71	697.15	697.15	698.82	
168	Long-Term Debt - Other	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	
169	TOTAL LONG-TERM DEBT	821.62	821.62	823.18	819.24	819.24	820.85	829.16	829.16	830.81	839.25	839.25	840.92	
170														
171	Notes Payable													
172	Accounts Payable	30.20	28.24	30.53	30.56	30.12	30.88	30.70	29.92	33.05	29.20	28.37	28.75	
173	Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
174	Taxes Accrued	0.74	1.02	1.31	1.53	1.81	2.03	2.32	0.83	1.05	1.33	0.92	0.52	
175	Interest Accrued	3.68	6.71	8.51	3.56	6.90	8.54	3.58	6.98	8.62	3.59	6.93	8.83	
176	Other Current and Accrued Liabilities	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	
177	Other Current and Accrued Liabilities (Purchased Power)													
178	TOTAL CURRENT AND ACCRUED LIABILITIES	44.03	45.38	49.75	45.05	48.24	50.86	46.00	47.13	52.13	43.53	45.63	47.50	
179														
180	Deferred Credits	1.56	1.87	2.23	2.64	3.08	3.56	4.07	4.55	4.94	5.35	5.76	6.27	
181	Deferred Credits (Economic Reserve)	144.59	141.94	139.66	137.82	135.80	133.10	130.68	128.14	126.18	124.57	122.73	120.24	
182	Deferred Credits (Rural Economic Reserve)	60.67	60.76	60.86	60.95	61.05	61.14	61.24	61.34	61.43	61.53	61.62	61.72	
183	Accumulated Operating Provisions	17.25	17.30	17.34	17.38	17.43	17.47	17.52	17.56	17.60	17.65	17.69	17.74	
184	Obligation under Capital Leases - Noncurrent													
185														
186	TOTAL LIABILITIES AND OTHER CREDITS	1,471.70	1,472.29	1,475.79	1,463.46	1,464.98	1,467.57	1,470.85	1,472.15	1,473.56	1,473.63	1,476.64	1,480.89	
187														
188	Balance Check	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	
189	V. Cash Flow Statement (millions of $)													
190	Operating Receipts													
191	Rural	8.90	7.79	6.98	5.72	6.05	7.49	8.95	8.88	7.24	6.05	7.11	9.05	90.21
192	Large Industrial	2.53	2.43	2.45	2.50	2.63	2.57	2.62	2.87	2.87	2.72	2.56	2.63	31.36
193	Smelters	26.83	24.26	26.59	25.45	26.42	25.99	27.01	27.09	26.18	26.88	26.05	26.88	315.62
194	Offsystem	4.16	3.40	3.53	4.76	5.27	5.45	4.92	4.33	3.24	5.99	6.11	5.04	56.20
195	Lease Income													
196	Other Operating Revenues													
197	Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
198	Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
199	Interest Earnings	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.45
200	Total Receipts	42.46	37.91	39.59	38.47	40.40	41.54	43.54	43.21	39.57	41.67	41.87	43.64	493.86
201														
202	Operating Disbursements													
203	PPA													
204	Fuel Costs	18.32	15.38	17.00	18.46	19.12	20.02	21.07	20.74	17.90	19.10	19.63	20.67	227.41
205	Fuel Costs (Labor & Exp)	0.39	0.38	0.43	0.41	0.43	0.45	0.48	0.47	0.42	0.42	0.41	0.40	5.09
206	Domtar	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)
207	Power Supply (Purch. Power, APM, Cogen, & TVA Tran)	5.43	5.15	5.50	5.70	4.26	4.36	4.22	4.13	4.33	4.58	3.93	4.22	55.81
208	Production O&M	7.07	7.47	8.04	7.99	8.84	7.97	7.70	7.39	11.04	7.49	7.20	7.18	95.38
209	Transmission O&M	1.05	0.96	1.08	0.96	0.95	1.12	1.11	1.04	1.29	0.93	0.94	1.04	12.48
210	A&G	2.98	2.53	2.84	2.55	2.36	3.05	2.70	2.38	2.82	2.34	2.06	2.42	31.03
211	Working Capital	7.00	(3.51)	(1.48)	(2.08)	2.03	0.58	1.36	1.82	(7.84)	5.08	1.41	5.29	9.64
212	Other	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
213	Total Disbursements	42.25	28.36	33.42	34.01	37.98	37.54	38.63	37.97	29.96	39.93	35.56	41.23	436.85
214														
215	Operating Receipts less Disbursements	0.21	9.55	6.18	4.45	2.41	4.00	4.90	5.24	9.60	1.74	6.31	2.41	57.01
216														
217	Capital Expenditures													

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Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
Generation	0.24	0.40	1.11	3.20	1.30	2.45	2.87	3.10	6.25	0.99	0.70	0.00	22.60
Transmission	1.21	1.59	1.91	1.96	1.87	1.81	1.41	1.30	0.76	0.49	0.42	0.36	15.09
A&G	0.28	0.10	0.31	0.13	0.22	0.06	0.04	0.04	0.04	0.06	0.02	0.04	1.32
Other (HQ Building, IT)	1.12	1.13	1.13	0.62	0.62	0.70	0.65	0.04	0.00	0.00	0.00	0.00	6.02
Total Capital Expenditures	**2.85**	**3.21**	**4.46**	**5.90**	**4.01**	**5.01**	**4.97**	**4.47**	**7.06**	**1.53**	**1.15**	**0.39**	**45.03**
Income Taxes from Operations	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
Net Pre-Finance Cash Flow	(2.66)	6.32	1.69	(1.47)	(1.62)	(1.03)	(0.09)	0.74	2.53	0.19	5.14	2.00	11.73
Financing													
Principal	26.94	0.00	0.00	3.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.87
Interest	9.22	0.40	0.44	8.71	0.64	0.62	0.64	0.64	0.62	0.64	0.62	0.64	23.82
Debt Issuance Cost Bond Refunding	0.00	0.00	0.00	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.45
Line of Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aggregate Debt Service (incl. Line of Credit)	36.16	0.40	0.44	14.10	0.64	0.62	0.64	0.64	0.62	0.64	0.62	0.64	56.15
Post-Finance Cash Flow	(38.82)	5.92	1.25	(15.57)	(2.26)	(1.65)	(0.73)	0.10	1.91	(0.45)	4.52	1.36	(44.41)
Unwind Transaction													
Cash Proceeds													
Debt Reduction													
Misc. Transaction													
Net Before Member Reserves													
Station Two O&M Fund													
Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Economic Reserve	3.21	2.81	2.47	2.01	2.20	2.87	2.58	2.71	2.11	1.77	1.99	2.65	29.38
Net Before Transition Reserve	3.21	2.81	2.47	2.01	2.20	2.87	2.58	2.71	2.11	1.77	1.99	2.65	29.38
Ending Cash Balances (Incl. Transition Reserve)	**59.55**	**68.29**	**72.01**	**58.44**	**58.38**	**59.60**	**61.45**	**64.27**	**68.29**	**69.61**	**76.12**	**80.13**	
Ending Cash Balances (Excl. Transition Reserve)	**24.49**	**33.20**	**36.89**	**23.30**	**23.22**	**24.40**	**26.23**	**29.02**	**33.01**	**34.30**	**40.79**	**44.77**	
Change in Working Capital													
Other Property	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accounts Receivable	5.73	(4.94)	1.34	(1.58)	2.12	1.82	1.71	(0.20)	(4.24)	1.76	0.42	2.43	6.35
Materials, Supplies & Other	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.62
Prepayments	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	2.82	0.00
Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accounts Payable	3.82	1.96	(2.29)	(0.03)	0.44	(0.76)	0.18	0.78	(3.13)	3.85	0.83	(0.38)	5.27
Taxes Accrued	(0.28)	(0.28)	(0.28)	(0.22)	(0.28)	(0.22)	(0.28)	1.49	(0.22)	(0.28)	0.41	0.41	(0.06)
Other Accruals	(2.06)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(2.54)
Total	7.00	(3.51)	(1.48)	(2.08)	2.03	0.58	1.36	1.82	(7.84)	5.08	1.41	5.29	9.64

	Calendar Year	2010 January	2010 February	2010 March	2010 April	2010 May	2010 June	2010 July	2010 August	2010 September	2010 October	2010 November	2010 December	2010 Total
261	VI. Credit Measures													
262														
263	Contract TIER													
264	Earnings	2.59	1.44	(0.65)	(2.40)	(0.22)	0.44	1.59	2.10	(3.81)	1.30	2.20	2.54	7.11
265	Plus: Interest Expense	4.13	3.73	4.13	3.93	4.01	3.88	4.01	4.06	3.92	4.06	3.97	4.23	48.08
266	Plus: Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
267	Less: Offset to Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
268	Less: Interest on Sequestered Funds	(0.03)	(0.02)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.32)
269	Total	6.69	5.15	3.46	1.50	3.76	4.29	5.58	6.12	0.09	5.33	6.15	6.74	54.86
270	Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
271	Total	6.69	5.15	3.46	1.50	3.76	4.29	5.58	6.12	0.09	5.33	6.15	6.74	54.86
272	Divided by													
273	Interest Expense	4.13	3.73	4.13	3.93	4.01	3.88	4.01	4.06	3.92	4.06	3.97	4.23	48.08
274	Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
275	Total	4.13	3.73	4.13	3.93	4.01	3.88	4.01	4.06	3.92	4.06	3.97	4.23	48.08
276														
277	*Contract TIER*	**1.62**	**1.38**	**0.84**	**0.38**	**0.94**	**1.11**	**1.39**	**1.51**	**0.02**	**1.31**	**1.55**	**1.59**	**1.14**
278														
279	Conventional TIER													
280	Earnings	2.59	1.44	(0.65)	(2.40)	(0.22)	0.44	1.59	2.10	(3.81)	1.30	2.20	2.54	7.11
281	Plus: Interest Expense	4.13	3.73	4.13	3.93	4.01	3.88	4.01	4.06	3.92	4.06	3.97	4.23	48.08
282	Plus Income Tax													
283	Total	6.72	5.18	3.49	1.53	3.79	4.31	5.61	6.15	0.11	5.36	6.17	6.77	55.19
284	Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
285	Total	6.72	5.18	3.49	1.53	3.79	4.31	5.61	6.15	0.11	5.36	6.17	6.77	55.19
286	Divided by													
287	Interest Expense	4.13	3.73	4.13	3.93	4.01	3.88	4.01	4.06	3.92	4.06	3.97	4.23	48.08
288	Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
289	Total	4.13	3.73	4.13	3.93	4.01	3.88	4.01	4.06	3.92	4.06	3.97	4.23	48.08
290														
291	*Conventional TIER*	**1.63**	**1.39**	**0.84**	**0.39**	**0.95**	**1.11**	**1.40**	**1.52**	**0.03**	**1.32**	**1.55**	**1.60**	**1.15**
292														
293														
294														
295	North Star													
296	Total Cost of Electric Service (millions of $)	43.70	39.90	43.34	43.50	43.43	44.59	45.15	44.45	46.12	42.77	42.28	44.38	523.61
297	Non-Member Revenues (millions of $)	4.82	2.82	4.20	5.42	5.93	6.11	5.58	4.99	3.90	6.65	6.77	5.71	62.90
298		38.88	37.09	39.14	38.08	37.51	38.48	39.57	39.46	42.21	36.12	35.51	38.67	460.71
299														
300	Smelter and Non-Smelter Member Sales (TWh)	0.95	0.85	0.89	0.84	0.87	0.88	0.93	0.94	0.87	0.86	0.86	0.94	10.67
301	$/MWh	41.12	43.50	43.80	45.55	43.17	43.48	42.67	42.06	48.67	41.98	41.35	41.14	43.16
302	$/kWh	0.041122	0.043496	0.043799	0.045547	0.043167	0.043485	0.042672	0.042056	0.048669	0.041983	0.041353	0.041142	0.043165

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Calendar Year	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
I. Sales (TWH)													
Rural	0.26	0.20	0.20	0.17	0.17	0.21	0.23	0.24	0.20	0.16	0.19	0.25	2.49
Large Industrial	0.08	0.09	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.95
Century	0.35	0.32	0.35	0.34	0.35	0.34	0.35	0.35	0.34	0.35	0.34	0.35	4.13
Alcan	0.27	0.24	0.27	0.26	0.27	0.26	0.27	0.27	0.26	0.27	0.26	0.27	3.16
Market	0.10	0.08	0.07	0.10	0.06	0.07	0.14	0.15	0.16	0.21	0.21	0.10	1.43
Total Sales	1.05	0.94	0.96	0.94	0.93	0.96	1.07	1.10	1.02	1.07	1.07	1.04	12.16
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise n													
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Rural													
Load Factor (%)	64.22%	65.73%	66.71%	64.17%	62.62%	61.95%	60.94%	64.09%	58.63%	64.32%	63.07%	68.21%	
Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	
Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	
Net Rate ($/ MWH)	36.12	35.76	35.53	36.13	36.52	36.70	36.97	36.15	37.62	36.10	36.41	35.20	36.25
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FAC	10.95	11.27	11.62	11.28	11.14	11.74	11.39	11.73	11.58	11.67	11.73	11.72	11.48
Environmental Surcharge	3.20	3.20	3.18	3.09	2.80	2.63	3.16	3.13	3.23	3.15	3.16	3.35	3.11
Surcredit	(2.92)	(3.01)	(3.47)	(3.92)	(3.81)	(3.26)	(3.09)	(2.99)	(3.48)	(3.96)	(3.58)	(2.97)	(3.32)
Total	11.23	11.46	11.33	10.44	10.13	11.11	11.45	11.87	11.34	10.85	11.31	12.10	11.28
Economic Reserve	(9.23)	(9.46)	(9.33)	(8.44)	(8.13)	(9.11)	(7.45)	(7.87)	(7.34)	(6.85)	(7.31)	(8.10)	(8.25)
Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Effective Rate ($/ MWH)	38.12	37.76	37.53	38.13	38.52	38.70	40.97	40.15	41.62	40.10	40.41	39.20	39.27
Large Industrial													
Load Factor (%)	76.12%	74.47%	78.57%	75.32%	78.60%	77.19%	78.94%	80.07%	76.99%	79.87%	74.00%	75.14%	
Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	
Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	
Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Net Rate ($/ MWH)	31.98	32.39	31.41	32.18	31.41	31.73	31.33	31.08	31.77	31.12	32.50	32.22	31.76
MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FAC	10.95	11.27	11.62	11.28	11.14	11.74	11.39	11.73	11.58	11.67	11.73	11.72	11.48
Environmental Surcharge	3.20	3.20	3.18	3.09	2.80	2.63	3.16	3.13	3.23	3.15	3.16	3.35	3.11
Surcredit	(2.92)	(3.01)	(3.47)	(3.92)	(3.81)	(3.26)	(3.09)	(2.99)	(3.48)	(3.96)	(3.58)	(2.97)	(3.37)
Total	11.23	11.46	11.33	10.44	10.13	11.11	11.45	11.87	11.34	10.85	11.31	12.10	11.22
Economic Reserve	(9.23)	(9.46)	(9.33)	(8.44)	(8.13)	(9.11)	(7.45)	(7.87)	(7.34)	(6.85)	(7.31)	(8.10)	(8.23)
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Effective Rate ($/ MWH)	33.98	34.39	33.41	34.18	33.41	33.73	35.33	35.08	35.77	35.12	36.50	36.22	34.75

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54	**Non-Smelter Member Blend**													
55	Net Rate ($/ MWH)	35.18	34.69	34.40	34.90	34.89	35.35	35.54	34.86	35.97	34.46	35.29	34.51	35.01
56														
57	MRDA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Regulatory Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59	FAC	10.95	11.27	11.62	11.28	11.14	11.74	11.39	11.73	11.58	11.67	11.73	11.72	11.48
60	Environmental Surcharge	3.20	3.20	3.18	3.09	2.80	2.63	3.16	3.13	3.23	3.15	3.16	3.35	3.11
61	Surcredit	(2.92)	(3.01)	(3.47)	(3.92)	(3.81)	(3.26)	(3.09)	(2.99)	(3.48)	(3.96)	(3.58)	(2.97)	(3.33)
62	Total	11.23	11.46	11.33	10.44	10.13	11.11	11.45	11.87	11.34	10.85	11.31	12.10	11.26
63	Economic Reserve	(9.23)	(9.46)	(9.33)	(8.44)	(8.13)	(9.11)	(7.45)	(7.87)	(7.34)	(6.85)	(7.31)	(8.10)	(8.25)
64	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Effective Rate ($/ MWH)	37.18	36.69	36.40	36.90	36.89	37.35	39.54	38.86	39.97	38.46	39.29	38.51	38.02
67														
68	**Smelters**													
69	Base Rate ($/ MWH)	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15	28.15
70	TIER Adjustment	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95
71	Smelter Rate Subject to Price Cap	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10	30.10
72	Non-FAC PPA	(1.62)	(1.61)	(1.21)	(1.75)	(1.75)	(1.39)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.65)
73	FAC	10.95	11.27	11.62	11.28	11.14	11.74	11.39	11.73	11.58	11.67	11.73	11.72	11.49
74	Environmental Surcharge	3.20	3.20	3.18	3.09	2.80	2.63	3.16	3.13	3.23	3.15	3.16	3.35	3.11
75	Surcharge 1	0.36	0.40	0.36	0.38	0.36	0.38	0.36	0.36	0.38	0.36	0.38	0.36	0.37
76	Surcharge 2	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
77	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
78	Effective Rate ($/ MWH)	44.20	44.57	45.26	44.30	43.86	44.66	44.47	44.78	44.75	44.73	44.82	44.98	44.61
79														
80	Market ($/ MWH)	46.30	46.92	47.13	46.80	45.21	49.35	53.15	55.06	45.15	43.75	43.66	45.59	47.17
81														
82	**III. Statement of Operations (millions of $)**													
83														
84	Electric Energy Revenues	47.33	42.64	43.85	42.21	41.13	43.57	49.47	51.32	46.59	47.94	48.29	47.53	551.87
85	Income From Leased Property Net	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
86	Other Operating Revenue and Income	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	7.48
87	TOTAL OPER. REVENUES & PATRONAGE CAPITAL	47.96	43.27	44.48	42.83	41.75	44.19	50.09	51.95	47.21	48.57	48.91	48.15	559.35
88														
89	Operating Expense-Production-Excluding Fuel	5.03	4.65	4.95	5.23	4.87	4.54	5.24	5.12	5.19	5.00	5.29	5.19	60.28
90	Operating Expense-Production-Fuel	18.92	17.27	16.77	16.11	17.24	18.11	19.85	20.35	18.65	20.40	19.73	19.39	222.77
91	Operating Expense-Other Power Supply	7.76	7.20	9.68	10.39	8.48	7.59	7.86	8.57	8.29	7.66	8.29	7.89	99.64
92	Operating Expense-Transmission	0.70	0.66	0.70	0.64	0.63	0.68	0.70	0.70	0.82	0.64	0.68	0.63	8.17
93	Operating Expense-Distribution													
94	Operating Expense-Customer Accounts													
95	Operating Expense-Customer Service and Information	0.07	0.07	0.07	0.06	0.06	0.07	0.06	0.08	0.06	0.06	0.07	0.06	0.77
96	Operating Expense-Sales	0.14	0.13	0.14	0.13	0.13	0.14	0.13	0.13	0.34	0.14	0.13	0.13	1.80
97	Operating Expense-Administrative and General	2.52	2.15	2.59	2.31	2.23	2.93	2.58	2.29	2.37	1.98	2.17	2.21	28.30
98	TOTAL OPERATION EXPENSE	35.13	32.12	34.89	34.86	33.64	34.06	36.40	37.22	35.71	35.88	36.35	35.50	421.74
99														
100	Maintenance Expense-Production	2.61	3.65	5.26	6.51	6.25	2.93	3.10	2.95	3.03	3.43	2.94	2.51	45.17
101	Maintenance Expense-Transmission	0.35	0.35	0.44	0.34	0.34	0.46	0.48	0.50	0.44	0.34	0.38	0.32	4.73
102	Maintenance Expense-Distribution													
103	Maintenance Expense-General Plant	0.02	0.02	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.17
104	TOTAL MAINTENANCE EXPENSE	2.98	4.01	5.70	6.87	6.59	3.40	3.60	3.47	3.48	3.78	3.34	2.85	50.07
105														
106	Depreciation and Amortization Expense	2.96	2.97	2.97	2.98	2.99	3.00	3.03	3.03	3.04	3.05	3.05	3.05	36.09
107	Taxes	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
108	Interest on Long-Term Debt	4.10	3.70	4.10	3.95	4.08	3.95	4.07	4.07	3.94	4.07	3.93	4.11	48.08
109	Interest Charged to Construction - Credit	(0.05)	(0.07)	(0.08)	(0.10)	(0.12)	(0.14)	(0.15)	(0.16)	(0.13)	(0.12)	(0.11)	(0.11)	(1.32)
110	Other Interest Expense													

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	Calendar Year	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
111	Asset Retirement Obligation													
112	Other Deductions	0.01	0.01	0.01	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.12
113														
114	TOTAL COST OF ELECTRIC SERVICE	45.15	42.76	47.60	48.60	47.22	44.30	46.99	47.66	46.07	46.68	46.59	45.43	555.04
115														
116	OPERATING MARGINS	2.81	0.51	(3.13)	(5.77)	(5.46)	(0.11)	3.10	4.28	1.15	1.88	2.32	2.72	4.32
117														
118	Interest Income	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.43
119	Allowance For Funds Used During Construction													
120	Income (Loss) From Equity Investments													
121	Other Non-Operating Income (Net)													
122	Generation and Transmission Capital Credits													
123	Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
124	Extraoridinary Items													
125	NET PATRONAGE CAPITAL OR MARGIN	2.85	0.55	(3.08)	(5.73)	(5.43)	(0.07)	3.13	4.32	1.18	1.92	2.36	2.76	4.74
126														
127														
128	IV. Balance Sheet (millions of $)													
129	Total Utility Plant in Service	2,012.28	2,016.27	2,019.70	2,030.13	2,040.06	2,045.97	2,049.75	2,054.38	2,062.76	2,063.99	2,064.85	2,065.42	
130	Construction Work in Progress	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	
131	Total Utility Plant	2,037.28	2,041.27	2,044.70	2,055.13	2,065.06	2,070.97	2,074.75	2,079.38	2,087.76	2,088.99	2,089.85	2,090.42	
132	Accum. Provision for Depreciation and Amort.	947.90	951.03	954.15	957.29	960.44	963.60	966.79	969.98	973.18	976.40	979.61	982.83	
133	NET UTILITY PLANT	1,089.38	1,090.25	1,090.55	1,097.85	1,104.63	1,107.37	1,107.97	1,109.39	1,114.57	1,112.59	1,110.23	1,107.59	
134														
135	Non-Utility Property (Net)													
136	Invest. In Assoc. Org - Patronage Capital	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	
137	Invest. In Assoc. - Other - General Funds	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	
138	Other Investments	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	
139	Special Funds	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	
140	Special Funds (Transition Reserve)	35.39	35.41	35.44	35.47	35.49	35.52	35.55	35.58	35.60	35.63	35.66	35.69	
141	Special Funds (Economic Reserve)	117.33	114.64	112.19	110.29	108.37	105.86	103.66	101.24	99.37	97.82	96.01	93.49	
142	Special Funds (Rural Economic Reserve)	61.82	61.91	62.01	62.10	62.20	62.29	62.39	62.49	62.59	62.69	62.78	62.88	
143	TOTAL OTHER PROPERTY AND INVESTMENTS	219.46	216.89	214.56	212.79	210.99	208.60	206.53	204.24	202.49	201.07	199.38	196.99	
144														
145	Cash - General Funds	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	
146	Cash - Construction Funds - Trustee													
147	Special Deposits	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	
148	Temporary Investments	36.79	43.72	47.55	28.93	21.54	18.19	6.85	10.29	14.51	9.25	17.26	22.25	
149	Accounts Receivable - Sales of Eergy (Net)	47.33	42.64	43.85	42.21	41.13	43.57	49.47	51.32	46.59	47.94	48.29	47.53	
150	Accounts Receivable - Other (Net)	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	5.28	
151	Fuel Stock	39.46	40.02	40.55	40.72	40.56	40.59	40.78	41.05	41.12	41.16	41.28	41.22	
152	Materials and Supplies - Other	21.09	21.14	21.19	21.24	21.30	21.35	21.40	21.46	21.51	21.57	21.62	21.67	
153	Prepayments	3.45	3.17	2.89	2.61	2.33	2.05	1.77	1.49	1.21	0.93	0.65	3.60	
154	Other Current and Accrued Assets	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	
155	TOTAL CURRENT AND ACCRUED ASSETS	156.54	159.11	164.44	144.13	135.26	134.16	128.69	134.02	133.35	129.26	137.51	144.69	
156														
157	Unamortized Debt Discount & Extraor. Prop. Losses	2.29	2.28	2.27	2.26	2.25	2.25	2.24	2.23	2.22	2.21	2.21	2.20	
158	Regulatory Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
159	Other Deferred Debits	6.67	6.67	6.67	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	6.66	
160	Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
161														
162	TOTAL ASSETS AND OTHER DEBITS	1,474.33	1,475.19	1,478.49	1,463.69	1,459.80	1,459.04	1,452.09	1,456.55	1,459.30	1,451.80	1,455.99	1,458.13	
163														
164														

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	Calendar Year	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
165	TOTAL MARGINS & EQUITY	389.35	389.90	386.82	381.08	375.66	375.58	378.72	383.03	384.21	386.13	388.49	391.24	
166														
167	Long-Term Debt - RUS	695.40	695.40	697.05	693.02	693.02	694.72	690.91	690.91	692.66	689.07	689.07	690.85	
168	Long-Term Debt - Other	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	142.10	
169	TOTAL LONG-TERM DEBT	837.50	837.50	839.15	835.12	835.12	836.82	833.01	833.01	834.76	831.17	831.17	832.95	
170														
171	Notes Payable													
172	Accounts Payable	29.97	28.96	33.58	34.66	33.82	31.56	31.43	31.64	30.94	30.78	30.83	28.86	
173	Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
174	Taxes Accrued	0.75	1.04	1.33	1.56	1.85	2.08	2.37	0.60	0.83	1.12	0.82	0.52	
175	Interest Accrued	3.62	6.73	8.51	3.50	6.93	8.54	3.60	7.02	8.58	3.59	6.89	8.56	
176	Other Current and Accrued Liabilities	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	9.41	
177	Other Current and Accrued Liabilities (Purchased Power)													
178	TOTAL CURRENT AND ACCRUED LIABILITIES	43.75	46.14	52.83	49.13	52.00	51.59	46.81	48.67	49.75	44.90	47.94	47.34	
179														
180	Deferred Credits	6.81	7.29	7.62	8.04	8.49	8.89	9.44	10.01	10.48	10.91	11.37	11.94	
181	Deferred Credits (Economic Reserve)	117.33	114.64	112.19	110.29	108.37	105.86	103.66	101.24	99.37	97.82	96.01	93.49	
182	Deferred Credits (Rural Economic Reserve)	61.82	61.91	62.01	62.10	62.20	62.29	62.39	62.49	62.59	62.69	62.78	62.88	
183	Accumulated Operating Provisions	17.78	17.82	17.87	17.91	17.96	18.00	18.05	18.09	18.14	18.18	18.23	18.27	
184	Obligation under Capital Leases - Noncurrent													
185														
186	TOTAL LIABILITIES AND OTHER CREDITS	1,474.33	1,475.19	1,478.49	1,463.69	1,459.80	1,459.04	1,452.09	1,456.55	1,459.30	1,451.80	1,455.99	1,458.13	
187														
188	Balance Check	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	
189	V. Cash Flow Statement (millions of $)													
190	Operating Receipts													
191	Rural	9.78	7.69	7.59	6.33	6.65	8.18	9.58	9.70	8.13	6.58	7.62	9.82	97.67
192	Large Industrial	2.57	3.24	2.56	2.56	2.71	2.65	2.79	2.89	2.75	2.82	2.75	2.74	33.03
193	Smelters	27.36	24.91	28.01	26.58	27.15	26.80	27.52	27.72	26.85	27.69	26.89	27.85	325.33
194	Offsystem	4.57	3.97	3.08	4.70	2.55	3.30	7.23	8.46	6.87	9.18	9.09	4.49	67.48
195	Lease Income													
196	Other Operating Revenues													
197	Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
198	Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
199	Interest Earnings	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.43
200	Total Receipts	44.31	39.86	41.29	40.21	39.10	40.96	47.16	48.81	44.63	46.30	46.39	44.92	523.96
201														
202	Operating Disbursements													
203	PPA													
204	Fuel Costs	22.86	20.54	20.26	19.94	18.31	17.55	22.98	24.08	22.21	23.46	23.56	22.56	258.31
205	Fuel Costs (Labor & Exp)	0.40	0.39	0.55	0.45	0.46	0.49	0.46	0.54	0.42	0.43	0.42	0.41	5.43
206	Domtar	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)
207	Power Supply (Purch. Power, APM, Cogen, & TVA Tran)	3.03	2.84	5.04	5.08	5.56	6.49	3.12	3.22	3.11	3.00	2.91	2.89	46.29
208	Production O&M	7.64	8.30	10.21	11.74	11.11	7.47	8.34	8.07	8.22	8.43	8.23	7.71	105.46
209	Transmission O&M	1.06	1.01	1.13	0.98	0.97	1.14	1.17	1.20	1.25	0.98	1.06	0.95	12.90
210	A&G	2.75	2.36	2.81	2.51	2.43	3.15	2.79	2.50	2.78	2.19	2.37	2.41	31.04
211	Working Capital	(0.63)	(4.22)	(3.96)	(3.21)	(0.78)	4.22	5.47	3.17	(4.51)	0.96	0.34	4.48	1.34
212	Other	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
213	Total Disbursements	37.10	31.20	36.04	37.50	38.06	40.51	44.34	42.77	33.48	39.45	38.90	41.41	460.77
214														
215	Operating Receipts less Disbursements	7.21	8.66	5.25	2.70	1.04	0.45	2.83	6.04	11.15	6.85	7.49	3.51	63.19
216														
217	Capital Expenditures													

	Calendar Year	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
218	Generation	3.77	2.21	1.48	8.46	8.29	4.12	3.14	3.97	7.77	0.60	0.17	0.00	43.97
219	Transmission	1.27	1.63	1.36	1.72	1.49	1.49	0.47	0.47	0.45	0.45	0.54	0.45	11.79
220	A&G	0.21	0.08	0.50	0.15	0.03	0.15	0.03	0.03	0.04	0.06	0.03	0.02	1.35
221	Other (HQ Building, IT)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
222	**Total Capital Expenditures**	**5.25**	**3.92**	**3.35**	**10.33**	**9.81**	**5.77**	**3.64**	**4.47**	**8.25**	**1.11**	**0.75**	**0.47**	**57.12**
223														
224	Income Taxes from Operations	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.25
225														
226	Net Pre-Finance Cash Flow	1.93	4.72	1.89	(7.65)	(8.79)	(5.34)	(0.83)	1.55	2.87	5.72	6.72	3.03	5.82
227														
228	Financing													
229	Principal	3.42	0.00	0.00	4.03	0.00	0.00	3.81	0.00	0.00	3.59	0.00	0.00	14.85
230	Interest	9.29	0.58	0.64	8.95	0.64	0.62	9.00	0.64	0.62	9.04	0.62	0.64	41.26
231	Debt Issuance Cost Bond Refunding	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
232	Line of Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
233	Aggregate Debt Service (incl. Line of Credit)	12.71	0.58	0.64	12.98	0.64	0.62	12.81	0.64	0.62	12.63	0.62	0.64	56.12
234														
235	Post-Finance Cash Flow	(10.77)	4.14	1.25	(20.62)	(9.43)	(5.96)	(13.65)	0.91	2.25	(6.91)	6.11	2.39	(50.29)
236														
237	Unwind Transaction													
238	Cash Proceeds													
239	Debt Reduction													
240	Misc. Transaction													
241	Net Before Member Reserves													
242	Station Two O&M Fund													
243	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
244	Economic Reserve	3.06	2.82	2.60	2.04	2.06	2.64	2.33	2.55	2.00	1.67	1.93	2.64	28.35
245	Net Before Transition Reserve	3.06	2.82	2.60	2.04	2.06	2.64	2.33	2.55	2.00	1.67	1.93	2.64	28.35
246														
247	**Ending Cash Balances (Incl. Transition Reserve)**	**72.42**	**79.38**	**83.23**	**64.64**	**57.28**	**53.96**	**42.64**	**46.11**	**50.36**	**45.12**	**53.16**	**58.18**	
248	**Ending Cash Balances (Excl. Transition Reserve)**	**37.03**	**43.97**	**47.79**	**29.17**	**21.78**	**18.44**	**7.10**	**10.53**	**14.75**	**9.49**	**17.50**	**22.50**	
249	Change in Working Capital													
250	Other Property	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
251	Accounts Receivable	1.08	(4.69)	1.21	(1.65)	(1.08)	2.44	5.90	1.86	(4.73)	1.35	0.34	(0.76)	1.28
252	Materials, Supplies & Other	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.64
253	Prepayments	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	(0.26)	2.97	0.08
254	Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
255	Accounts Payable	(1.23)	1.01	(4.62)	(1.08)	0.85	2.26	0.12	(0.21)	0.71	0.16	(0.05)	1.97	(0.11)
256	Taxes Accrued	(0.23)	(0.29)	(0.29)	(0.23)	(0.29)	(0.23)	(0.29)	1.77	(0.23)	(0.29)	0.30	0.30	(0.00)
257	Other Accruals	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.54)
258	Total	(0.63)	(4.22)	(3.96)	(3.21)	(0.78)	4.22	5.47	3.17	(4.51)	0.96	0.34	4.48	1.34
259														
260														

	Calendar Year	2011 January	2011 February	2011 March	2011 April	2011 May	2011 June	2011 July	2011 August	2011 September	2011 October	2011 November	2011 December	2011 Total
261	**VI. Credit Measures**													
262														
263	Contract TIER													
264	Earnings	2.85	0.55	(3.08)	(5.73)	(5.43)	(0.07)	3.13	4.32	1.18	1.92	2.36	2.76	4.74
265	Plus: Interest Expense	4.10	3.70	4.10	3.95	4.08	3.95	4.07	4.07	3.94	4.07	3.93	4.11	48.08
266	Plus: Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
267	Less: Offset to Imputed Rate Increase in 2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
268	Less: Interest on Sequestered Funds	(0.03)	(0.02)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.33)
269	Total	6.92	4.22	0.99	(1.81)	(1.37)	3.85	7.18	8.36	5.10	5.95	6.26	6.84	52.50
270	Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
271	Total	6.92	4.22	0.99	(1.81)	(1.37)	3.85	7.18	8.36	5.10	5.95	6.26	6.84	52.50
272	Divided by													
273	Interest Expense	4.10	3.70	4.10	3.95	4.08	3.95	4.07	4.07	3.94	4.07	3.93	4.11	48.08
274	Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
275	Total	4.10	3.70	4.10	3.95	4.08	3.95	4.07	4.07	3.94	4.07	3.93	4.11	48.08
276														
277	***Contract TIER***	**1.69**	**1.14**	**0.24**	**(0.46)**	**(0.34)**	**0.97**	**1.76**	**2.05**	**1.29**	**1.46**	**1.59**	**1.66**	**1.09**
278														
279	Conventional TIER													
280	Earnings	2.85	0.55	(3.08)	(5.73)	(5.43)	(0.07)	3.13	4.32	1.18	1.92	2.36	2.76	4.74
281	Plus: Interest Expense	4.10	3.70	4.10	3.95	4.08	3.95	4.07	4.07	3.94	4.07	3.93	4.11	48.08
282	Plus Income Tax													
283	Total	6.95	4.25	1.01	(1.78)	(1.34)	3.88	7.21	8.39	5.12	5.98	6.29	6.87	52.83
284	Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
285	Total	6.95	4.25	1.01	(1.78)	(1.34)	3.88	7.21	8.39	5.12	5.98	6.29	6.87	52.83
286	Divided by													
287	Interest Expense	4.10	3.70	4.10	3.95	4.08	3.95	4.07	4.07	3.94	4.07	3.93	4.11	48.08
288	Plus Sale-Leaseback Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
289	Total	4.10	3.70	4.10	3.95	4.08	3.95	4.07	4.07	3.94	4.07	3.93	4.11	48.08
290														
291	***Conventional TIER***	**1.70**	**1.15**	**0.25**	**(0.45)**	**(0.33)**	**0.98**	**1.77**	**2.06**	**1.30**	**1.47**	**1.60**	**1.67**	**1.10**
292														
293														
294														
295	North Star													
296	Total Cost of Electric Service (millions of $)	45.15	42.76	47.60	48.60	47.22	44.30	46.99	47.66	46.07	46.68	46.59	45.43	555.04
297	Non-Member Revenues (millions of $)	5.23	4.64	3.74	5.36	3.21	3.95	7.88	9.12	7.53	9.83	9.75	5.14	75.38
298		39.92	38.12	43.86	43.24	44.01	40.34	39.10	38.54	38.54	36.85	36.84	40.28	479.65
299														
300	Smelter and Non-Smelter Member Sales (TWh)	0.95	0.86	0.90	0.84	0.87	0.89	0.93	0.94	0.87	0.86	0.86	0.95	10.73
301	$/MWh	41.97	44.48	48.84	51.42	50.41	45.33	41.96	40.87	44.20	42.68	42.64	42.63	44.70
302	**$/kWh**	0.041974	0.044480	0.048837	0.051419	0.050412	0.045330	0.041955	0.040871	0.044197	0.042681	0.042638	0.042627	0.044704

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	Calendar Year	2012	2013
1			
2	**I. Sales (TWH)**		
3			
4	Rural	2.52	2.55
5			
6	Large Industrial	0.95	0.95
7			
8	Century	4.13	4.13
9			
10	Alcan	3.16	3.16
11			
12	Market	1.19	1.05
13			
14	Total Sales	11.95	11.84
15			
16	**II. Rates, Accrual Based ($/ MWH Sold, unless otherwise n**		
17			
18	General Rate Adjustment (%)	11.75%	0.00%
19			
20	**Rural**		
21	Load Factor (%)	63.61%	64.04%
22	Demand ($/ KW-mo.)	8.24	8.24
23	Energy ($/ MWH)	22.80	22.80
24	Net Rate ($/ MWH)	40.48	40.42
25			
26	MRDA	0.00	0.00
27	Regulatory Charge	(1.15)	(1.14)
28	FAC	12.38	13.21
29	Environmental Surcharge	3.24	3.41
30	Surcredit	(3.93)	(3.90)
31	Total	11.68	12.72
32	Economic Reserve	(6.68)	(6.72)
33	Rural Economic Reserve	0.00	0.00
34	TIER Related Rebate	0.00	0.00
35	Effective Rate ($/ MWH)	44.34	45.28
36			
37	**Large Industrial**		
38	Load Factor (%)	76.91%	77.12%
39	Demand ($/ KW-mo.)	11.34	11.34
40	Energy ($/ MWH)	15.33	15.33
41	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00
42	Net Rate ($/ MWH)	35.47	35.47
43			
44	MRDA	0.00	0.00
45	Regulatory Charge	(1.15)	(1.14)
46	FAC	12,38	13.21
47	Environmental Surcharge	3.24	3.41
48	Surcredit	(3.93)	(3.90)
49	Total	11.68	12.72
50	Economic Reserve	(6.68)	(6.72)
51	TIER Related Rebate	0.00	0.00
52	Effective Rate ($/ MWH)	39.33	40.34
53			

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	Calendar Year	2012	2013
54	**Non-Smelter Member Blend**		
55	Net Rate ($/ MWH)	39.11	39.08
56			
57	MRDA	0.00	0.00
58	Regulatory Charge	(1.15)	(1.14)
59	FAC	12.38	13.21
60	Environmental Surcharge	3.24	3.41
61	Surcredit	(3.93)	(3.90)
62	Total	11.68	12.72
63	Economic Reserve	(6.68)	(6.72)
64	Rural Economic Reserve	0.00	0.00
65	TIER Related Rebate	0.00	0.00
66	Effective Rate ($/ MWH)	42.97	43.94
67			
68	**Smelters**		
69	Base Rate ($/ MWH)	31.39	31.43
70	TIER Adjustment	2.77	2.90
71	Smelter Rate Subject to Price Cap	34.16	34.33
72	Non-FAC PPA	(1.75)	(1.75)
73	FAC	12.38	13.21
74	Environmental Surcharge	3.24	3.41
75	Surcharge 1	0.67	0.67
76	Surcharge 2	1.20	1.20
77	TIER Related Rebate	0.00	0.00
78	Effective Rate ($/ MWH)	49.90	51.08
79			
80	<u>Market ($/ MWH)</u>	47.51	47.68
81			
82	**<u>III. Statement of Operations (millions of $)</u>**		
83			
84	Electric Energy Revenues	592.54	599.93
85	Income From Leased Property Net	0.00	0.00
86	Other Operating Revenue and Income	7.48	7.48
87	TOTAL OPER. REVENUES & PATRONAGE CAPITAL	600.03	607.41
88			
89	Operating Expense-Production-Excluding Fuel	65.65	67.82
90	Operating Expense-Production-Fuel	221.86	233.70
91	Operating Expense-Other Power Supply	104.83	98.21
92	Operating Expense-Transmission	8.26	8.51
93	Operating Expense-Distribution		
94	Operating Expense-Customer Accounts		
95	Operating Expense-Customer Service and Information	0.79	0.81
96	Operating Expense-Sales	1.81	1.82
97	Operating Expense-Administrative and General	29.55	29.68
98	TOTAL OPERATION EXPENSE	432.75	440.55
99			
100	Maintenance Expense-Production	59.82	53.75
101	Maintenance Expense-Transmission	4.76	4.97
102	Maintenance Expense-Distribution		
103	Maintenance Expense-General Plant	0.17	0.18
104	TOTAL MAINTENANCE EXPENSE	64.75	58.90
105			
106	Depreciation and Amortization Expense	42.90	44.14
107	Taxes	0.00	0.00
108	Interest on Long-Term Debt	48.58	51.94
109	Interest Charged to Construction - Credit	(0.70)	(0.71)
110	Other Interest Expense		

	Calendar Year	2012	2013
111	Asset Retirement Obligation		
112	Other Deductions	0.14	0.23
113			
114	TOTAL COST OF ELECTRIC SERVICE	588.43	595.04
115			
116	OPERATING MARGINS	11.59	12.37
117			
118	Interest Income	0.40	0.43
119	Allowance For Funds Used During Construction		
120	Income (Loss) From Equity Investments		
121	Other Non-Operating Income (Net)		
122	Generation and Transmission Capital Credits		
123	Other Capital Credits and Patronage Dividends	0.00	0.00
124	Extraoridinary Items		
125	NET PATRONAGE CAPITAL OR MARGIN	11.99	12.80
126			
127			
128	**IV. Balance Sheet (millions of $)**		
129	Total Utility Plant in Service	2,131.80	2,186.18
130	Construction Work in Progress	25.00	25.00
131	Total Utility Plant	2,156.80	2,211.18
132	Accum. Provision for Depreciation and Amort.	1,028.06	1,074.59
133	NET UTILITY PLANT	1,128.75	1,136.59
134			
135	Non-Utility Property (Net)		
136	Invest. In Assoc. Org - Patronage Capital	3.58	2.78
137	Invest. In Assoc. - Other - General Funds	0.68	0.68
138	Other Investments	0.02	0.02
139	Special Funds	0.65	0.65
140	Special Funds (Transition Reserve)	36.01	36.35
141	Special Funds (Economic Reserve)	71.70	49.22
142	Special Funds (Rural Economic Reserve)	64.06	65.26
143	TOTAL OTHER PROPERTY AND INVESTMENTS	176.70	154.95
144			
145	Cash - General Funds	0.24	0.24
146	Cash - Construction Funds - Trustee		
147	Special Deposits	0.57	0.57
148	Temporary Investments	31.81	23.32
149	Accounts Receivable - Sales of Eergy (Net)	49.37	49.97
150	Accounts Receivable - Other (Net)	5.28	5.28
151	Fuel Stock	42.67	44.17
152	Materials and Supplies - Other	22.32	22.99
153	Prepayments	3.49	3.50
154	Other Current and Accrued Assets	2.31	2.31
155	TOTAL CURRENT AND ACCRUED ASSETS	158.08	152.37
156			
157	Unamortized Debt Discount & Extraor. Prop. Losses	3.57	4.39
158	Regulatory Assets	0.00	0.00
159	Other Deferred Debits	6.66	6.65
160	Accumulated Deferred Income Taxes	0.00	0.00
161			
162	TOTAL ASSETS AND OTHER DEBITS	1,473.75	1,454.95
163			
164			

Calendar Year	2012	2013
TOTAL MARGINS & EQUITY	403.23	416.03
Long-Term Debt - RUS	622.06	609.30
Long-Term Debt - Other	227.10	227.10
TOTAL LONG-TERM DEBT	849.16	836.40
Notes Payable		
Accounts Payable	34.32	34.06
Accounts Payable (TIER Rebate)	0.00	0.00
Taxes Accrued	0.45	0.45
Interest Accrued	8.56	8.56
Other Current and Accrued Liabilities	9.41	9.41
Other Current and Accrued Liabilities (Purchased Power)		
TOTAL CURRENT AND ACCRUED LIABILITIES	52.74	52.48
Deferred Credits	14.03	16.18
Deferred Credits (Economic Reserve)	71.70	49.22
Deferred Credits (Rural Economic Reserve)	64.06	65.26
Accumulated Operating Provisions	18.82	19.39
Obligation under Capital Leases - Noncurrent		
TOTAL LIABILITIES AND OTHER CREDITS	1,473.75	1,454.95
Balance Check	(0.00)	(0.00)
V. Cash Flow Statement (millions of $)		
Operating Receipts		
Rural	111.71	115.60
Large Industrial	37.38	38.34
Smelters	363.88	372.44
Offsystem	56.36	50.00
Lease Income		
Other Operating Revenues		
Gain on Sale of Allowances	0.00	0.00
Other	0.02	0.02
Interest Earnings	0.40	0.43
Total Receipts	569.75	576.84
Operating Disbursements		
PPA		
Fuel Costs	253.83	265.36
Fuel Costs (Labor & Exp)	5.50	5.79
Domtar	(0.02)	0.02
Power Supply (Purch. Power, APM, Cogen, & TVA Tran)	56.94	50.26
Production O&M	125.47	121.57
Transmission O&M	13.02	13.48
A&G	32.32	32.49
Working Capital	(3.35)	0.27
Other	0.02	0.02
Total Disbursements	483.73	489.24
Operating Receipts less Disbursements	86.03	87.60
Capital Expenditures		

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	Calendar Year	2012	2013
218	Generation	56.41	49.16
219	Transmission	6.26	3.13
220	A&G	3.01	1.38
221	Other (HQ Building, IT)	0.00	0.00
222	**Total Capital Expenditures**	**65.68**	**53.67**
223			
224	Income Taxes from Operations	0.00	0.00
225			
226	Net Pre-Finance Cash Flow	20.34	33.93
227			
228	Financing		
229	Principal	(8.92)	20.48
230	Interest	41.08	44.13
231	Debt Issuance Cost Bond Refunding	1.49	1.03
232	Line of Credit	0.00	0.00
233	Aggregate Debt Service (incl. Line of Credit)	33.65	65.64
234			
235	Post-Finance Cash Flow	(13.31)	(31.71)
236			
237	Unwind Transaction		
238	Cash Proceeds		
239	Debt Reduction		
240	Misc. Transaction		
241	Net Before Member Reserves		
242	Station Two O&M Fund		
243	Rural Economic Reserve	0.00	0.00
244	Economic Reserve	23.19	23.56
245	Net Before Transition Reserve	23.19	23.56
246			
247	**Ending Cash Balances (Incl. Transition Reserve)**	**68.06**	**59.91**
248	**Ending Cash Balances (Excl. Transition Reserve)**	**32.05**	**23.57**
249	Change in Working Capital		
250	Other Property	0.00	(0.80)
251	Accounts Receivable	1.84	0.60
252	Materials, Supplies & Other	0.65	0.67
253	Prepayments	0.10	0.10
254	Other Current Assets	0.00	0.00
255	Accounts Payable	(5.46)	0.27
256	Taxes Accrued	0.06	(0.00)
257	Other Accruals	(0.55)	(0.56)
258	Total	(3.35)	0.27
259			
260			

	Calendar Year	2012	2013
261	**VI. Credit Measures**		
262			
263	Contract TIER		
264	Earnings	11.99	12.80
265	Plus: Interest Expense	48.58	51.94
266	Plus: Imputed Rate Increase in 2010	0.00	0.00
267	Less: Offset to Imputed Rate Increase in 2010	0.00	0.00
268	Less: Interest on Sequestered Funds	(0.33)	(0.33)
269	Total	60.24	64.40
270	Plus Sale-Leaseback Interest	0.00	0.00
271	Total	60.24	64.40
272	Divided by		
273	Interest Expense	48.58	51.94
274	Plus Sale-Leaseback Interest	0.00	0.00
275	Total	48.58	51.94
276			
277	*Contract TIER*	**1.24**	**1.24**
278			
279	Conventional TIER		
280	Earnings	11.99	12.80
281	Plus: Interest Expense	48.58	51.94
282	Plus Income Tax		
283	Total	60.57	64.73
284	Plus Sale-Leaseback Interest	0.00	0.00
285	Total	60.57	64.73
286	Divided by		
287	Interest Expense	48.58	51.94
288	Plus Sale-Leaseback Interest	0.00	0.00
289	Total	48.58	51.94
290			
291	*Conventional TIER*	**1.25**	**1.25**
292			
293			
294			
295	North Star		
296	Total Cost of Electric Service (millions of $)	588.43	595.04
297	Non-Member Revenues (millions of $)	64.23	57.91
298		524.20	537.13
299			
300	Smelter and Non-Smelter Member Sales (TWh)	10.76	10.80
301	$/MWh	48.71	49.75
302	**$/kWh**	**0.048708**	**0.049754**

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

DIRECT TESTIMONY

OF

ALBERT M. YOCKEY
VICE PRESIDENT, GOVERNMENTAL RELATIONS AND ENTERPRISE RISK MANAGEMENT

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
ALBERT M. YOCKEY

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DIRECT TESTIMONY
OF
ALBERT M. YOCKEY

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Albert M. Yockey. My business address is 201 Third Street, Henderson, Kentucky 42420. I am employed by Big Rivers Electric Corporation ("Big Rivers") as its Vice President, Governmental Relations and Enterprise Risk Management.

Q. Have you previously appeared before this Commission or other regulatory entities?

A. Yes. I appeared before this Commission on behalf of Big Rivers in Case No. 2008-00408 (Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007). I have participated in various informal conferences at the Commission including the recent Midwest ISO case and have assisted in preparing data responses in Big Rivers Fuel Adjustment Clause ("FAC") and Environmental Surcharge ("ES") cases before this Commission. Prior to my arrival at Big Rivers, my career included interfacing with numerous state commissions, and their respective staffs, during my tenure with American Electric Power ("AEP") in Columbus, Ohio. These commissions were across the AEP footprint. I assisted in the preparation of testimony for AEP rate proceedings in Texas and Oklahoma. I have not previously sponsored direct testimony before this Commission.

Q. Briefly describe your education and professional certifications.

A. I received a Bachelor of Science in Electrical Engineering, Cum Laude, from the University of Pittsburgh in April, 1972. In May, 1979, I received a Master of Science in Electrical Engineering from Lehigh University. In May, 1994, I was awarded a Juris

Doctorate from The Capital University in Columbus, Ohio. I am a registered attorney in the State of Ohio and a registered Professional Engineer in the Commonwealth of Pennsylvania.

Q. Briefly describe your work experience before coming to Big Rivers.

A. While working on my undergraduate degree at the University of Pittsburgh, I worked as a summer laborer and engineering aide at the West Penn Power Company's Springdale Power Station. Upon graduating from the University of Pittsburgh, I was employed by the Pennsylvania Power & Light Company ("PP&L") as a Relay Engineer in the System Operating Department in 1972 and was promoted to a Project Engineer in 1976. The focus of my work was system projection and related requirements. From 1977 – 1981, I was a Project Engineer in the Electrical Section of System Planning. Among many duties, I ran computer simulation of electrical systems, performed economic analysis of alternative expansion plans, and developed five-year and long-range plans for system reinforcements. As a Project Engineer in Energy Assessment and Capacity Planning Section of System Planning from 1981 – 1985, I made economic evaluations of co-generation and alternative energy projects, assessed various energy and demand management options, and reviewed potential capacity and energy sales to other utilities.

In 1985, I accepted a position as Senior Engineer in the Area Transmission Planning Section of the System Planning Department of AEP Service Corporation in Columbus, Ohio. My responsibilities included ensuring reliable operation of transmissions facilities under normal and facility outage conditions, identifying future system requirements, and justifying needed changes to management. As such, I worked with many internal cross-functional teams, external customers, other utilities, and regulatory agencies. In 2000 I became the Manager of Transmission Strategic Issues reporting to the Vice President of Transmission Asset Management. My responsibilities included divisional regulatory/legislative strategy development and coordination. More specifically, I managed multiple state and federal requirements which required interfacing, as needed, with AEP departments within and outside transmission, and with commissions and their respective staffs across the AEP footprint. I held that position until 2008 when I came to Big Rivers.

Q. Briefly describe your responsibilities at Big Rivers.

A. As the Vice President, Governmental Relations and Enterprise Risk Management I am responsible for risk management and all government relations, including environmental and regulatory agencies. My responsibilities for the risk management function are more fully described in Section V – RISK MANAGEMENT PLAN AND PROGRAM.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony describes the changes which Big Rivers' application proposes to make to its current tariff on file with this Commission. I also update the Commission on a number of Big Rivers' regulatory filings since the closing of the Unwind Transaction approved by this Commission in its Order dated March 6, 2009, in Case No. 2007-00455. I also describe Big Rivers' risk management plan and program. Finally, my testimony supports some of the filing requirements listed in 807 KAR 5:001.

III. DESCRIPTION OF TARIFF CHANGES

Q. Please summarize the major changes or additions Big Rivers is proposing to its existing tariff.

A. Big Rivers is proposing essentially five changes/additions to its tariffs First, Big Rivers is reorganizing its tariff to include a General Index reflecting the major sections of the tariff and listing the components of each section. I will describe below the reason for this reorganization later in my testimony. Next, Big Rivers is proposing adjustments to its rates. The proposed rate adjustments are more fully described in the direct testimony of Mr. William Steven Seelye. Third, Big Rivers is proposing to modify its Member Rate Stability Mechanism ("MRSM") tariff in order to expand the time frame beyond 48 months in which the Economic Reserve will be exhausted. Mr. Seelye provides more details regarding this in his Direct Testimony. Fourth, Big Rivers is proposing to modify the Rural Economic Reserve Rider to eliminate the 24 month schedule and replace it with a mechanism which is intended to use the credit as intended by the Commission, but at the same time modify the Rural Economic Reserve to operate seamlessly with the MRSM as more fully described in Mr. Seelye's Direct Testimony. Fifth, Big Rivers is proposing a new tariff, the Non-Smelter Non-FAC PPA tariff, similar to the one approved by the Commission in regard to the Smelters in Case No. 2007-00455. The purpose of this tariff is to provide for the annual amortization of the Regulatory Account balance (approved by the Commission) to Big Rivers' Members over a 12 month period, except for the initial amortization of the current Regulatory Liability balance, which will be distributed over a 24 month period. Mr. Seelye further explains the details of this tariff in his direct testimony.

Tariff Reorganization

Q. Please describe the reorganization Big Rivers is making to its tariff.

A. Big Rivers' Proposed Tariff reflects two reorganization components compared to its current tariff. First, the Proposed Tariff includes a General Index which allows the reader to more readily find information of interest. Second, the Proposed Tariff is divided into four major sections to also facilitate greater ease in locating information.

Q. Please describe the General Index of the Proposed Tariff.

A. The General Index functions as a table of contents allowing any reader to more easily find information of interest. It lists the contents of each of the four sections of the Proposed Tariff. Each standard rate, adjustment clause, and service rider, is listed by name along with an acronym for each. For example, Rural Delivery Service is a standard rate represented by the acronym RDS while the Fuel Adjustment Clause is represented as FAC.

For each standard rate, adjustment clause, and service rider, the Proposed Tariff includes a Sheet Number and Effective Date. The Sheet Number facilitates locating that rate, clause, or rider within the overall tariff. The Effective Date allows any reader to readily know the effective date for each component of the Proposed Tariff. Finally, the General Index lists the location for other Terms and Conditions and a listing of Abbreviations and Acronyms.

Q. Please describe the four major sections of the Proposed Tariff.

A. Section 1 lists Big Rivers' standard rates such as the rates for Rural Delivery Service, Large Industrial Customers, and Cable Television Attachments. Each tariff in Section 1 includes a listing of those adjustment clauses and service riders which apply to the tariff.

Section 2 lists those adjustment clauses and service riders such as the Fuel Adjustment Clause, the Environmental Surcharge, and the Unwind Surcredit. Each adjustment clause or service rider in Section 2 includes a listing of those standard rates to which the adjustment clause or service rider applies.

Section 3 contains the general terms and conditions which apply to Section 1 and Section 2 unless specifically stated elsewhere in the tariff. These general terms and conditions address, among other things, contract demand, metering, substations, notice of meter reading or test, right of access, and payment of bills.

Finally, Section 4 includes a listing of the abbreviations and acronyms common to Section 1, Section 2, and Section 3.

Q. Have you summarized the tariff changes in any way?

A. Yes. As required in 807 KAR 5:001 Section 10(1)(a)(8), Big Rivers has presented its Current Tariff and the Proposed Tariff in a side-by-side comparison. (See Exhibit 8.) To facilitate this comparison in some cases, blank sheets have been used and labeled **'This Page is Blank'**.

Q. Please describe the changes made to the Rural Delivery Service tariff.

A. The existing Standard Rate for Electric Service tariff covering rural members will be renamed STANDARD RATE – RDS – Rural Delivery Service. This tariff, along with the name change, will include the demand and energy charge as well as adjustment charges and riders applicable under this tariff for rural delivery service. The tariff must be modified to amend the Demand Charge definition, to include the Non-Smelter Non-FAC PPA adjustment clause, and to include references to certain numerical paragraphs. The reference changes are simply to make the tariff accurate due to the elimination of numbered paragraphs.

Q. Did Big Rivers propose any substantive changes to the rate design of any other tariffs?

A. No. Big Rivers is not proposing structural or rate design changes for the other tariffs. For these tariffs, Big Rivers is only proposing to revise the actual rates in the tariffs, as described by Mr. Seelye in his Direct Testimony.

IV. <u>REGULATORY FILINGS UNDERTAKEN SINCE JULY 2009</u>

Q. Following the closing of the Unwind Transaction, did Big Rivers undertake or resume responsibility for certain regulatory filings?

A. Yes. These include but are not limited to the Fuel Adjustment Clause, the Environmental Surcharge, and the Integrated Resource Plan. I describe these items below.

Fuel Adjustment Clause

Q. Please describe Big Rivers' Fuel Adjustment Clause.

A. Big Rivers' current FAC was approved by the Commission in its Order dated March 6, 2009, in Case No. 2007-00455, the Unwind Transaction Order. In Case No. 2007-00455, Big Rivers sought to reinstate a FAC since, as a result of the Unwind Transaction, it would resume control of, and operate, its power plants. The FAC permits Big Rivers to timely track changes in its fuel costs consistent with the Commission's FAC regulations.

Q. Has the Commission reviewed the performance of Big Rivers' FAC since the close of the Unwind Transaction?

A. Yes. Since July 17, 2009, the Commission has conducted two reviews of Big Rivers' FAC. The first review was in Case No. 2009-00510; the second review was in Case No. 2010-00269. The two-year review of the FAC in Case No. 2010-00495 is currently underway. In that proceeding, Big Rivers is proposing to increase the base cost used in the FAC by $0.010212/kWh. Big Rivers will incorporate the effect of the "roll-in" of the FAC authorized in Case No. 2010-00495 in the compliance rates filed with the Commission pursuant to an order in this proceeding.

Q. What were the results of these reviews?

A. By its Order dated May 17, 2010, in Case No. 2009-00510, the Commission approved the charges and credits billed by Big Rivers through its FAC for the period July 17, 2009 through October 31, 2009. By its order dated December 15, 2010, in Case No.

2010-00269, the Commission approved the charges and credits billed by Big Rivers through its FAC for the period November 1, 2009 through April 30, 2010.

Environmental Surcharge

Q. Please describe Big Rivers' Environmental Surcharge.

A. Big Rivers' ES and the related compliance plan were approved by the Commission in its Order dated June 25, 2008, in Case No. 2007-00460. The ES became effective at the time of the Unwind, July 17, 2009. Big Rivers' compliance plan includes programs and the associated costs dealing with the control of sulfur dioxide, nitrogen oxide, and sulfur trioxide. At this time, Big Rivers only recovers certain variable operating expenses associated with its environmental compliance programs. Big Rivers' ES does not include any capital projects or investments in utility plant to comply with the requirements of federal, state, or local environmental statutes or regulations. Big Rivers is not requesting any changes to its ES compliance plan or recovery mechanism in this application.

Q. Has the Commission reviewed the performance of Big Rivers' ES since the close of the Unwind Transaction?

A. Yes. Since March 6, 2009, the Commission has conducted two reviews of Big Rivers' ES. The first review was in Case No. 2010-00194; the second review was in Case No. 2010-00368.

Q. What were the results of these reviews?

A. By its Order dated October 7, 2010, in Case No. 2010-00194, the Commission approved the amounts billed by Big Rivers through its environmental surcharge for the period August 1, 2009 through January 31, 2010. Furthermore, the Commission found Big Rivers' calculation of any over- or under-recovery for the review period to be reasonable. It also found no need for any subsequent adjustments to Big Rivers' environmental costs as a result of its review.

The Commission opened Case No. 2010-00368 by its Order dated October 14, 2010. As of the filing date of this General Rate Application, this ES review case remains open.

Integrated Resource Plan

Q. Has Big Rivers filed an Integrated Resource Plan ("IRP") with the Commission since the close of the Unwind Transaction?

A. Yes. As required by Commitment No. 13 in Appendix A of the Commission's Order, dated March 6, 2009, in Case No. 2007-00455, Big Rivers filed its 2010 IRP with the Commission on November 15, 2010. The Commission has assigned Case No. 2010-00443 to the 2010 IRP review.

Q. What is the current status of the Commission Staff's review of the 2010 IRP?

A. On November 24, 2010, Big Rivers filed a corrected two-page table from Appendix B of its 2010 IRP with the Commission. On December 20, 2010, the Commission issued a procedural schedule for the review of its 2010 IRP. As of the filing of this general Rate Application, Big Rivers has filed its responses to initial and supplemental data requests of the KPSC and the Initial data requests from the AG which did not submit a supplemental set of data requests. Case No. 2010-00443 remains open.

V. <u>RISK MANAGEMENT PLAN AND PROGRAM</u>

General Description

Q. Why has Big Rivers implemented a Risk Management Plan and Program?

A. Big Rivers implemented the Risk Management Plan and Program because it is good business practice, it told the Commission it intended to do so and then complied with the Commission's order by making a filing to comply with Commitment No. 16 in Appendix A of the Commission's Order, dated March 6, 2009, in Case No. 2007-00455.

Q. Has Big Rivers provided any update to the Commission about this Risk Management Plan and Program?

A. Yes. By letter dated October 14, 2009, Big Rivers informed the Commission that it had the Risk Management Plan and Program in place, and that the program gave Big Rivers the ability to identify and address material risks affecting it. Big Rivers committed to funding and maintaining the plan and program.

Q. Please describe Big Rivers' Risk Management Plan and Program.

A. Big Rivers has given significant thought and effort to creating a Risk Management Plan and implementing a comprehensive Risk Management Program for the organization. Since the closing of the Unwind Transaction on July 16, 2009, Big Rivers has implemented a corporate Enterprise Risk Management Policy, an Internal Risk Management Committee, and completed/updated and implemented various risk management-related company policies. The Internal Risk Management Committee commenced monthly meetings in October 2009. From those meetings an agenda of topics and policy updates are prepared for the Big Rivers Board of Directors ("Board") review, input, and approval as appropriate. My department acts as the coordinator in bringing emerging issues involving risk for discussion of the senior staff at the monthly Internal Risk Management Committee meetings.

Q. Does Big Rivers' Risk Management Plan and Program include actions or steps to address the potential closure or loss of one or both of the Smelters?

A. Yes. These steps are outlined in the Direct Testimony of Mr. C. William Blackburn in Exhibit 49.

Enterprise Risk Management Policy

Q. Please describe Big Rivers' Enterprise Risk Management ("ERM") Policy.

A. The ERM Policy discusses the structure and responsibilities of Big Rivers' risk governance. Risk governance follows a top-down approach whereby the Board identifies Big Rivers' risk management objectives and provides risk management oversight. Supporting controls, policies and procedures are implemented and aligned throughout the risk governance structure, with distinct roles and responsibilities that result in a risk control environment. Governance and controls include the organizational structure, policies, reporting process and procedures that support Big Rivers' business models, risk tolerances, power supply objectives, financial objectives, safety objectives, and segregate responsibilities appropriately.

Q. What are the major components of the ERM Policy?

A. Big Rivers' ERM Policy is quite extensive. It sets forth the Company's

1. risk management objectives,
2. risk governance structure and responsibilities,
3. the scope of business activities governed by the ERM policy, and
4. the list of associated ERM guidelines and policy documents, including the supporting risk management policies.

Q. Does the ERM Policy set forth risk management objectives for Big Rivers?

A. Yes. The ERM Policy sets forth the following risk management objectives for Big Rivers:

1. to maintain risk within desired tolerances for a defined period in the future;
2. to mitigate price volatility to the Members;

3. to maintain a proactive safety, health, and loss prevention program designed to protect life and property, provide a hazard-controlled work environment, and comply with all applicable regulations;
4. to meet lender debt covenants;
5. to maintain financial liquidity within desired tolerances;
6. to maintain an investment grade credit rating;
7. to enhance the value of Big Rivers' assets/resources;
8. to ensure that the risks of economic development and other business opportunities are effectively managed to increase the value of Big Rivers to its Members; and
9. to participate in commodity markets and derivative instruments for hedging and not for speculative purposes, and to develop an ERM culture throughout the organization and provide for an ongoing strategic planning process.

Internal Risk Management Committee

Q. Please describe Big Rivers' Internal Risk Management Committee ("IRMC").

A. The IRMC establishes a forum for discussing Big Rivers' significant risks and developing guidelines required to implement an appropriate risk management control infrastructure, including implementing and monitoring of compliance with Big Rivers' ERM-related policies. The IRMC executes its risk management responsibilities through direct oversight and prudent delegation of its responsibilities to the independent risk management function, as well as to other Big Rivers personnel. This committee meets on a monthly basis.

Q. Please describe the composition of the IRMC.

A. Big Rivers' Internal Risk Management Committee is comprised of the:

1. President and Chief Executive Officer;
2. Senior Vice President, Financial and Energy Services and Chief Financial Officer;
3. Vice President, Production;
4. Vice President, Accounting;
5. Vice President, Administrative Services;
6. Vice President, System Operations;
7. Communications and Community Relations Manager; and
8. Vice President, Governmental Relations and Enterprise Risk Management (non-voting member).

As the Vice President, Governmental Relations and Enterprise Risk Management, I am a non-voting member of the committee and serve as the IRMC chairperson. The chairperson is responsible for keeping, or causing to be kept, a true and complete record of the proceedings. Other non-voting participants participate in the meetings as determined by the voting committee members identified above

Other Enterprise Risk Management Guidelines and Policies

Q. Has Big Rivers implemented other policies to complement its Risk Management Plan and Program?

A. Yes. Big Rivers has drafted numerous policies to accommodate the Company's need for well-defined risk management policies and procedures. The following policies are included in the additions/updates made by Big Rivers to provide adequate risk management policies for the organization:

1. Energy Related Transaction Authority Policy;
2. Risk Management Sanctions Policy;
3. Hedge Policy;
4. Financial Policy;
5. Credit Policy;
6. Economic Development Policy;
7. Safety Policy;
8. Energy Risk Identification and Exposure Management Guidelines; and
9. Whistleblower Policy.

Risk Management Function and Staffing

Q. Please describe the overall risk management function and how it is staffed.

A. As Vice President, Governmental Relations and Enterprise Risk Management, I have overall responsibility for leading Big Rivers' risk management function. As outlined above, the Company's ERM Policy and its IRMC are integral components of that function. Finally, I am assisted in leading the risk management function by the Director, Risk Management/Strategic Planning who reports to me.

Q. Briefly describe the Director, Risk Management/StrategicPlanning position.

A. The Director, Risk Management/Strategic Planning regularly assimilates all reports and information from various Big Rivers' departments which are responsible for 'frontline' management of the Company's risk. The Director, Risk Management/Strategic Planning regularly analyzes and assesses this information. The results of this analysis and these assessments are regularly shared with me and the IRMC. The Director, Risk Management/Strategic Planning also attends IRMC meetings and regularly provides information to, and coordinates and/or conducts analysis for, the IRMC. The current Director, Risk Management/Strategic Planning has a Masters in Business Administration, and is a Certified Public Accountant. She also has over twelve years of diverse experience in both electric cooperatives and investor-owned utilities.

Conclusion

Q. Does the Risk Management Plan and Program help Big Rivers identify and address the impact of contingencies including, but not limited to, fuel prices, cost exposure for environmental remediation programs (both existing and contemplated), and any other material risks pertaining to Big Rivers?

A. Yes. The IRMC reviews and discusses all significant issues related to Big Rivers at its monthly meeting. Fuel prices are monitored in a plethora of ways within the Company, but direct interaction of the ERM group occurs with all fuel contracts that are initiated. The ERM group works to ensure that all authorities are in place and that the contracts are consistent with Big Rivers' Hedging Policy.

Likewise, environmental issues are key issues reviewed by the IRMC. Although these issues receive significant attention from Big Rivers' Senior Staff, the ERM group is still heavily involved in the analysis and monitoring of environmental issues, both current and pending, and their potential impacts on the Company. Currently, the Director Risk Management/Strategic Planning chairs the Environmental Compliance Group at Big Rivers.

Other material risks to Big Rivers are monitored and the involvement of the ERM group in activities across the Company helps to identify and quantify the potential impacts of those risks on the operations/viability of the organization.

VI. FILING REQUIREMENTS FROM 807 KAR 5:001

Q. Have you reviewed the answers provided in Exhibits 1-47, which address Big River's compliance with historical period filing requirements under KAR 5:001 and its various subsections?

A. Yes I have and I hereby incorporate and adopt those portions of Exhibits 1-47 for which I am identified as the sponsoring witness as part of this Direct Testimony.

Q. What filing requirements from 807 KAR 5:001 are you sponsoring?

A. I am sponsoring Big Rivers' responses to the filing requirements listed in

1. 807 KAR 5:001 Section 10(1)(a)7,
2. 807 KAR 5:001 Section 10(1)(a)8,
3. 807 KAR 5:001 Section 10(1)(a)9,
4. 807 KAR 5:001 Section 10(2),
5. 807 KAR 5:001 Section 10(3),
6. 807 KAR 5:001 Section 10(4)(a),
7. 807 KAR 5:001 Section 10(4)(b),
8. 807 KAR 5:001 Section 10(4)(c),
9. 807 KAR 5:001 Section 10(4)(d),
10. 807 KAR 5:001 Section 10(4)(f),
11. 807 KAR 5:001 Section 10(4)(g), and
12. 807 KAR 5:001 Section 10(5).

807 KAR 5:001 Section 10(1)(a)7

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(1)(a)7.

A. As required by 807 KAR 5:001 Section 10(1)(a)7, Big Rivers' Proposed Tariff complies with 807 KAR 5:011.The Proposed Tariff's effective date is April 1, 2011, which is thirty days of the filing date of this General Rate Application.

807 KAR 5:001 Section 10(1)(a)8

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(1)(a)8.

A. As required by 807 KAR 5:001 Section 10(1)(a)8, Big Rivers' is presenting its Current Tariff and its Proposed Tariff as a side-by-side, comparative format. This is provided in Exhibit 8.

807 KAR 5:001 Section 10(1)(a)9

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(1)(a)9.

A. Big Rivers has provided the statement of customer notice to its Member Cooperatives as required by 807 KAR 5:001 Section 10(1)(a)9. Big Rivers mailed the notice to its Members on February 28, 2011, and included the information enumerated in 807 KAR 5:001 Section 10(3).

807 KAR 5:001 Section 10(2)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(2).

A. To comply with 807 KAR 5:001 Section 10(2), Big Rivers filed its Notice of Intent with the Commission on January 31, 2011. That notice stated that Big Rivers' application would be supported by a historical test year. This notice was also served on the Attorney General's Office of Rate Intervention.

807 KAR 5:001 Section 10(3)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(3).

A. Big Rivers has provided notice to its Members required by 807 KAR 5:001 Section 10(3). See the response for 807 KAR 5:001 Section 10(1)(a)9 above.

807 KAR 5:001 Section 10(4)(a)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(4)(a).

A. 807 KAR 5:001 Section 10(4)(a) is not applicable to Big Rivers.

807 KAR 5:001 Section 10(4)(b)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(4)(b).

A. Big Rivers has provided the necessary notice, which was mailed to its Members on February 28, 2011 and included the information enumerated in 807 KAR 5:001 Section 10(3). See the response for 807 KAR 5:001 Section 10(1)(a)9 above.

807 KAR 5:001 Section 10(4)(c)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(4)(c).

A. Since Big Rivers does not have more than twenty members, 807 KAR 5:001 Section 10(4)(c) is not applicable to Big Rivers' Application.

807 KAR 5:001 Section 10(4)(d)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(4)(d).

A. Big Rivers mailed its notice to its Member Cooperatives on February 28, 2011. See the response for 807 KAR 5:001 Section 10(1)(a)9 above.

807 KAR 5:001 Section 10(4)(f)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(4)(f).

A. As of March 1, 2011, Big Rivers' posted copies of the relevant notification at its offices located at 201 Third Street in Henderson, Kentucky 42420. Copies of those notices are also posted on Big Rivers' website at www.bigrivers.com.

807 KAR 5:001 Section 10(4)(g)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(4)(g).

A. Big Rivers, as noted above, has complied with the applicable notification requirements in 807 KAR 5:001 Section 10(4) and, therefore, is compliant with 807 KAR 5:051, Section 2.

807 KAR 5:001 Section 10(5)

Q. Please briefly describe Big Rivers' response to 807 KAR 5:001 Section 10(5).

A. Big Rivers will publish the necessary hearings notices as required by KRS 424.300 and 807 KAR 5:001 Section 10(5).

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

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

DIRECT TESTIMONY

OF

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

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

DIRECT TESTIMONY
OF
WILLIAM STEVEN SEELYE

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DIRECT TESTIMONY

OF
WILLIAM STEVEN SEELYE

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. By whom are you employed?

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

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Big Rive-rs Electric Corporation ("Big Rivers").

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

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company. From May 1979 until December 1990, I held various positions within the Rate Department of Louisville Gas and Electric Company. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left Louisville Gas and Electric

Company in July 1996 to form The Prime Group, LLC, with another former employee of the Company. Since then, we have performed cost of service studies, developed revenue requirements and designed rates for well over 100 investor-owned, cooperative and municipal utilities across North America. A more detailed description of my qualifications is included in Exhibit Seelye-1.

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

A. Yes. I have testified in over 60 regulatory proceedings in 12 different jurisdictions, including the Federal Energy Regulatory Commission ("FERC"), regarding revenue requirements, cost of service or rate design. A listing of my testimony in other proceedings is included in Exhibit Seelye-1.

Q. Have you developed rates for electric cooperatives?

A. Yes. I have developed rates for a number of generation and transmission cooperatives ("G&T cooperatives"), including Hoosier Energy, South Mississippi Electric Power Association, Big Rivers Electric Corporation, Southern Illinois Power Cooperative, Corn Belt Power Cooperative, Brazos Electric, and East Kentucky Power Cooperative, Inc. I have also supervised the preparation of cost of service studies and the development of rates for over 100 electric distribution cooperatives.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (i) support the cost of service study; (ii) describe the proposed allocation of the revenue increase to the rate classes; (iii) describe the rate design, new rates, and percentage increase by rate class; (iv) describe the proposed pro forma adjustment to the Smelter TIER Adjustment Charges; (v) support proposed changes to the Member Rate Stability Mechanism and Rural Economic Reserve; (vi) support the Non-Smelter Non-FAC PPA; (vii) support the Midwest Independent Transmission System Operator Inc. ("Midwest ISO") Attachment O; (viii) sponsor the temperature normalization adjustment; and (ix) support certain Filing Requirements from 807 KAR 5:001.

Q. Please summarize your testimony.

A. Big Rivers' proposed rates are designed to increase base rate revenues by $39,953,965, which is necessary to provide Big Rivers with sufficient margins to meet the financial requirements set forth in its debt agreements and to continue to provide reliable service to its customers. This increase in base rates is necessary so that Big Rivers can meet its Margins for Interest Ratio ("MFIR") requirement and maintain investment grade credit ratings, both as required by its debt covenants.

Big Rivers conducted a fully allocated embedded cost of service study to develop rates in this proceeding. Big Rivers has three major rate classifications – Rural Delivery Service ("Rurals"), Large Industrial Customer Rate ("Large Industrials"), and two aluminum smelters ("Smelters") served under special retail and wholesale contracts ("Smelter Agreements"). The cost of service study indicates that the rate of return for the Rurals is lower than the Large Industrials and the Smelters. Big Rivers is proposing to take steps in this proceeding to move the rates of return for the Rurals and Large Industrials closer together. Because the rates for the Smelters are contractually tied to the rate for the Large Industrials, any movement toward mitigating the differential in the rates of return must be accomplished through the apportionment of the revenue increase between the Rurals and Large Industrials. Therefore, Big Rivers is proposing rates that will eliminate some of the differential in the rate of return between the Rurals and the Large Industrials. Because the rates for the Smelters are tied to the rate for the Large Industrials, Big Rivers' proposal will also close the gap between the Rurals and the Smelters.

Big Rivers is also proposing a rate design change to the Rurals' rates. Particularly, Big Rivers is proposing to bill the Rurals on the basis of coincident peak demands rather than non-coincident peak demand. A demand charge billed on the basis of coincident peak demand will send a more accurate price signal to the Rurals. Under Big Rivers' proposed rates, the Large Industrials will continue to be billed on the basis of non-coincident peak demands.

Big Rivers is proposing to adjust the base purchased power cost used in the Non-FAC PPA. Specifically, Big Rivers is proposing to reduce the Non-FAC PPA from \$0.00175 per kWh to \$0.000874 per kWh. This revenue neutral "roll in" will result in a corresponding reduction in the energy charges for the three rate classifications. Also, Big Rivers is proposing a new rate mechanism (which will be called the "Non-Smelter Non-FAC PPA") that will allow it to amortize any balances in the Non-FAC PPA Regulatory Account for the Rurals and Large Industrials every 12 months rather than waiting until the next general rate case to amortize the balances.

The revenue adjustment sought by Big Rivers will eliminate 50 percent of the TIER Adjustment Charges billed to the Smelters on a pro forma basis, which is equivalent to moving the Smelters' TIER Adjustment Charge to the middle of the bandwidth. Positioning the Smelters in the middle of the bandwidth restores the purpose of the TIER Adjustment, which is to allow Big Rivers to draw extra revenue from the smelters if adverse conditions threaten Big Rivers' ability to achieve a 1.24 TIER between rate cases. This allows the contracts with the Smelters to function as envisioned when they were negotiated.

Additionally, Big Rivers is proposing to modify the Member Rate Stability Mechanism ("MRSM") and the Rural Economic Reserve ("RER") so that the two mechanisms operate more seamlessly. The MRSM was implemented for the purpose of distributing a $157 million Economic Reserve to the Rurals and the Large Industrials to offset any net billing impacts related to the FAC and Environmental Surcharge. The RER was ordered to be recorded as a regulatory liability of $60.9 million and used only as a credit against the rates of the Rurals once the Economic Reserve is depleted. Big Rivers is proposing modifications to these mechanisms so that there will not be any discontinuities in billings to the Rurals as a result of transitioning from the Economic Reserve to the RER.

Big Rivers is also proposing a temperature normalization adjustment. Big Rivers' adjustment meets the criteria that the Commission has established in prior Orders for approval of temperature normalization.

Big Rivers is also requesting authorization to implement Midwest ISO Attachment O transmission formula rate as set forth in Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Midwest ISO Tariff") for service to wholesale customers under the Midwest ISO Tariff.

Q. Do you have any exhibits to your testimony?

A. Yes. I have prepared or supervised the preparation of the following exhibits to my prepared testimony:

- Exhibit Seelye-1 – Qualifications of William Steven Seelye
- Exhibit Seelye-2 – Cost of Service Study - Functional Assignment and Classification
- Exhibit Seelye-3 – Cost of Service Study - Allocation
- Exhibit Seelye-4 – Reconciliation of Billing Determinants
- Exhibit Seelye-5 – Analysis of Non-FAC PPA
- Exhibit Seelye-6 – Summary of Revenue Increase
- Exhibit Seelye-7 – Non-Smelter Non-FAC PPA
- Exhibit Seelye-8 – Updated Midwest ISO Attachment O
- Exhibit Seelye-9 – FERC Order in Docket No. ER11-15-000
- Exhibit Seelye-10 – Temperature Normalization Adjustment

III. <u>FILING REQUIREMENTS</u>

Q. Have you reviewed the answers provided in Exhibits 1-47, which address Big Rivers' compliance with the historical period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of Exhibits 1-47 for which I am identified as the sponsoring witness as part of this Direct Testimony.

IV. CLASSES OF SERVICE

Q. Please describe the customer classes served by Big Rivers?

A. Big Rivers has three major rate classifications – (i) Rural Delivery Service, (ii) Large Industrial Customer Rate, and (iii) the Smelters. Rural Delivery Service is the rate schedule under which Big Rivers sells power to its three distribution cooperative member systems for resale to their own rural members. Therefore, Big Rivers sells power at wholesale under Rural Delivery Service to its three member systems – Jackson Purchase Energy Corporation ("Jackson Purchase"), Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corp. ("Meade County") – who in turn sell the power at retail to their members. The vast majority of the power delivered under Rural Delivery Service is distributed to residential customers. The Large Industrial Customer Rate is used to provide power to 20 large industrial customers – 19 of which are served by Kenergy and one of which is served by Jackson Purchase.

The customers served under the Large Industrial Customer Rate range in size from 0.1 MW to 36.9 MW. Big Rivers also provides service to two large aluminum smelters under special contracts which were approved by the Commission in its Order dated March 6, 2009, in Case No. 2007-00455. The Smelter Agreements are with Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century"). The base demand for Alcan is 368 MW and the base demand for Century is 482 MW. The Base Rate under the Smelter Agreements is determined by applying the Large Industrial Customer Rate to a load with a 98 percent load factor, plus a $0.25 per MWh adder. Thus, contractually, any base rate increase to the Smelters in this proceeding will be determined by the demand and energy charges established for the Large Industrial Customer Rate.

Except to the extent that any rate increase in the Large Industrial Customer Rate affects the Base Rate in the Smelter Agreements, the other contractual provisions of the Smelter Agreements will be unaffected by the proposed rates in this proceeding. The Smelter Agreements, approved by the Commission in connection with the Unwind Proceeding, were carefully negotiated among the parties and fully recognize the risks and benefits associated with Big Rivers continuing to provide service to the Smelters and the risks and benefits of the Smelters continuing to receive service from Big Rivers.

Q. What is the kWh sales composition of the three classes of service?

A. During the test year, 68 percent of Big Rivers' total requirement sales were delivered to the Smelters, 23 percent of total requirement sales were delivered to the Rurals, and 9 percent of total requirement sales were delivered to the Large Industrials. Thus, the class comprising the two Smelters is the largest customer class served by Big Rivers.

V. <u>COST OF SERVICE STUDY</u>

Q. Did you prepare a cost of service study for Big Rivers based on financial and operating results for the test year?

A. Yes. I supervised the preparation of a fully allocated, embedded cost of service study based on pro forma operating results for the 12 months ended October 31, 2010. The cost of service study corresponds to the pro forma financial exhibits included in Exhibit Wolfram-2. The objective in performing the cost of service study is to determine the rate of return on rate base that Big Rivers is earning from each rate class, which provides an indication as to whether Big Rivers' service rates reflect the cost of providing service.

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

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

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

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

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

A. Yes.

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

A. The functional groups identified in the cost of service study are Production and Transmission costs.

Q. How were costs classified as energy related or demand related in the cost of service study?

A. Classification provides a method of identifying the appropriate cost driver for each functionally assigned cost so that the service characteristics that give rise to the cost can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation or transmission equipment necessary to meet customers' needs.

Production plant costs are classified as demand-related in the cost of service study. Production operation and maintenance expenses are classified using the FERC Predominance Methodology. Under the *FERC Predominance Methodology*, production operation and maintenance accounts that are predominately fixed, i.e. expenses that the FERC has determined to be predominately incurred independently of kilowatt hour levels of output, are classified as demand-related. Production operation and maintenance accounts that are predominately variable, i.e., expenses that the FERC has determined to vary predominately with output (kWh), are considered to be energy related. The predominance methodology has been accepted in FERC proceedings for over 25 years and is a standard methodology for classifying production operation and maintenance expenses. For example, see *Public Service Company of New Mexico,* 10 FERC ¶ 63,020 (1980), *Illinois Power Company*, 11 FERC ¶ 63,040 (1980), *Delmarva Power & Light Company,* 17 FERC ¶ 63,044 (1981), and *Ohio Edison Company,* 24 FERC ¶ 63,068 (1983). The Predominance Methodology has also been used in the cost of service studies submitted by Kentucky Utilities and Louisville Gas and Electric Company in Case Nos. 2003-00433, 2003-00434, 2008-000251, 2008-00252, 2009-00548, and 2009-00549 and by East Kentucky Electric Power Cooperative in Case No. 2008-00409.

Transmission plant costs and transmission operation and maintenance expenses are classified as demand-related in the cost of service study. This is the same methodology used to classify these costs in the Midwest ISO's FERC-approved Midwest ISO Tariff under which transmission service by Big Rivers is provided.

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

A. Yes. Exhibit Seelye-2 shows the results of the first two steps of the cost of service study – functional assignment and classification.

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

A. In the cost of service model used in this study, Big Rivers' test-year costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and cost classifications (demand and energy). Therefore, in the portion of the model included in Exhibit Seelye-2, Big Rivers' accounting costs are functionally assigned and classified using the explicitly determined functional vectors identified in the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on page 14.

Internally generated functional vectors are utilized throughout the study to functionally assign costs either on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on page 14 of Exhibit Seelye-2. An example of this process is the use of total operation and maintenance expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign and classify these costs on the same basis. (See Exhibit Seelye-2, page 2 for the functional assignment of cash working capital on the basis of OMLPP shown on page 14.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Functional Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

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

The results of the class allocation step of the cost of service study are included in Exhibit Seelye-3. The costs shown in the column labeled "Total System" in Exhibit Seelye-3 were carried forward *from* the functionally assigned and classified costs shown in Exhibit Seelye-2. The column labeled "Ref" in Exhibit Seelye-3 provides a reference to the results included in Exhibit Seelye-2.

Q. What rate classes are identified in the cost of service study?

A. In the cost of service study, all costs and revenues are fully allocated to the following three rate classes – Rurals, Large Industrials, and Smelters.

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

A. Production and transmission demand-related costs are allocated using a 12CP methodology. With the 12CP methodology, all demand-related costs are allocated on the basis of the average demand for each rate class at the time of Big Rivers' system peak. For purposes of identifying the hour during which Big Rivers' system peak occurs, Big Rivers' adjusted net local load was determined in the following manner: (i) the *actual demand* for the Smelters and for a customer with cogeneration capability ("Cogen Customer") was subtracted from Big Rivers' total net local load; and then (ii) the Smelters' Base Demand *and* the lesser of (a) the Cogen Customer's actual demand or (b) the Cogen Customer's requirement load, as set forth in the contract with the customer, was added back. The Rural's and Industrial Customer's demand at the time of the Big Rivers maximum monthly adjusted net local load was used to calculate the 12CP allocation factor. Again, the demand for the Cogen Customer, which is included in the Large Industrial class, was determined as the lesser of the Cogen Customer's actual demand or the Cogen Customer's requirement load. The Smelters' Base Demand was used to determine the 12CP demands for the Smelters.

Energy-related costs are allocated on the basis of annual kWh sales to each customer class. Because energy is delivered to each rate class at transmission voltages, it was not necessary to adjust kWh sales for losses.

Q. How were the margins from off-system sales allocated in the cost of service study?

A. Section 4.13.1 of the Smelter Agreements provides that the Smelters receive billing credits reflecting the net proceeds from certain off-system sales. During the test year, the Smelters received $28,015,863 in billing credits pursuant to Section 4.13.1 of the Smelter Agreements. In the cost of service study, these off-system sales are directly assigned to the Smelters pursuant to Section 4.13.1 and exactly match the credits that the Smelters receive. The margins on all other off-system sales are allocated to the Rurals and Large Industrials on the basis of the 12CP allocator.

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

A. The following table summarizes the rates of return for each customer class from the cost of service study. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro forma adjustments described in Mr. Wolfram's testimony.

Class Rates of Return	
Customer Class	**Actual Adjusted Rate of Return**
Rurals	-1.43%
Large Industrials	1.69%
Smelters	3.19%
Total System	**1.64%**

Determination of the actual adjusted rates of return is detailed in Exhibit Seelye-3, page 11.

It should be emphasized that the adjusted rates of return shown in the above table reflect all pro forma revenue and expense adjustments proposed by Big Rivers in its Application in this proceeding. Consequently, the rates of return reflect adjustments in revenues and expenses to eliminate the effect of the fuel adjustment clause, environmental surcharge, and the Non-FAC PPA, which are addressed by separate stand-alone rate mechanisms. In addition, as will be discussed later in my testimony, the above rates of return also reflect an adjustment to eliminate 50 percent of the TIER Adjustment Charge revenues billed to the Smelters during the test year.

Q. Since the Smelter Base Rate is tied contractually to the Large Industrial base rates, why is the rate of return for the Smelters higher than the rate of return for the Large Industrials?

A. Under the Smelter Agreements, the Smelters agree to pay a number of charges that are not paid by the Large Industrials or Rurals. Particularly, the Smelters agree to pay TIER Adjustment Charges (Section 4.7.1), Surcharges (Section 4.11), and a Base Rate Adder of $0.25 per MWh (Section 1.1.20). These charges were the result of arms-length negotiations between the parties and were developed in recognition of the risks and benefits associated with Big Rivers providing service to the Smelters and the risks and benefits of the Smelters receiving service from Big Rivers. Big Rivers and the Smelters have agreed that they would not seek any change in the rate formula in the Smelter Agreements. In the cost of service study, the revenues associated with these charges were fully attributed to the Smelters, thus resulting in a higher rate of return for the Smelters.

VI. ALLOCATION OF THE INCREASE

Q. Please summarize how Big Rivers proposes to allocate the revenue increase to the classes of service?

A. Big Rivers relied on the results of the cost of service study to determine the allocation of the proposed revenue increase to the classes of service. Specifically, Big Rivers is proposing to allocate the revenue increase in a manner that is designed to narrow 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. Because the Base Rates for the Smelters are linked by contract to the Large Industrial Customer Rate, no explicit consideration was given to the rate of return shown in the cost of service study for the Smelters. Except for the effect of the TIER Adjustment Charges proposed for the Smelters, which will be discussed later in my testimony, the Smelters' Base Rates cannot be adjusted independently from the Large Industrial rates. Thus, other than the effect of modifying the level of TIER Adjustment Charges in test-year revenues, the only other "levers" or "variables" that can be used to collect additional base rate revenues are (i) to increase the base rates for the Rurals and (ii) to increase the base rates for Large Industrials. Any base rate increase to the Smelters is essentially a by-product of increasing the base rates to the Large Industrials.

Q. How is Big Rivers allocating the revenue increase in a manner that narrows the rates of return between the Rurals and the Large Industrials?

A. The proposed increase is designed to reduce the difference between the revenues collected from the Rurals and the cost of providing service to the Rurals. According to the cost of service study, there is currently a difference of approximately $11.1 million between the revenues collected from the Rurals and the actual cost of providing service to the Rurals. Under the proposed rates, there will be a difference of approximately $9.2 million between the revenues to be collected from the Rurals and the actual cost of providing service. Consequently, Big Rivers is proposing to move the rates for the Rurals $1.9 million closer to the actual cost of providing service.

Q. Is this approach to allocating the increase to the Rurals and the Large Industrials consistent with the principle of gradualism?

A. Yes. Although Big Rivers believes that is it is appropriate to take steps toward equalizing the rates of return between the Rurals and Large Industrials, Big Rivers must also consider the impact that taking overly aggressive steps toward leveling the rates of return would have on residential customers, which is the predominant type of customer served under the Rurals' cost of service classifications.

Q. What is the proposed base rate revenue increase for each rate class?

A. Big Rivers is proposing the following base rate revenue increases: an increase of $14,172,003 to the Rurals; an increase of $3,328,566 to the Large Industrials; and an increase of $22,553,396 to the Smelters. As will be demonstrated later, the Large Industrials and Smelters will experience a significantly lower percentage increase than the Rurals.

Q. What are the class rates of return adjusted to reflect the proposed revenue increases?

A. The following table shows the rates of return from the cost of service study on an adjusted basis with and without the proposed revenue increases:

Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Rate of Return with the Proposed Revenue Increases**
Rurals	-1.43%	2.51%
Large Industrials	1.69%	4.95%
Smelters	3.19%	6.36%
Total System	**1.64%**	**5.05%**

This table illustrates how the gap in the rate of return between the Rurals and the Large Industrials has been narrowed with Big Rivers' proposed allocation of the increase. Under Big Rivers' current rates, there is a 3.1 percentage point gap between the rate of return for the Rurals and the rate of return for the Large Industrials (|-1.43 - 1.69| =3.12 percentage points). After adjusting the rates of return to reflect the proposed revenue increase, the gap in the rates of return for the Rurals and Large Industrials is decreased to 2.44 percentage points (|2.51 - 4.95| = 2.44 percentage points). Therefore, Big Rivers' proposed allocation of the revenue increase will have reduced the rate of return gap between these two rate classes by approximately 22 percent.

VII. RATE DESIGN & IMPACT OF NEW RATES

Q. Have you prepared an exhibit showing the reconstruction of Big Rivers' test-year billing determinants?

A. Yes. The reconstruction of Big Rivers' billing determinants (revenue proof) is shown on Exhibit Seelye-4. As shown on this exhibit, when Big Rivers' current rates are applied to test-year actual billing determinants the resultant calculated revenues precisely match actual revenues during the test year.

Q. Is Big Rivers proposing any rate design changes to the Rurals' rates?

A. Yes. Big Rivers is proposing to bill the demand charge on the basis of Coincident Peak ("CP") demands rather than Non-Coincident Peak ("NCP") demands. Because production and transmission facilities are design to meet maximum aggregated loads on system, a CP rate design more accurately reflects cost causation on the Big Rivers system. The Rurals are currently billed on an NCP basis. Under Big Rivers' current NCP rate design, billing demands for the Rurals are determined on the basis of member demands measured at the time of each distribution member's maximum load during the month. Under the proposed CP rate design, billing demands for the Rurals will be determined on the basis of the distribution member's load measured at the time of Big Rivers' maximum adjusted net local load during the month, determined on a 30-minute clock-hour basis. In establishing the 30-minute interval during which the maximum load occurs, Big Rivers' adjusted net local load will be determined in the following manner: (i) the *actual demand* for the Smelters and for the Cogen Customer will be subtracted from Big Rivers' total net local load; and then (ii) the Smelters' Base Demand *and* the lesser of (a) the Cogen Customer's actual demand or (b) the Cogen

Customer's requirement load, as set forth in the contract with the customer, will be added back. This is the same procedure that was used to determine the CP demands in the cost of service study.

Q. What are the proposed charges for the Rurals?

A. Big Rivers is proposing to increase the demand charge from $7.370 per kW per month (billed on the basis of NCP demand) to $10.1890 per kW per month (billed on the basis of CP demand). Except for the roll-in of the Non-FAC PPA, which will be discussed below, Big Rivers is not proposing to modify the energy charge, which is currently $0.02040 per kWh. The cost of service study indicates that a cost-based energy charge would be $0.015761 per kWh. Lowering the energy charge to $0.015761 per kWh to correspond to the energy cost derived from the cost of service study would require an even larger increase in the demand charge than what is being proposed by Big Rivers. Decreasing the energy charge and increasing the demand charge by a larger amount would result in a larger percentage increase to the member system with the lowest average load factor and the highest concentration of residential load.

Q. Is Big Rivers proposing any rate design changes to the Large Industrial rates?

A. No. The Large Industrials are currently billed on an NCP basis. Big Rivers is not proposing to adopt a CP rate design for the Large Industrials. The individual contracts with the Large Industrial customers include minimum contract demands which were determined on the basis of NCP demands. Adopting a CP demand charge would likely require the development of new contracts with the Large Industrial customers and would also result in a larger increase to the Smelters, which cannot be supported considering the higher rate of return for the Smelters as indicated by the cost of service study. Although Big Rivers is not proposing any changes in the basic structure of the base rates, it should be noted that Big Rivers is proposing modifications to the MRSM

Q. What are the proposed charges for the Large Industrials?

A. Big Rivers is proposing to increase the demand charge from $10.1500 per kW per month to $10.8975 per kW per month and to increase the energy charge from $0.013715 per kWh to $0.015761 per kWh. As mentioned earlier, the cost of service study indicates that a cost-based energy charge would be $0.015761 per kWh.

Q. How were the Base Rates for the Smelters determined?

A. As described earlier, the Base Rate rates for the Smelters are derived by applying the Large Industrial Rate to a load with a 98 percent load factor, plus a $0.25 per MWh adder. At a 98 percent load factor, the demand component the Large Industrial Rate stated as an energy charge is equal to $0.015233 per kWh, which is determined by dividing the proposed Large Industrial demand charge ($10.8975 per kW) by 715.4 hours (730 hrs x 98 percent = 715.4 hours) ($10.8975/kW ÷ 715.4 hours = $0.015233/kWh). The energy charge from the proposed Large Industrial rate ($0.015761 per kWh) and the $0.25 per MWh adder ($0.000250 per kWh) is then added to the demand component ($0.015233 per kWh) to obtain the proposed Base Energy Charge for the Smelters of $0.031244 per kWh ($0.015761/kWh + $0.000250/kWh + $0.015233/kWh = $0.031244/kWh). After reflecting the proposed reduction in the Purchase Power Base for the Non-FAC PPA (as discussed below), the proposed Base Energy Charge for the Smelters is $0.030368 per kWh ($0.031244/kWh - $0.000876/kWh = $0.030368/kWh).

Q. Have any other adjustments been made that affect pro forma revenue for the Smelters?

A. Yes. Big Rivers is proposing to reduce the TIER Adjustment Charges billed under Section 4.7.1 of the Smelter Agreements by 50 percent. During the test year, Big Rivers billed the maximum amount allowed under Section 4.7.1 of the Smelter Agreements. The TIER Adjustment Charges to the Smelters were $14,229,306 during the test year. Big Rivers is proposing a pro forma adjustment to reduce the TIER Adjustment Charges billed to the Smelters to $7,114,653. Reducing the TIER Adjustment Charges by 50 percent would restore $7.1 million to the TIER Adjustment bandwidth which would then be available, as contemplated in the Smelter Agreements, to meet any differences that could arise between pro forma operating results developed in this proceeding and actual operating results that occur once the rates go into effect. If the actual operating results turn out exactly like the pro forma operating results developed for the test-year in this proceeding, then Big Rivers would bill $7.1 million in TIER Adjustment Charges to the Smelters. However, if Big Rivers' expenses are higher or revenues are lower than what was developed in the test year, but with everything else equal, then Big Rivers would be able to charge the Smelters up to an additional $7.1 million in TIER Adjustment Charges. On the other hand, if Big Rivers' expenses are lower or revenues are higher than what was developed in the test year, but again with everything else equal, then Big Rivers would lower the $7.1 million TIER Adjustment Charges billed to the Smelters.

Q. Why isn't Big Rivers proposing to eliminate all of the TIER Adjustment Charges during the test year?

A. Setting the TIER Adjustment Charge at the middle of the bandwidth (from $0 to $14.2 million) strikes an equitable balance in capping the additional exposure to the Smelters, for purposes of this Application, at $7.1 million (i.e., $14.2 million total exposure less $7.1 million pro forma exposure = $7.1 million additional exposure). Furthermore, setting the TIER Adjustment Charge at the middle of the bandwidth also strikes a reasonable balance between lower TIER Adjustment Charges and higher base rates. Lowering the TIER Adjustment Charges to $0 would increase base rates to all customers, including the Smelters by an additional $7.1 million above what is being proposed by Big Rivers. Reducing the TIER Adjustment Charges by 50 percent thus represents a balanced proposal.

Q. Is setting the TIER Adjustment Charge within the bandwidth consistent with the financial projections filed with the Commission in Unwind proceeding and provided to the financial rating agencies?

A. Yes. The TIER Adjustment Charges were generally projected to be within the bandwidth in the financial forecasts submitted in the Unwind Proceeding, Case No. 2007-00455, and in the financial projections provided to Standard and Poor's, Fitch, and Moody's in December 2008 and in March 2009 to obtain credit ratings in connection with the Unwind. In Exhibit No. 79 submitted by Big Rivers in Case No. 2007-00455, Big Rivers provided a financial forecast going out to 2023. Beginning in 2011, the Smelters were shown to be between the top and the bottom of the bandwidth in all but two years. As a percentage of the maximum level, the lowest TIER Adjustment Charge was in 2017, which was a year that incorporated the full effect of a rate increase occurring in 2016. In 2017, the TIER Adjustment Charge was shown to be $0.54 per MWh, whereas the maximum TIER Adjustment Charge is $3.55 per MWh. Thus, during 2017 the TIER Adjustment Charge is only 13 percent of the maximum level, suggesting that the TIER Adjustment Charge assumed in the general rate case was somewhere in the middle or toward the bottom of the bandwidth.

Q. Has a pro forma adjustment been made to reduce the TIER Adjustment Charges by $7,114,653?

A. Yes. In Reference Schedule 2.22 of Exhibit Wolfram-2, an adjustment is made to reduce test-year revenues to $7,114,653.

Q. Is Big Rivers proposing to modify the Purchased Power Base that is used in the Non-FAC PPA?

A. Yes. In its Order in Case No. 2007-00455 dated March 6, 2009, the Commission approved the Non-FAC PPA provision of the Smelter Agreements, which provides for a monthly calculation of a Non-FAC PPA factor that is charged or credited monthly in the Smelter bills. The Commission also approved the establishment of a Regulatory Account Charge, through which the Non-FAC PPA charges and credits applicable to non-Smelter customers will be recorded and then be amortized over a period of time after review in a general rate case. Big Rivers is proposing to lower the Purchased Power Base used in the Non-FAC PPA to reflect a more representative level of purchased power expenses on a going forward basis. Unlike the Fuel Adjustment Clause, there is not a two-year review process wherein changes to the base are considered; therefore, Big Rivers is proposing to change the base in this proceeding. However, it should be pointed out that changing the base represents a revenue neutral change and thus will not change the level of costs ultimately to be billed to customers.

The Non-FAC PPA factor ("PPA") is determined by subtracting the Purchased Power Base (PP(b)/S(b)) (currently $0.00175 per kWh) from the quotient of the monthly purchased power expenses PP(m) and the monthly sales S(m), as follows:

$$PPA = PP(m)/S(m) - \$0.00175.$$

Big Rivers is proposing to lower the Purchased Power Base from $0.00175 per kWh to $0.000874 per kWh. The proposed Purchased Power Base reflects the average purchased power costs PP(m)/S(m) for June 2010. Exhibit Seelye-5 shows the average purchased power costs for the test year. The reason that Big Rivers is proposing to use the average cost for June to re-establish a new Purchased Power Base is that the cost for June 2010 of $0.000874 per kWh is reasonably close to the average cost of $0.00082 per kWh for the test year, which can be seen in Exhibit Seelye-5. Determining the Base on the basis of the cost for a single month is consistent with the Commission's normal practice of determining the FAC Base on the basis of fuel costs for a particular month.

Q. What rate adjustments are made to reflect the new Purchased Power Base?

A. As already mentioned, the Purchased Power Base in the Non-FAC PPA will be decreased from $0.001750 per kWh to $0.000874 per kWh, which corresponds to a reduction of $0.000876 per kWh. In order to effectuate this change, a corresponding reduction must also be made to the otherwise applicable energy charges for the Rurals, Large Industrials and Smelters. Reducing the energy charges established in each of the three rate schedules will fully offset the billing effect of the corresponding reduction in the Purchased Power Base in the Non-FAC PPA.

Q. Will the Rurals and Large Industrials experience an immediate reduction in billings as a result of lower the Purchased Power Base in the Non-FAC PPA?

A. Yes. Unlike the Non-FAC PPA for the Smelters, the charges and credits under the Non-FAC PPA for the Rurals and Large Industrials ("Non-Smelters") are captured in a Regulatory Account which is amortized at a later date. As a result of lowering the Purchased Power Base, the Rurals and Large Industrials will see an immediate reduction in the energy charges of their rates. However, the off-setting effect that lowering the Purchased Power Base will have on the amounts charged or credited to the Regulatory Account will not be reflected in the bills to the Non-Smelters until one year later, when the Regulatory Account will be amortized under Big Rivers' proposed Non-Smelter Non-FAC PPA. As will be discussed in greater detail below, Big Rivers is proposing to amortize the Non-FAC PPA Regulatory Account for the Non-Smelters over a 12-month period beginning after charges or credits have been accumulated in the Regulatory Account up through June of each year. Because the Regulatory Account will not be amortized until one year after changing the Purchased Power Base reflected in base rates, the Rurals and Large Industrials will experience an immediate reduction in their bills as a result of lowering the Purchased Power Base, but will not experience the offsetting effect on the Regulatory Account until one year later. While changing the Purchased Power Base *is revenue neutral in the long run,* the impact of lowering the Purchased Power Base will be seen by the Rurals and Large Industrials as a rate reduction during the first year. *However, it should be emphasized that the effect is purely short term and should not be considered permanent.*

Q. Will the Smelters experience an immediate reduction in billings as a result of lowering the Purchased Power Base in the Non-FAC PPA?

A. Yes. Because there will be a one-month delay between the implementation of new Base Rates for the Smelters in this proceeding and the effect on the Non-FAC PPA factor as a result of changing the Purchase Power Base, the Smelters will realize a one-month billing reduction as a result of lowering the Purchased Power Base.

Q. Have you prepared an exhibit showing the impact of the proposed rates on pro forma revenue?

A. Yes. Exhibit Seelye-6 shows the increase in revenue by rate class from applying Big Rivers' proposed rates to pro forma billing determinants. In this analysis, the billing determinants and revenue reflect the following pro forma adjustments: (i) the adjustment to reflect current industrial customers, (ii) the adjustment to reflect normal temperatures, and (iii) reduction of 50 percent of the TIER adjustment charges to the Smelters. The adjustment to reflect current industrial customers and the adjustment to reflect normal temperatures are discussed in Mr. Wolfram's testimony. The adjustment to reflect 50 percent of the TIER adjustment charges has already been discussed. The increases are summarized on page 1 of Exhibit Seelye-6, with the detailed calculations shown on pages 2 and 3. The detailed calculations provided on pages 2 and 3 show the proposed rates both with and without the proposed adjustment to the Purchased Power Base in the Non-FAC PPA. The increases in base rates and the percentage increases are the same in either scenario. By adjusting the Purchased Power Base, base rate revenues are decreased and Non-FAC PPA revenues (for the Smelters) or accruals (for the non-Smelters) are decreased.

Amortizing the Non-FAC PPA Regulatory Account will result in an estimated annual reduction to the Non-Smelters of $3,236,077 through the application of the proposed Non-Smelter Non-FAC PPA, which will be discussed below. The following table summarizes the percentage increase by rate class, considering only the impact of the increase in base rates, elimination of 50 percent of the TIER Adjustment Charges, and the estimated annual reduction due to the amortization of the Non-FAC PPA Regulatory Account:

Impact of Proposed Revenue Increase

Including Base Rate Increase, Elimination of TIER Adjustment Charges, and Amortizing the Estimated Non-FAC PPA Regulatory Account

Customer Class	Current Revenue	Proposed Revenue Increase*	Percentage Increase
Rurals	$ 110,513,089	$ 11,831,935	10.71%
Large Industrials	$ 39,260,372	$ 2,332,557	5.94%
Smelters	$ 282,391,841	$ 15,438,743	5.47%
Total System	**$ 432,165,302**	**$ 29,603,235**	**6.85%**

However, lowering the Purchased Power Base will result in an immediate, *but ultimately revenue neutral*, reduction of $2,959,159, based on test-year results. The following table summarizes the net percentage increase by rate class, accounting for the increase in base rates, elimination of 50 percent of the Smelter TIER Adjustment Charges, the amortization of the Non-FAC PPA Regulatory Account through the proposed Non-Smelter Non-FAC PPA (which will be discussed below), <u>*and*</u> the immediate, *but ultimately revenue neutral*, reduction in billings that the Rurals and Large Industrials will experience as a result of lowering the Purchased Power Base in the Non-FAC PPA:

Net Impact of Proposed Revenue Increase

Including Base Rate Increase, Elimination of TIER Adjustment Charges, Amortizing the Estimated Non-FAC PPA Regulatory Account, and the Short-Term Effect of Lowering the Purchased Power Base in the Non-Smelter Non-FAC PPA

Customer Class	Current Revenue	Proposed Revenue Increase*	Percentage Increase
Rurals	$ 110,513,089	$ 9,686,481	8.77%
Large Industrials	$ 39,260,372	$ 1,518,852	3.87%
Smelters	$ 282,391,841	$ 15,438,743	5.47%
Total System	**$ 432,165,302**	**$ 26,644,076**	**6.17%**

Q. Is the percentage increase for the Rurals representative of the impact that Big Rivers' rate increase will have on the Members' retail rates to their members?

A. No. The average impact on the Members' retail rates will result in a lower overall percentage increase than what is being proposed by Big Rivers for the wholesale rates. Because the Members' retail rates also include the cost of providing distribution service to their members, the percentage impact of Big Rivers' rate increase will be diluted at the retail level. Big Rivers estimates that its proposed increase, without considering the temporary effect of the roll-in of the Non-FAC PPA, will result in an increase of approximately \$6.70 per month to a retail residential customer with a monthly consumption of 1,300 kWh, assuming a distribution losses of 6 percent (\$11,831,935 / 2,428,480,630 kWh x 1300 kWh ÷ [1.00 - 0.06] ≈ \$6.70). (See Exhibit Seelye-6, page 2.) The average net bill for a residential customer on the Big Rivers system with a 1,300 kWh monthly usage is approximately \$98.50 per month. Therefore, Big Rivers' proposed rates will result in an increase of approximately 6.8 percent for a typical residential customer with a monthly usage of 1,300 kWh (\$6.70 ÷ \$98.50 = 6.8%). Obviously, this is a very rough estimate of the impact of Big Rivers' proposed increase on retail rates. The actual retail percentage increase will vary by individual distribution cooperative member depending upon its individual sales characteristics. Big Rivers' Members will be making their own separate filings to reflect Big Rivers' increase in their rates, and in those filings the increases will be quantified with greater specificity, by retail rate classification.

Q. In a separate proceeding, Big Rivers is proposing to "roll in" amounts currently billed through its Fuel Adjustment Clause ("FAC") into base rates. Have the rates shown in Exhibit Seelye-6 been adjusted to give effect to the roll-in?

A. No. In Case No. 2010-00495, Big Rivers is proposing to increase the base cost used in the FAC by $0.010212 per kWh and increase the energy charges by a corresponding amount. However, at this point in time, the Commission has not approved the FAC roll-in; therefore, the effect of a roll-in was not reflected in the rates shown in Exhibit Seelye-6 or in the tariffs filed with the Application. However, any FAC roll-in authorized in Case No. 2010-00495 must be incorporated in the final rates implemented in this proceeding. Big Rivers therefore commits to incorporate any roll-in of the FAC authorized in Case No. 2010-00495 in the compliance rates filed with the Commission pursuant to an order in this proceeding.

VIII. MEMBER RATE STABILITY MECHANISM AND RURAL ECONOMIC RESERVE

Q. Is Big Rivers proposing changes to the Member Rate Stability Mechanism and the Rural Economic Reserve?

A. Yes. Big Rivers is proposing changes to the MRSM to specify how the mechanism will operate if it remains in place beyond the original 48 months that were anticipated when the mechanism was originally established. Current projections indicate that the Economic Reserve is likely to last beyond the 48 month horizon originally anticipated. Big Rivers is also proposing changes to the RER so that it will operate seamlessly with the expiration of the MRSM.

Q. What is the purpose of the MRSM?

A. An Economic Reserve of $157 million was originally established to offset the impact of the FAC and Environmental Surcharge on the Non-Smelters after taking into account the credits received from the Unwind Surcredit and the Rebate Adjustment. The MRSM draws on the Economic Reserve to offset the monthly impacts of the FAC and Environmental Surcharge on the Members' non-Smelter bills, net of the credits received under the Unwind Surcredit and Rebate Adjustment. An Expense Mitigation Factor was included in the MRSM to alter the speed at which the Economic Reserve was to be drawn down and thereby "feather" the effect of anticipated FAC and Environmental Surcharge Expenses on the Non-Smelter rates until the Economic Reserve is exhausted and the full amounts of FAC and Environmental Surcharge are applied without credit. (See page 4 of Supplemental Direct Testimony of William Steven Seelye submitted in Case Nos. 2007-00455 and 2007-00460.)

Q. Why does the MRSM need to be modified?

A. In the tariff sheets for the MRSM filed in the Unwind proceeding, Expense Mitigation Factors were specified for the first 48 months following the effective date of the tariff. The following EMFs are currently set forth in the tariff:

I. $0.000 per kWh for the first twelve (12) months following the effective date of this tariff;

II. $0.002 per kWh for months 13 through 24 following the effective date of this tariff;

III. $0.004 per kWh for months 25 through 36 following the effective date of this tariff; and

IV. $0.006 per kWh for months 37 through 48 following the effective date of this tariff;

Because the Economic Reserve is not expected to be depleted until after the first 48 months, the MRSM needs to be modified to specify what the EMF will be after the first 48 months following the original effective date of the tariff.

Q. How is Big Rivers proposing to change the MRSM?

A. Big Rivers is proposing to add two additional EMFs that will extend beyond the first 48 months of the mechanism. Specifically, Big Rivers is proposing to add a fifth EMF equal to $0.007 per kWh and applicable for months 49 through 60 following the effective date of the tariff and a sixth EMF equal to $0.009 per kWh that would be applicable thereafter.

Q. Why is Big Rivers proposing to increase the EMF by $0.001 per kWh between the fourth and fifth periods rather than by $0.002 per kWh as in all of the other incremental changes?

A. Big Rivers is proposing to increase the EMF by only $0.001 per kWh between the fourth and fifth periods in order to account for the expiration of the amortization of the current Non-Smelter Non-FAC regulatory liability. The amortization of the Non-Smelter Non-FAC PPA regulatory liability through the proposed Non-Smelter Non-FAC PPA adjustment clause will expire in approximately August 2013. Expiration of the amortization will result in the elimination of a credit of approximately $0.001 per kWh. In order to offset the elimination of the credit, Big Rivers is proposing to reduce the normal $0.002 per kWh increment by $0.001 per kWh in the fifth EMF.

Q. What is the purpose of the RER?

A. In its Order in Case No. 2007-00455 dated March 6, 2009, the Commission required Big Rivers to commit to establish a Rural Economic Reserve of not less than $60.9 million to be used exclusively to credit the bills rendered to the Rurals over a period of 24 months commencing with the depletion of all funds in the Economic Reserve.

Q. How is Big Rivers proposing to change the RER?

A. Big Rivers is proposing to change the RER so that it operates seamlessly with the MRSM. Specifically, Big Rivers is proposing that the RER operate in the same manner as the MRSM, except applicable only to the Rurals, thereby offsetting the impact of the FAC and Environmental Surcharge on the Rurals after taking into account the credits received from the Unwind Surcredit and the Rebate Adjustment. Thus, once the Economic Reserve is exhausted by the application of the MRSM, the EMFs identified in the MRSM will be adopted by the RER so that there will not be a discontinuity in the amounts credited to the Rurals between the two mechanisms. Therefore, the EMF schedule set forth in the MRSM will continue to be used in the determination of the amounts credited under the RER. For example, if the Economic Reserve expires in the 52nd month following the effective date of the tariff, then the RER will be billed for the first time in the 53rd month using an EMF of $0.007 per kWh. In this example, the EMF of $0.007 per kWh would then continue for another eight months (i.e., for the 53rd through the 60th month following the effective date of the MRSM). In the 61st month, the EMF would then transition to $0.009 per kWh and remain at that level until the Rural Economic Reserve is exhausted.

IX. NON-FAC PPA ADJUSTMENT CLAUSE FOR THE NON-SMELTERS

Q. Please describe the Non-FAC PPA mechanisms currently used by Big Rivers.

A. Big Rivers has in place two different Non-FAC PPA mechanisms – (i) a Non-FAC PPA for the Smelters, which provides for a monthly calculation of a Non-FAC PPA factor that is charged or credited monthly in the Smelter bills; and (ii) a Regulatory Account Charge, through which the Non-FAC PPA charges or credits applicable to the Non-

Smelters are recorded in a deferred asset or deferred liability account to be amortized at a later date.

Q. How much has been accrued in the Non-FAC PPA Regulatory Account for the Non-Smelters?

A. As of October 31, 2010, a regulatory liability balance of $4,364,060 had been accrued for the Non-Smelter Non-FAC PPA. This means that as of October 31, 2010, the Rurals and Large Industrials are owed $4,364,060.

Q. How does Big Rivers propose to return the Non-FAC PPA Regulatory Account Charges to the Rurals and Large Industrials?

A. Big Rivers is proposing to establish a mechanism that would amortize the Non-FAC PPA Regulatory Account balance every 12 months, instead of waiting to amortize the Non-FAC PPA Regulatory Account as part of a general rate case. In the bills for September service each year, Big Rivers will establish a credit (or charge) to return (or collect) the Non-FAC PPA Regulatory Liability (or Asset) balance as of June 30 over the upcoming 12 month period, except for the initial implementation of this mechanism in 2011, which Big Rivers is proposing to return the liability as of June 30, 2010, over 24 months.

Under this mechanism, beginning with bills for September 2011, Big Rivers will establish a per kWh credit which would be designed to return the Non-FAC PPA Regulatory Liability balance as of June 30, 2011, over 24 months beginning with the September 2011 bills. If Big Rivers' PPA expenses continue at the current level, then we estimate that the Non-FAC PPA Regulatory Liability will be approximately $6.5 million by June 30, 2011. This balance would then be returned to the Rurals and Large Industrials through the application of a per kWh credit that would be calculated by dividing the $6.5 million balance by the estimated kWh sales to the Rurals and Large Industrials for the upcoming 24 months. If the estimated sales to the Rurals and Large Industrials are 6,750,000,000 kWh for the 24 month period beginning September 2011, then the Rurals and Large Industrials would receive a credit of $0.000963 per kWh related to the $6.5 million balance. The $0.000963 per kWh credit would remain in place for 24 months. After the factor has been in place for 24 months, any remaining under- or over-recovery will be transferred to the Non-FAC PPA Regulatory Account for the subsequent period.

Then with bills for September 2012, Big Rivers will establish a per kWh credit or charge which would be designed to return or recover the Non-Smelter Non-FAC PPA Regulatory Liability or Asset balance as of June 30, 2012, over 12 months beginning with September 2012 bills. The credit or charge for the June 30, 2011, regulatory account balance would remain in effect for 12 months. Because this 12 month period would overlap with the initial implementation of the mechanism in 2011, two factors would be in effect – the first related to the June 30, 2011, balance and the second related to the June 30, 2012, balance. In subsequent 12 month periods (i.e., beginning with bills for service in September 2013), only one factor would be in effect at any given time.

Q. Is Big Rivers proposing a new rate schedule describing the proposed Non-FAC PPA mechanism described above?

A. Yes. The rate schedule is called "Non-Smelter Non-FAC PPA" and appears on sheet numbers 59 through 63 of Big Rivers' proposed tariff. See Exhibit 7 of the Application. For ease of reference, a copy of the rate schedule is also included in Exhibit Seelye-7.

Q. Is Big Rivers proposing to make a pro forma adjustment in this proceeding to reflect the amortization of the Non-FAC PPA Regulatory Liability?

A. No. Instead of including a pro forma adjustment to amortize the Regulatory Liability and return the balance through base rates, Big Rivers is proposing to return the liability through the mechanism described above. Big Rivers' Non-Smelter rate classes will receive their credits beginning in the same month (in the September 2011 bills) as they would otherwise receive those benefits if they were reflected in base rates by including a pro forma adjustment in this proceeding to amortize the Non-Smelter Non-FAC PPA regulatory liability.

Q. What are the advantages of establishing the proposed mechanism compared to including the amortization of the regulatory liability as part of base rates?

A. Establishing a mechanism to clear the Regulatory Account balance every 12 months is much more orderly than waiting until subsequent rate cases to clear any balances. If the amortization of the Regulatory Account is included in base rates, an assumption must be made regarding the amortization period, which may not accurately reflect the actual period between rate cases. Setting up a credit or charge to clear the Regulatory Account every 12 months, as proposed by Big Rivers, ensures that any Non-FAC PPA Regulatory Account Charges are dealt with in a timely manner, rather than waiting until a rate case is filed.

Furthermore, amortizing the Regulatory Account through a separate Non-Smelter Non-FAC PPA adjustment clause *that is only applicable to the Non-Smelters* helps ensure that the Smelters do not receive any additional credits or charges associated with the amortization of the Non-Smelter Non-FAC PPA Regulatory Account. As mentioned earlier, the Smelter Agreements include Non-FAC PPA provisions that provide automatic monthly rate adjustments to the Smelters to reflect changes in purchased power costs. Consequently, none of the Non-Smelter Non-FAC PPA regulatory liability should be distributed to the Smelters. Unless somewhat complicated precautions are undertaken, including the amortization of the Non-Smelter Non-FAC PPA regulatory liability as a pro forma adjustment to operating results in this proceeding would effectively assign a portion of the Non-Smelter Non-FAC PPA regulatory liability to the Smelters, thus resulting a double counting of the credits. Because the Smelter's Base Energy Charge is contractually linked to the Large Industrials' base rate, returning the regulatory liability through base rates (i.e., through a pro forma adjustment to amortize the regulatory liability) in this proceeding would inappropriately result in an additional credit to the Smelters. Establishing a separate Non-Smelter Non-FAC PPA adjustment clause that is only applicable to the Non-Smelters is in my opinion the most straightforward way to amortize the Regulatory Account to the Non-Smelters.

X. MIDWEST ISO ATTACHMENT O TRANSMISSION FORMULA RATE

Q. Did the Commission approve Big Rivers' membership in the Midwest ISO?

A. Yes. The Commission approved the transfer of operational control of Big Rivers' transmission facilities to the Midwest ISO in Case No. 2010-00043, *In the Matter of Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc.* in its Order dated November 1, 2010 ("Midwest ISO Order").

Q. Please describe Midwest ISO Attachment O.

A. Midwest ISO Attachment O is used to determine the transmission service rates under the Midwest ISO Tariff. Attachment O, which is updated annually, is used to determine the annual transmission revenue requirements for each transmission owner in Midwest ISO. Revenue requirements are determined based on plant and expense data from the utility's FERC Form 1, RUS Form 12, or EIA Form 412, as applicable, and include the following components: (i) operating expenses, including operation and maintenance expenses, taxes other than income tax, and depreciation expenses, (ii) return on transmission net investment grossed up for income taxes, less (ii) transmission revenue credits. For illustrative purposes, a copy of an updated Attachment O for the test year is shown in Exhibit Seelye-8. As can be seen from the Attachment O for Big Rivers, net revenue requirements are shown on page 1, line 7. Operating Expenses consist of (a) total operation and maintenance expenses shown on page 3, line 8, (b) depreciation expenses shown on page 3, line 12, and (c) taxes other than income taxes shown on page 3, line 20. The return on transmission net investment is shown on page 3, line 28, and the income tax gross up is shown on page 3, line 22. Transmission net plant is shown on page 2, line 18, and adjustments to rate base are shown on line 24. Please note that the updated Attachment O calculation shown in Exhibit Seelye-8 is being provided solely to illustrate how the FERC-approved transmission formula rate will be calculated. The actual updated Attachment O will not be implemented until the Commission authorizes the use of the Attachment O formula rate in this proceeding and will be developed based on cost information for the 2010 calendar year, in accordance with the normal cycle for the historical-cost formula rates used by the members of the Midwest ISO.

Q. Is the Midwest ISO Attachment O an FERC-approved rate schedule?

A. Yes, it is. The revenue requirement set forth in Midwest ISO's Attachment O for Big Rivers is applicable to all loads sinking in Big Rivers' transmission pricing zone, including retail load. Therefore, in the strictest sense, Schedule 9 - Network Integration Service of Midwest ISO's Midwest ISO Tariff is the "filed rate" applicable to loads that sink in Big Rivers' control area.

Q. Has the FERC approved an interim Attachment O for Big Rivers?

A. Yes. On October 14, 2010, the Midwest ISO and Big Rivers filed revisions to the Midwest ISO tariff to include Big Rivers' company-specific Attachment O template with the FERC in Docket No. ER11-15-000. Big Rivers and the Midwest ISO sought approval for deviations from the Midwest ISO's Attachment O formula rate template, on an interim basis, to use the rates that were currently contained in Big Rivers' OATT, which this Commission had approved, until such time as Big Rivers obtained approval from this Commission to use the Midwest ISO Attachment O formula rate. Big Rivers advised the FERC that Big Rivers anticipated a filing with this Commission to adjust the transmission rates to be effective no later than January 1, 2012, and noted that at that time Big Rivers would seek approval from this Commission to adjust its transmission rates to utilize the Midwest ISO Attachment O formula rate. Big Rivers sought to utilize the existing OATT rates until such time as this Commission approved an adjustment to Big Rivers' transmission rates to utilize the Midwest ISO Attachment O formula rate. For convenience, a copy of that Order is attached as Exhibit Seelye-9.

Q. Did the FERC issue an order in Docket No. ER11-15-000?

A. Yes. FERC conditionally accepted for filing Big Rivers' Attachment O formula rate, to be effective December 1, 2010, through and including December 31, 2011. FERC noted in its order dated November 24, 2010, that this acceptance with an end date of December 31, 2011 does not foreclose the Midwest ISO and Big Rivers from making a filing at an earlier date to adopt an appropriate formula rate for Big Rivers.

Q. Is Big Rivers requesting authorization to adjust its transmission rates to use the Midwest ISO Attachment O on an ongoing basis?

A. Yes. Big Rivers is requesting to use the Midwest ISO Attachment O and to update the inputs used in the transmission formula rate on an annual basis.

Q. If the Commission approves the use of the Midwest ISO Attachment O formula rate, do you anticipate that a revised Attachment O rate will become effective prior to December 31, 2011?

A. Yes. In the spring of each year, Transmission-Owning members of Midwest ISO ordinarily provide Attachment O data for the previous calendar year to Midwest ISO. Midwest ISO then utilizes the Attachment O data for the previous calendar year when updating its transmission rates to become effective June 1st of the current year. On this schedule, in the spring of 2011 Big Rivers will compile Attachment O data for calendar year 2010 and provide it to Midwest ISO; Midwest ISO will incorporate the 2010 Attachment O data for rates that become effective June 1, 2011. Thus, the Big Rivers Attachment O formula rate, if authorized by this Commission to be used by Big Rivers, would go into effect when the retail rates approved by the Commission in this proceeding become effective, pre-empting the transmission rates that are presently approved on an interim basis only until December 31, 2011.

Q. Please describe the transmission costs included in Midwest ISO's FERC-approved Attachment O formula rate?

A. Schedule 7 - Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service, Schedule 8 - Non-Firm Point-to-Point Transmission Service, and Schedule 9 - Network Integration Service of Midwest ISO's Midwest ISO Tariff are assessed for any loads sinking in a transmission owner's transmission pricing zone. The charges collected under these schedules are based on the rate formula contained in Attachment

O of the Midwest ISO Tariff. The rate formula corresponds to a revenue requirement calculation that is performed annually by each Midwest ISO transmission owner. The revenue requirements, including operating expenses and a return on transmission net investment grossed up for income taxes, less transmission revenues (revenue credits) collected pursuant to the Schedule 7, 8, and 9 of the Midwest ISO Tariff, are allocated to the transmission owner.

Q. Will the adoption of the Attachment O transmission formula rate affect base rates charged to Big Rivers' members?

A. No.

XI. TEMPERATURE NORMALIZATION ADJUSTMENT

Q. Is Big Rivers proposing a temperature normalization adjustment for electric operations in this proceeding?

A. Yes.

Q. What is the purpose of making such an adjustment in a rate case?

A. In a general rate case, service rates are set at a level that will provide the utility a reasonable opportunity to recover its costs on a going-forward basis. The underlying principle is that when rates go into effect as a result of a general rate case, those rates will represent a level of revenue that will allow the utility to recover its reasonably incurred costs on a going-forward basis. This principle holds regardless of whether a projected test year or a historical test year is used to set rates. When rates are based on a historical test year, pro forma adjustments are made to test-year operating results so that revenues and expenses will be representative on a going-forward basis. This is the principle behind adjusting certain test-year operating results to reflect a going-forward level of expenses and revenues for things such as annualizing revenues and expenses for new customers or annualizing certain expenses (e.g., depreciation expense and wages and benefits expense) to reflect the full amount on a going forward basis. In this proceeding, the Company has made a number of other normalization adjustments to help ensure that the historical test year will be representative of costs and revenues on a going-forward basis. Only normalization adjustments that are supported by a *sound statistical methodology* and apply *clear and objective measures* are used to adjust test year results.

Q. Why is it appropriate to make a temperature normalization adjustment in this proceeding?

A. Electric utility sales vary with temperature. As temperatures rise during the summer, more electric energy is used by customers to operate the compressors on their air-conditioners. Likewise, as temperatures go down in the winter, more electric energy is used by customers to operate electric furnaces and other space-heating appliances. Consequently, for any day during the summer or winter, Big Rivers' electric sales will increase and decrease as a result of changes in temperature. Without a temperature normalization adjustment, there can be no assurance that the test year level of expenses, and therefore, the proposed amount of revenue will be representative on a going forward basis.

Q. Should revenues and expenses reflect a *range* of cooling and heating degree days representative of normal conditions?

A. Yes. What is considered normal can be represented in a number of statistically valid ways. One methodology – the mean-value approach – is to represent normal degree days by calculating a 30-year average. Another methodology would be to establish a statistically determined range centered on the mean-value degree days.

From a statistical perspective, a 30-year mean, or average, would represent a measure of the *expected value* for heating degree days. For a normally-distributed probability density function, the expected value of a random variable is equal to the mean value. Or stated more rigorously, the maximum likelihood estimator for a normally distributed random variable is equal to the sample mean value. (For example, see Robert V. Hogg and Allen T. Craig, *Introduction to Mathematical Statistics*, Third Edition, 1975, at 257.) Therefore, the 30-year average heating degree days are considered to be representative of a going-forward level of heating degree days for purposes of determining test-year levels of revenues and sales.

This is a standard approach for normalizing natural gas revenues and expenses, and is also used in other jurisdictions to normalize electric revenues and expenses. Although it has accepted the mean-value methodology for calculating gas temperature normalization adjustments for natural gas utilities for many years, the Commission has expressed concerns about using the mean-value approach for electric temperature normalization. In its Order in Louisville Gas and Electric's Case No. 10064, the Commission stated as follows:

> The Commission is of the opinion that there is adequate evidence to suggest that a range of temperatures and not a specific mean temperature is a more appropriate measure of normal temperatures. As long as the temperature falls within these bounds then it is inappropriate to adjust sales for temperature. However, if the

> temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound. (Order in Case No. 10064, dated July 1, 1988, at 39.)

Therefore, an alternative to the mean-value approach, one which was suggested by the Commission's Order in Case No. 10064 and is well-grounded by statistical theory, would be to determine a *range* of cooling and heating degrees days that would be considered normal. Instead of normal degree days being represented by a mean value, a bandwidth around the mean value could be established. Cooling degree days inside the bandwidth would then be considered normal, and cooling degree days outside the bandwidth – either high or low – would be considered abnormal or extraordinary, requiring a normalization adjustment to bring revenues and sales to within a normal range. A standard approach for establishing a *normal range* of a random variable is to determine a bandwidth of two standard deviations centered on the mean. The rationale for this approach is that for a normally-distributed (Gaussian) probability density function, the random variable will fall within a range between one standard deviation above and one standard deviation below the mean value 68 percent of the time. More important for our purposes is the fact that a random variable will only exceed the two standard deviation bandwidth 16 percent of the time. Assuming that cooling and heating degree days are normally distributed, which is a standard supposition well-grounded in empirical research, only 16 percent of the time would temperatures be expected to exceed one standard deviation above or below the mean.

Q. Which methodology did Big Rivers use for the Temperature Normalization Adjustment it is proposing in this case?

A. Big Rivers is proposing to use the banded methodology described above. Specifically, if heating and cooling degree days during a month are *within* plus or minus one standard deviation of the mean degree days for the month, then no adjustment would be made during that month. If heating or cooling degree days for a month are more than one standard deviation above the average for that month, then sales would be adjusted upward or downward to reflect the heating or cooling degree days at the top end of the range. In other words if the degree days are above the top end of the range, they are not adjusted to the *average* but only to *one standard deviation above* the average. Likewise if heating or cooling degree days for a month are more than one standard deviation below the average for that month, then sales would be adjusted downward or upward to reflect the heating or cooling degree days at the bottom end of the range.

This approach places constraints on the magnitude of the temperature normalization adjustment when compared with an adjustment based on the mean value. First, a constraint is placed on the magnitude of the total revenue and expense adjustment because monthly normalization adjustments would only be made during months when cooling or heating degree days fall outside a particularly wide range of degree days. Second, the methodology would only adjust sales to one of the two end points of the degree day range. Thus, this approach would certainly result in lower revenue and expense adjustments than adjusting to the mid-point of the degree-day range (the mean value).

The determination of Big Rivers proposed revenue and expense adjustments are shown in Exhibit Seelye-10. Page 1 of the exhibit shows the calculation of the revenue adjustment ($421,610), the expense adjustment ($295,293), and the net overall adjustment of ($126,318). Page 2 shows the calculation of the base fuel and variable cost per kWh used to determine the expense adjustment. Page 3 shows the determination of normalized sales and the kWh adjustment used to calculate the revenue and expenses adjustments. Page 3 of the exhibit also shows the cooling degree day and heating degree day bands for each month of the test year, based on one standard deviation above and one standard deviation below the 30 year average for the month. GDS Associates, Inc. constructed the analysis shown on page 3. GDS Associates, Inc. prepared the long term forecast for Big Rivers IRP filings. Because of its work in this area for Big Rivers, GDS Associates, Inc. had already compiled the data necessary to perform the analysis.

Q. Are there months during the year that would not be adjusted under this methodology?

A. Yes, for most months during the test year no adjustments are required. As can be seen from Exhibit Seelye-10 page 3, the only heating degree day adjustments that would be required are for the months of January and February. January is 32 degree days colder than the top of the range; and February is 74 degree days colder than the top of the range. The only cooling degree day adjustments that are necessary are for the months of June and August. June is 52 degree days hotter than the top end of the range; and August is 3 degree days hotter than the top end of the range.

Q. After the kWh sales adjustments were determined for each class, how was the revenue component of the adjustment calculated?

A. The revenue adjustment was calculated by applying the kWh adjustment for the Rurals to the applicable energy charge. No attempt was made to normalize the demand charges. The proposed temperature normalization procedure normalized kWh sales and not maximum individual demands. Had demands been normalized, the revenue adjustment would have been larger without materially changing the expense adjustment.

Q. How was the expense component of the adjustment determined?

A. The expense component of the temperature normalization adjustment was calculated by applying the kWh sales adjustment to the variable expenses per kWh during the test year. Variable expenses were determined using the FERC predominance methodology that was used in the Company's embedded cost of service study.

Q. Has the Commission ever considered an electric temperature normalization adjustment in other proceedings?

A. Yes. Electric temperature normalization adjustments were considered in Kentucky Utilities Case No. 98-474 and in Case No. 8284, Case No. 8616, Case No. 8924, Case No. 10064, and Case No. 98-426, which were LG&E rate proceedings. In each of these proceedings, the Commission denied the adjustment, noting that the companies had failed to adequately support the adjustment. The Commission however continued to endorse the concept of normalization and expressed a willingness to consider temperature adjustments in future rate proceedings. (See Commission's Orders in Cases 8284, page 9, 8616, page 15, 98-426, page 73, and Case No. 98-474, at page 70.)

In Case Nos. 98-474 and 98-426, the Commission expressed concern about the use of 20-year average degree days rather than a 30-year average, noting that "previous electric weather normalization adjustments proposed in the LG&E rate cases were based on a 30-year average. The 30-year average is typically used in gas weather normalization adjustments." (*Id.*, at 74.)

In Case No. 10064, the Commission expressed concern that LG&E did not construct a "confidence interval" for temperature adjustment purposes. On page 38 of the Order, the Commission observed that LG&E "adjusted each month's actual billing-cycle temperature-sensitive load to a mean determined temperature-sensitive load instead of to a temperature-sensitive load determined by the boundaries of a range of acceptable values constructed around the mean." (Order in Case No. 10064, dated July 1, 1998, at 38-39.) The Commission also expressed concern about the accuracy of the billing-cycle degree days used in the temperature normalization adjustment. Additionally, the Commission criticized LG&E's adjustment because it did not rely on a regression model to adjust test-year sales and only analyzed one variable. (*Id.*, at 42-43.)

The adjustments proposed by LG&E in Case Nos. 8284 and 8616 were developed without relying on any sort of statistical analysis. Temperature-sensitive load was estimated by first selecting a single month to calculate a base load level and then all sales during the summer months above that base load level were considered to be the temperature-sensitive load. The Commission rejected the methodologies proposed in those proceedings for obvious reasons.

Q. Do you believe that the Commission's concerns expressed in the previous rate cases where temperature normalization adjustments have been proposed are adequately addressed in this filing?

A. Yes. All previous concerns expressed by the Commission have been thoroughly and comprehensively addressed.

Q. How does this methodology address the Commissions past criticisms that any temperature normalization methodology should rely on statistical analysis?

A. Under the proposed methodology, GDS Associates, Inc. performed a statistical analysis to develop a bandwidth for each month and to determine the relationship of temperature to kWh sales to the Rurals.

Q. How does this methodology address the Commissions past criticisms that adjustments for temperature should not be made to a single mean value but to a range of acceptable values constructed around the mean?

A. Under the proposed methodology, GDS Associates, Inc. performed statistical analyses to develop a band width around the 30 year average number of degree days for each month. The band width was determined based on one standard deviation above and below the 30 year average.

Q. How does this methodology address the Commissions past criticisms that the relationship between temperature and kWh sales was not determined by using a regression analysis?

A. GDS Associates, Inc. performed a regression analysis to determine the relationship between temperature and kWh sales to the Rurals.

Q. How does this methodology address the Commissions past criticisms that normal temperature was based on a 20 year normal instead of a 30 year normal?

A. GDS Associates, Inc. used a 30 year normal to develop the bandwidths for each month of the year.

Q. Does the temperature normalization have the effect of decreasing test-year operating income and thus increasing the Company's proposed revenue increase?

A. Yes. Although the net effect of the adjustment is only $126,318, the temperature normalization adjustment decreases operating income and raises the Company's proposed rate increase in this filing.

Q. Do you recommend that this adjustment be made?

A. Yes. I believe that it is appropriate to make an electric temperature normalization adjustment.

XII. CONCLUSION

Q. Do you have any closing comments?

A. Yes. Big Rivers' proposed increase in base rates is necessary so that Big Rivers can meet its MFIR and maintain investment grade credit ratings, as required by its debt covenants. Big Rivers' proposed rates are designed to increase base rate revenues by $39,953,965, which is necessary for Big Rivers to meet the financial requirements set forth in its debt agreements and to continue to provide reliable service to its customers, as discussed in Mr. Blackburn's testimony. The proposed rates are designed to narrow the gap in the rates of return between the Rurals and Large Industrials.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit Seelye-1

Qualifications of
William Steven Seelye

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

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

Employment

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

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

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

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 150 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions Louisville Gas & Electric Co. (May 1979 to July 1996)	Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

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

Associations

Member of the Society for Industrial and Applied Mathematics

Expert Witness Testimony

Alabama:	Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.
Colorado:	Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.
FERC:	Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.
	Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.
	Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.
	Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.
	Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER11-2127-000 concerning transmission rates proposed by Terra-Gen Dixie Valley, LLC.

Submitted testimony in Docket No. ER11-2779 on behalf of Southern Illinois Power Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Submitted testimony in Docket No. ER11-2786 on behalf of Norris Electric Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

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

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

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

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

Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.

Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.

Submitted testimony in Case No. 2009-00548 on behalf of Kentucky Utilities Company and in Case No. 2009-00549 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2010-00116 on behalf of Delta Natural Gas Company concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

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

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

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

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

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

	Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.
	Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.
	Submitted direct testimony in Case No. Docket No. 10-06001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate cases.
Maryland	Submitted direct testimony in PSC Case No. 9234 on behalf of Southern Maryland Electric Cooperative regarding a class cost of service study.
Nova Scotia:	Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.
	Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.
	Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.
	Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.
	Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company's regarding a demand-side management cost recovery mechanism.
Virginia:	Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.
	Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00065 on behalf of Craig-Botetourt Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Exhibit Seelye-2

Cost of Service Study

Functional Assignment and Classification

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Plant in Service							
Intangible Plant	INTPLT	PT&D	$ 66,895	58,634	-	-	8,261
Production Plant	PPROD	F001	$ 1,686,796,955	1,686,796,955	-	-	-
Transmission Plant	PTRAN	F002	$ 237,659,206	-	-	-	237,659,206
Distribution Plant	PDIST	F003	$ -	-	-	-	-
Total Production & Transmission Plant	PT&D		1,924,456,160	1,686,796,955	-	-	237,659,206
General Plant	PGP	PT&D	$ 18,511,051	16,225,043	-	-	2,286,008
Total Plant in Service	TPIS		$ 1,943,034,107	$ 1,703,080,632	$ -	$ -	$ 239,953,475
Construction Work in Progress (CWIP)							
CWIP Production	CWIP1	PPROD	$ 22,411,274	22,411,274	-	-	-
CWIP Transmission	CWIP2	PTRAN	$ 7,475,859	-	-	-	7,475,859
CWIP Distribution Plant	CWIP3	PDIST	$ -	-	-	-	-
CWIP General Plant	CWIP4	PT&D	$ 16,915,005	14,826,100	-	-	2,088,905
Total Construction Work in Progress	TCWIP		$ 46,802,138	$ 37,237,374	$ -	$ -	$ 9,564,764
Total Utility Plant			$ 1,989,836,245	$ 1,740,318,006	$ -	$ -	$ 249,518,239

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Rate Base							
Total Utility Plant	TUP		$ 1,989,836,245	$ 1,740,318,006	$ -	$ -	$ 249,518,239
Less: Acummulated Provision for Depreciation							
Production	ADEPREPA	PPROD	$ 790,847,523	790,847,523	-	-	-
Transmission	ADEPRTP	PTRAN	$ 107,564,747	-	-	-	107,564,747
Distribution	ADEPRD11	PDIST	$ -	-	-	-	-
General & Common Plant	ADEPRD12	PT&D	$ 6,300,770	5,522,661	-	-	778,109
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -	-	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	$ -	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 904,713,040	$ 796,370,184	$ -	$ -	$ 108,342,855
Net Utility Plant	NTPLANT		$ 1,085,123,206	$ 943,947,822	$ -	$ -	$ 141,175,384
Working Capital							
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 28,050,527	13,844,414	11,969,243	-	2,236,870
Materials and Supplies	M&S	TPIS	$ 22,777,820	19,964,891	-	-	2,812,929
Fuel Stock	PREPAY	TPIS	$ 34,326,112	30,087,036	-	-	4,239,076
Total Working Capital	TWC		$ 85,154,459	$ 63,896,340	$ 11,969,243	$ -	$ 9,288,875
Net Rate Base	RB		$ 1,170,277,664	$ 1,007,844,162	$ 11,969,243	$ -	$ 150,464,259

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$ 4,974,566	4,974,566	-	-	-
501 FUEL	OM501	Energy	$ 200,919,367	-	200,919,367	-	-
502 STEAM EXPENSES	OM502	PROFIX	$ 34,453,882	34,453,882	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	$ 5,730,122	5,730,122	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$ 7,451,302	7,451,302	-	-	-
507 RENTS	OM507	PROFIX	$ -	-	-	-	-
509 ALLOWANCES	OM509	Energy	$ 429,682	-	429,682	-	-
Total Steam Power Operation Expenses			$ 253,958,921	$ 52,609,872	$ 201,349,049	$ -	$ -
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$ 3,631,867	-	3,631,867	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$ 3,346,806	3,346,806	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$ 30,113,309	-	30,113,309	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$ 6,251,804	-	6,251,804	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$ 877,364	877,364	-	-	-
Total Steam Power Generation Maintenance Expense			$ 44,221,151	$ 4,224,170	$ 39,996,981	$ -	$ -
Total Steam Power Generation Expense			$ 298,180,072	$ 56,834,042	$ 241,346,030	$ -	$ -

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$	-		-		-		-		-
547 FUEL	OM547	Energy	$	706,789		-		706,789		-		-
548 GENERATION EXPENSE	OM548	PROFIX	$	34,608		34,608		-		-		-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$	-		-		-		-		-
550 RENTS	OM550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses			$	741,396	$	34,608	$	706,789	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$	-		-		-		-		-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$	-		-		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$	625,088		625,088		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$	-		-		-		-		-
Total Other Power Generation Maintenance Expense			$	625,088	$	625,088	$	-	$	-	$	-
Total Other Power Generation Expense			$	1,366,485	$	659,696	$	706,789	$	-	$	-
Total Station Expense			$	299,546,557	$	57,493,738	$	242,052,819	$	-	$	-

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Other Power Supply Expenses												
555 PURCHASED POWER Energy	OM555	OMPP	$	19,466,790		-		19,466,790		-		-
555 PURCHASED POWER Demand	OMD555	OMPPD	$	4,210,045		4,210,045		-		-		-
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	$	58,293,374		13,175,571		45,117,803		-		-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$	-		-		-		-		-
555 BROKERAGE FEES	OMB555	OMPP	$	-		-		-		-		-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$	-		-		-		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$	909,422		909,422		-		-		-
557 OTHER EXPENSES	OM557	PROFIX	$	20,575,465		20,575,465		-		-		-
558 DUPLICATE CHARGES	OM558	Energy	$	-		-		-		-		-
Total Other Power Supply Expenses	TPP		$	103,455,096	$	38,870,503	$	64,584,593	$	-	$	-
Total Electric Power Generation Expenses			$	403,001,653	$	96,364,241	$	306,637,411	$	-	$	-
Transmission Expenses												
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$	876,815		-		-		-		876,815
561 LOAD DISPATCHING	OM561	LBTRAN	$	1,454,938		-		-		-		1,454,938
562 STATION EXPENSES	OM562	PTRAN	$	1,163,408		-		-		-		1,163,408
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$	1,090,014		-		-		-		1,090,014
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$	3,065,817		-		-		-		3,065,817
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$	475,381		-		-		-		475,381
567 RENTS	OM567	PTRAN	$	24,701		-		-		-		24,701
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$	647,227		-		-		-		647,227
569 STRUCTURES	OM569	PTRAN	$	26,913		-		-		-		26,913
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$	1,936,760		-		-		-		1,936,760
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$	2,876,462		-		-		-		2,876,462
572 UNDERGROUND LINES	OM572	PTRAN	$	-		-		-		-		-
573 MISC PLANT	OM573	PTRAN	$	97,880		-		-		-		97,880
Total Transmission Expenses			$	13,736,318	$	-	$	-	$	-	$	13,736,318
Distribution Operation Expense												
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$	-		-		-		-		-
581 LOAD DISPATCHING	OM581	PDIST	$	-		-		-		-		-
582 STATION EXPENSES	OM582	PDIST	$	-		-		-		-		-
583 OVERHEAD LINE EXPENSES	OM583	PDIST	$	-		-		-		-		-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	$	-		-		-		-		-
585 STREET LIGHTING EXPENSE	OM585	PDIST	$	-		-		-		-		-
586 METER EXPENSES	OM586	PDIST	$	-		-		-		-		-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	$	-		-		-		-		-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	$	-		-		-		-		-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	$	-		-		-		-		-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	$	-		-		-		-		-
589 RENTS	OM589	PDIST	$	-		-		-		-		-
Total Distribution Operation Expense	OMDO		$	-	$	-	$	-	$	-	$	-

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Operation and Maintenance Expenses (Continued)												
Distribution Maintenance Expense												
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$	-		-		-		-		-
591 STRUCTURES	OM591	PDIST	$	-		-		-		-		-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	$	-		-		-		-		-
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	$	-		-		-		-		-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	$	-		-		-		-		-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	$	-		-		-		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	$	-		-		-		-		-
597 MAINTENANCE OF METERS	OM597	PDIST	$	-		-		-		-		-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	$	-		-		-		-		-
Total Distribution Maintenance Expense	OMDM		$	-	$	-	$	-	$	-	$	-
Total Distribution Operation and Maintenance Expenses				-		-		-		-		-
Transmission and Distribution Expenses				13,736,318		-		-		-		13,736,318
Production, Transmission and Distribution Expenses	OMSUB		$	416,737,971	$	96,364,241	$	306,637,411	$	-	$	13,736,318
Customer Accounts Expense												
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$	-		-		-		-		-
902 METER READING EXPENSES	OM902	F025	$	-		-		-		-		-
903 RECORDS AND COLLECTION	OM903	F025	$	-		-		-		-		-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$	-		-		-		-		-
905 MISC CUST ACCOUNTS	OM903	F025	$	-		-		-		-		-
Total Customer Accounts Expense	OMCA		$	-	$	-	$	-	$	-	$	-
Customer Service Expense												
907 SUPERVISION	OM907	TUP	$	-		-		-		-		-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$	80,486		70,393		-		-		10,093
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$	-		-		-		-		-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$	-		-		-		-		-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$	-		-		-		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$	-		-		-		-		-
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$	-		-		-		-		-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$	-		-		-		-		-
913 ADVERTISING EXPENSES	OM913	TUP	$	488,103		426,897		-		-		61,206
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$	-		-		-		-		-
916 MISC SALES EXPENSE	OM916	TUP	$	-		-		-		-		-
Total Customer Service Expense	OMCS		$	568,589	$	497,290	$	-	$	-	$	71,299
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2			417,306,560		96,861,532		306,637,411		-		13,807,617

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$	14,315,713		6,663,061		5,595,161		-		2,057,491
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$	6,915,648		3,218,798		2,702,915		-		993,935
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$	-		-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$	3,954,189		1,840,425		1,545,457		-		568,306
924 PROPERTY INSURANCE	OM924	TUP	$	-		-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$	179,889		83,727		70,308		-		25,854
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$	169,663		78,967		66,311		-		24,384
927 FRANCHISE REQUIREMENTS	OM927	TUP	$	-		-		-		-		-
928 REGULATORY COMMISSION FEES	OM928	TUP	$	1,188,958		1,039,867		-		-		149,091
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$	-		-		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$	1,686,131		784,788		659,008		-		242,335
931 RENTS AND LEASES	OM931	PGP	$	1,933		1,694		-		-		239
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$	208,156		182,450		-		-		25,706
Total Administrative and General Expense	OMAG		$	28,620,280	$	13,893,778	$	10,639,160	$	-	$	4,087,342
Total Operation and Maintenance Expenses	TOM		$	445,926,840	$	110,755,309	$	317,276,572	$	-	$	17,894,959
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	224,404,213	$	110,755,309	$	95,753,945	$	-	$	17,894,959

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	4,967,667		4,967,667		-		-		-
501 FUEL	LB501	Energy	$	3,889,944		-		3,889,944		-		-
502 STEAM EXPENSES	LB502	PROFIX	$	9,023,322		9,023,322		-		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX	$	4,523,897		4,523,897		-		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	940,518		940,518		-		-		-
507 RENTS	LB507	PROFIX	$	-		-		-		-		-
509 ALLOWANCES	LB509	Energy	$	-		-		-		-		-
Total Steam Power Operation Expenses	LBSUB1		$	23,345,348	$	19,455,404	$	3,889,944	$	-	$	-
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	3,623,969		-		3,623,969		-		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	986,831		986,831		-		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	8,700,235		-		8,700,235		-		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	1,595,642		-		1,595,642		-		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	200,886		200,886		-		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	15,107,564	$	1,187,718	$	13,919,846	$	-	$	-
Total Steam Power Generation Expense			$	38,452,913	$	20,643,122	$	17,809,791	$	-	$	-

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$	-		-		-		-		-
547 FUEL	LB547	Energy	$	-		-		-		-		-
548 GENERATION EXPENSE	LB548	PROFIX	$	-		-		-		-		-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$	-		-		-		-		-
550 RENTS	LB550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses	LBSUB7		$	-	$	-	$	-	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	-		-		-		-		-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$	-		-		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$	89,555		89,555		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	-		-		-		-		-
Total Other Power Generation Maintenance Expense	LBSUB8		$	89,555	$	89,555	$	-	$	-	$	-
Total Other Power Generation Expense			$	89,555	$	89,555	$	-	$	-	$	-
Total Production Expense	LPREX		$	38,542,468	$	20,732,677	$	17,809,791	$	-	$	-

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Purchased Power							
555 PURCHASED POWER Energy	LB555	OMPP	$ -	-	-	-	-
555 PURCHASED POWER Demand	LBD555	OMPPD	$ -	-	-	-	-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$ -	-	-	-	-
555 BROKERAGE FEES	LBB555	OMPP	$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ -	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$ -	-	-	-	-
558 DUPLICATE CHARGES	LB558	Energy	$ -	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses							
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 835,977	-	-	-	835,977
561 LOAD DISPATCHING	LB561	PTRAN	$ 1,304,969	-	-	-	1,304,969
562 STATION EXPENSES	LB562	PTRAN	$ 598,382	-	-	-	598,382
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$ 236,393	-	-	-	236,393
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$ -	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$ 312,375	-	-	-	312,375
567 RENTS	LB567	PTRAN	$ -	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$ 644,925	-	-	-	644,925
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$ 318	-	-	-	318
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$ 1,433,304	-	-	-	1,433,304
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$ 1,067,766	-	-	-	1,067,766
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$ 46,439	-	-	-	46,439
Total Transmission Labor Expenses	LBTRAN		$ 6,480,848	$ -	$ -	$ -	$ 6,480,848
Distribution Operation Labor Expense							
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ -	-	-	-	-
581 LOAD DISPATCHING	LB581	PDIST	$ -	-	-	-	-
582 STATION EXPENSES	LB582	PDIST	$ -	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	PDIST	$ -	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	$ -	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	PDIST	$ -	-	-	-	-
586 METER EXPENSES	LB586	PDIST	$ -	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	$ -	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	$ -	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	$ -	-	-	-	-
589 RENTS	LB589	PDIST	$ -	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector		Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	$	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	$	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	$	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	$	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	$	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	$	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	PDIST	$	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	$	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$	-	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-	-	-	-	-
Transmission and Distribution Labor Expenses				6,480,848	-	-	-	6,480,848
Production, Transmission and Distribution Labor Expenses	LBSUB		$	45,023,316	$ 20,732,677	$ 17,809,791	$ -	$ 6,480,848
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	$	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	$	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	$	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$	-	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	LB907	TUP	$	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$	544,608	476,316	-	-	68,292
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	TUP	$	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$	544,608	$ 476,316	$ -	$ -	$ 68,292
Sub-Total Labor Exp	LBSUB9			45,567,924	21,208,994	17,809,791	-	6,549,140

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$	14,315,714		6,663,061		5,595,161		-		2,057,491
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$	-		-		-		-		-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$	-		-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$	-		-		-		-		-
924 PROPERTY INSURANCE	LB924	TUP	$	-		-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$	27,509		12,804		10,752		-		3,954
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$	17,136		7,976		6,698		-		2,463
928 REGULATORY COMMISSION FEES	LB928	TUP	$	-		-		-		-		-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$	-		-		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$	-		-		-		-		-
931 RENTS AND LEASES	LB931	PGP	$	-		-		-		-		-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$	74,927		65,674		-		-		9,253
Total Administrative and General Expense	LBAG		$	14,435,286	$	6,749,515	$	5,612,610	$	-	$	2,073,161
Total Operation and Maintenance Expenses	TLB		$	60,003,210	$	27,958,509	$	23,422,401	$	-	$	8,622,301
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	60,003,210	$	27,958,509	$	23,422,401	$	-	$	8,622,301

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
<u>Other Expenses</u>												
Depreciation Expenses												
Production	DEPRDP2	PPROD	$	28,815,395		28,815,395		-		-		-
Transmission	DEPRDP3	PTRAN	$	5,182,459		-		-		-		5,182,459
Transmission	DEPRDP4	PTRAN	$	-		-		-		-		-
Distribution	DEPRDP5	PDIST	$	-		-		-		-		-
General & Common Plant	DEPRDP6	PGP	$	238,155		208,744		-		-		29,411
Other Plant	DEPROTH	TPIS	$	-		-		-		-		-
Total Depreciation Expense	TDEPR		$	34,236,009		29,024,140		-		-		5,211,869
Accretion Expense												
Production	ACRTNP	F017	$	-		-		-		-		-
Transmission	ACRTNT	PTRAN	$	-		-		-		-		-
Distribution	ACRTND	PDIST	$	-		-		-		-		-
Total Accretion Expense	TACRTN		$	-	$	-	$	-	$	-	$	-
Property Taxes & Other	PTAX	TUP	$	(94,563)		(82,705)		-		-		(11,858)
Amortization of Investment Tax Credit	OTAX	TUP	$	-		-		-		-		-
Other Expenses	OT	TUP	$	(365,864)		(319,986)		-		-		(45,878)
Interest	INTLTD	TUP	$	47,622,710		41,650,995		-		-		5,971,715
Other Deductions	DEDUCT	TUP	$	109,257		95,557		-		-		13,700
Total Other Expenses	TOE		$	81,507,549	$	70,368,000	$	-	$	-	$	11,139,549
Total Cost of Service (O&M + Other Expenses)			$	527,434,389	$	181,123,310	$	317,276,572	$	-	$	29,034,508

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Functional Vectors							
Production Plant	F001		1.000000	1.000000	0.000000	0.000000	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.000000	0.000000	0.000000	1.000000
Production Plant	F017		1.000000	0.000000	1.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	1.000000	0.000000	0.000000
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000
Distribution Operation Labor	F023		-	-	-	-	-
Distribution Maintenance Labor	F024		-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	1.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	1.000000
Purchased Power Energy	OMPP		1.000000	0.000000	1.000000	0.000000	0.000000
Purchased Power Demand	OMPPD		1.000000	1.000000	0.000000	0.000000	0.000000
Purchased Power BREC Share of HMP&L Station Two	OMPPH		58,293,374	13,175,571	45,117,803	0.000000	0.000000
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors							
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.876506	-	-	0.123494
Total Transmission Plant		PTRAN	1.000000	-	-	-	1.000000
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.493553	0.426703	-	0.079744
Total Plant in Service		TPIS	1.000000	0.876506	-	-	0.123494
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.465950	0.390352	-	0.143697
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.232111	0.734801	-	0.033087
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.833374	0.166626	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.078617	0.921383	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.465437	0.390841	-	0.143723
Total General Plant		PGP	1.000000	0.876506	-	-	0.123494
Total Production Plant		PPROD	1.000000	1.000000	-	-	-
Total Intangible Plant		INTPLT	1.000000	0.876506	-	-	0.123494

Exhibit Seelye-3

Cost of Service Study

Class Allocation

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
Plant in Service										
Power Production Plant										
Production Demand	TPIS	PLPDMD	$	524,448,481	$	144,392,793	$	1,034,239,358	$	1,703,080,632
Production Energy	TPIS	PLPENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TPIS	PLPSTM	$	-	$	-	$	-	$	-
Total Power Production Plant		PLPT	$	524,448,481	$	144,392,793	$	1,034,239,358	$	1,703,080,632
Transmission Plant	TPIS	PLTRN	$	73,891,531	$	20,344,047	$	145,717,897	$	239,953,475
Distribution Substation	TPIS	PLDST	$	-	$	-	$	-	$	-
Distribution Other	TPIS	PLDMC	$	-	$	-	$	-	$	-
Total		PLT	$	598,340,013	$	164,736,840	$	1,179,957,254	$	1,943,034,107

BIG RIVERS ELECTRIC CORPORATION
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12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
Net Utility Plant										
Power Production Plant										
Production Demand	NTPLANT	NTPDMD	$	290,680,307	$	80,031,010	$	573,236,505	$	943,947,822
Production Energy	NTPLANT	NTPENG	$	-	$	-	$	-	$	-
Production - Steam Direct	NTPLANT	NTPSTM	$	-	$	-	$	-	$	-
Total Power Production Plant		NTPT	$	290,680,307	$	80,031,010	$	573,236,505	$	943,947,822
Transmission Plant	NTPLANT	NTTRN	$	43,473,700	$	11,969,315	$	85,732,370	$	141,175,384
Distribution Substation	NTPLANT	NTDST	$	-	$	-	$	-	$	-
Distribution Other	NTPLANT	NTDMC	$	-	$	-	$	-	$	-
Total		NTPLT	$	334,154,007	$	92,000,324	$	658,968,874	$	1,085,123,206

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
Net Cost Rate Base										
Power Production Plant										
Production Demand	RB	RBPDMD	$	310,356,615	$	85,448,352	$	612,039,195	$	1,007,844,162
Production Energy	RB	RBPENG	$	2,794,152	$	1,059,737	$	8,115,354	$	11,969,243
Production - Steam Direct	RB	RBPSTM	$	-	$	-	$	-	$	-
Total Power Production Plant		RBPT	$	313,150,767	$	86,508,089	$	620,154,549	$	1,019,813,405
Transmission Plant	RB	RBTRN	$	46,334,126	$	12,756,856	$	91,373,277	$	150,464,259
Distribution Substation	RB	RBDST	$	-	$	-	$	-	$	-
Distribution Other	RB	RBDMC	$	-	$	-	$	-	$	-
Total		RBPLT	$	359,484,893	$	99,264,945	$	711,527,826	$	1,170,277,664

BIG RIVERS ELECTRIC CORPORATION
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12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
<u>Operation and Maintenance Expenses</u>										
Power Production Plant										
Production Demand	TOM	OMPDMD	$	34,106,109	$	9,390,200	$	67,259,000	$	110,755,309
Production Demand Reallocation of Purchased Power			$	3,187,500	$	877,592	$	(4,065,092)	$	-
Production Energy	TOM	OMPENG	$	74,066,421	$	28,091,138	$	215,119,013	$	317,276,572
Production - Steam Direct	TOM	OMPSTM	$	-	$	-	$	-	$	-
Total Power Production Plant		OMPT	$	111,360,030	$	38,358,931	$	278,312,921	$	428,031,881
Transmission Plant	TOM	OMTRN	$	5,510,593	$	1,517,194	$	10,867,172	$	17,894,959
Distribution Substation	TOM	OMDST	$	-	$	-	$	-	$	-
Distribution Other	TOM	OMDMC	$	-	$	-	$	-	$	-
Total		OMPLT	$	116,870,623	$	39,876,124	$	289,180,093	$	445,926,840

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
Labor Expenses										
Power Production Plant										
Production Demand	TLB	LBPDMD	$	8,609,573	$	2,370,415	$	16,978,521	$	27,958,509
Production Energy	TLB	LBPENG	$	5,467,827	$	2,073,780	$	15,880,793	$	23,422,401
Production - Steam Direct	TLB	LBPSTM	$	-	$	-	$	-	$	-
Total Power Production Plant		LBPT	$	14,077,400	$	4,444,195	$	32,859,314	$	51,380,909
Transmission Plant	TLB	LBTRN	$	2,655,161	$	731,027	$	5,236,113	$	8,622,301
Distribution Substation	TLB	LBDST	$	-	$	-	$	-	$	-
Distribution Other	TLB	LBDMC	$	-	$	-	$	-	$	-
Total		LBPLT	$	16,732,561	$	5,175,222	$	38,095,427	$	60,003,210

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
Depreciation Expenses										
Power Production Plant										
Production Demand	TDEPR	DPPDMD	$	8,937,725	$	2,460,762	$	17,625,653	$	29,024,140
Production Energy	TDEPR	DPPENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	$	-	$	-	$	-	$	-
Total Power Production Plant		DPPT	$	8,937,725	$	2,460,762	$	17,625,653	$	29,024,140
Transmission Plant	TDEPR	DPTRN	$	1,604,949	$	441,879	$	3,165,041	$	5,211,869
Distribution Substation	TDEPR	DPDST	$	-	$	-	$	-	$	-
Distribution Other	TDEPR	DPDMC	$	-	$	-	$	-	$	-
Total		DPPLT	$	10,542,673	$	2,902,642	$	20,790,694	$	34,236,009

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
Property and Other Taxes										
Power Production Plant										
Production Demand	PTAX	PRPDMD	$	(25,468)	$	(7,012)	$	(50,225)	$	(82,705)
Production Energy	PTAX	PRPENG	$	-	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	$	-	$	-	$	-	$	-
Total Power Production Plant		PRPT	$	(25,468)	$	(7,012)	$	(50,225)	$	(82,705)
Transmission Plant	PTAX	PRTRN	$	(3,652)	$	(1,005)	$	(7,201)	$	(11,858)
Distribution Substation	PTAX	PRDST	$	-	$	-	$	-	$	-
Distribution Other	PTAX	PRDMC	$	-	$	-	$	-	$	-
Total		PRPLT	$	(29,120)	$	(8,017)	$	(57,426)	$	(94,563)

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
Interest Expenses										
Power Production Plant										
Production Demand	INTLTD	INPDMD	$	12,826,052	$	3,531,309	$	25,293,634	$	41,650,995
Production Energy	INTLTD	INPENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	$	-	$	-	$	-	$	-
Total Power Production Plant		INPT	$	12,826,052	$	3,531,309	$	25,293,634	$	41,650,995
Transmission Plant	INTLTD	INTRN	$	1,838,936	$	506,302	$	3,626,477	$	5,971,715
Distribution Substation	INTLTD	INDST	$	-	$	-	$	-	$	-
Distribution Other	INTLTD	INDMC	$	-	$	-	$	-	$	-
Total		INPLT	$	14,664,988	$	4,037,610	$	28,920,111	$	47,622,710

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
<u>Cost of Service Summary -- Unadjusted</u>						
Operating Revenues						
Sales to Members		REVUC	$ 110,934,700	$ 39,110,620	$ 282,406,135	$ 432,451,455
Off System Sales Revenue			$ 12,699,303	$ 4,615,318	$ 59,229,055	$ 76,543,676
Income from Leased Property Net		OTHREV	$ 45,976	$ 12,696	$ 91,001	$ 149,673
Other Operating Revenue & Income		OTHREV	$ 4,232,543	$ 1,168,737	$ 8,377,466	$ 13,778,745
Total Operating Revenues		TOR	$ 127,912,522	$ 44,907,371	$ 350,103,657	$ 522,923,549
Operating Expenses						
Operation and Maintenance Expenses			$ 116,870,623	$ 39,876,124	$ 289,180,093	$ 445,926,840
Depreciation and Amortization Expenses			$ 10,542,673	$ 2,902,642	$ 20,790,694	$ 34,236,009
Property and Other Taxes			$ (29,120)	$ (8,017)	$ (57,426)	$ (94,563)
Total Operating Expenses		TOE	$ 127,384,177	$ 42,770,749	$ 309,913,361	$ 480,068,286
Utility Operating Margin			$ 528,345	$ 2,136,622	$ 40,190,296	$ 42,855,263
Non-Operating Items						
Interest Income			$ -	$ -	$ -	$ -
Other Non-Operating Income			$ -	$ -	$ -	$ -
Other Credits			$ -	$ -	$ -	$ -
Interest on Long Term Debt			$ -	$ -	$ -	$ -
Other Interest Expense			$ -	$ -	$ -	$ -
Other Deductions			$ -	$ -	$ -	$ -
Total Non-Operating Items			$ -	$ -	$ -	$ -
Net Utility Operating Margin		TOM	$ 528,345	$ 2,136,622	$ 40,190,296	$ 42,855,263
Net Cost Rate Base			$ 359,484,893	$ 99,264,945	$ 711,527,826	$ 1,170,277,664

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma						
Operating Revenues						
Total Operating Revenue			$ 127,912,522	$ 44,907,371	$ 350,103,657	$ 522,923,549
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		$ (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		$ (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		$ -	$ -	$ (7,128,947)	$ (7,128,947)
Total Pro-Forma Operating Revenue			$ 99,720,079	$ 33,424,364	$ 262,052,077	$ 395,196,520

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma						
Operating Expenses						
Operation and Maintenance Expenses			$ 116,870,623	$ 39,876,124	$ 289,180,093	$ 445,926,840
Depreciation and Amortization Expenses			$ 10,542,673	$ 2,902,642	$ 20,790,694	$ 34,236,009
Property and Other Taxes			$ (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		$ (25,685,949)	$ (9,722,081)	$ (74,632,493)	$ (110,040,523)
To eliminate Environmental Surcharge expenses	2.03		$ (5,462,944)	$ (2,081,425)	$ (15,923,422)	$ (23,467,791)
To reflect weather normalized sales volumes	2.04		$ (295,293)	$ -	$ -	$ (295,293)
To eliminate Non-FAC PPA expenses	2.05		$ 2,858,740	$ 1,084,350	$ 8,072,083	$ 12,015,173
To reflect annualized depreciation expenses	2.06		$ 1,925,448	$ 530,120	$ 3,797,082	$ 6,252,651
To reflect increases in labor and labor-related costs	2.07		$ 174,259	$ 53,897	$ 396,739	$ 624,894
To reflect current interest on construction (CWIP)	2.08		$ 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		$ 1,743,155	$ 479,931	$ 3,437,592	$ 5,660,678
To reflect levelized production expenses	2.11		$ 839,745	$ 231,201	$ 1,656,019	$ 2,726,965
To reflect going forward Information Technology support services	2.12		$ 89,756	$ 24,784	$ 177,654	$ 292,194
To reflect amortizaton of rate case expenses	2.13		$ 86,538	$ 23,896	$ 171,285	$ 281,719
To reflect MISO related expenses	2.14		$ 1,667,501	$ 459,102	$ 3,288,398	$ 5,415,000
To annualize interest on long-term debt	2.15		$ 21,628	$ 5,972	$ 42,808	$ 70,408
To reflect leased property income (Soaper Building Rent)	2.16		$ (35,797)	$ (11,072)	$ (81,500)	$ (128,368)
To adjust for costs related to LEM Dispatch	2.17		$ (288,484)	$ (79,426)	$ (568,905)	$ (936,815)
To adjust for costs related to APM	2.18		$ 63,156	$ 17,388	$ 124,546	$ 205,090
To reflect going forward level of Outside Services	2.25		$ (725,000)	$ (275,000)	$ -	$ (1,000,000)
To eliminate costs for SFPC membership	2.20		$ (55,530)	$ (15,334)	$ (109,911)	$ (180,775)
To adjust for MISO Case-related expenses	2.21		$ (237,459)	$ (65,378)	$ (468,281)	$ (771,118)
To reflect commitment to Energy Efficiency Programs	2.26		$ 725,000	$ 275,000	$ -	$ 1,000,000
To eliminate promo advertising, lobbying, donation and econ dev	2.23		$ (130,114)	$ (45,872)	$ (331,230)	$ (507,216)
To reflect going forward level of income taxes	2.24		$ 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	$ 104,877,738	$ 31,744,245	$ 239,386,220	$ 376,008,202
Utility Operating Margins -- Pro-Forma			$ (5,157,658)	$ 1,680,119	$ 22,665,857	$ 19,188,318
Non-Operating Items			$ -	$ -	$ -	-
Total Non-Operating Items			$ -	$ -	$ -	-
Net Utility Operating Margin			$ (5,157,658)	$ 1,680,119	$ 22,665,857	$ 19,188,318
Net Cost Rate Base			$ 359,484,893	$ 99,264,945	$ 711,527,826	$ 1,170,277,664
Return on Rate Base -- Utility Operating Margin Divided by Rate Base			-1.43%	1.69%	3.19%	1.64%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name		Rurals		Large Industrials		Smelters		Total System
Cost of Service Summary -- Pro-Forma (Proposed Rate Increase)										
Operating Revenues										
Total Operating Revenue			$	99,720,079	$	33,424,364	$	262,052,077	$	395,196,520
Pro-Forma Adjustments:										
To Reflect Proposed Increase			$	14,172,003	$	3,228,566	$	22,553,396	$	39,953,965
Total Pro-Forma Operating Revenue			$	113,892,082	$	36,652,930	$	284,605,473	$	435,150,485
Operating Expenses										
Total Operating Expenses			$	104,877,738	$	31,744,245	$	239,386,220	$	376,008,202
Utility Operating Margins -- Pro-Formed for Increase			$	9,014,344	$	4,908,685	$	45,219,252	$	59,142,283
Net Cost Rate Base			$	359,484,893	$	99,264,945	$	711,527,826	$	1,170,277,664
Rate of Return				**2.51%**		**4.95%**		**6.36%**		**5.05%**

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Allocation Factors						
Energy Allocation Factors						
Energy Usage by Class		E01	0.233444	0.088538	0.678017	1.000000
Customer Allocation Factors						
Rev		R01	110,934,700	39,110,620	282,406,135	432,451,455
Energy		Energy	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
FAC Revenue Allocator		FACA	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Base Fuel Revenue Allocator		BSFL	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Fuel Expense Applicable to FAC Allocator		FACEX	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Energy - NonSmelter		EnergyNS	1	0	-	1
Energy - Smelter only		EnergyS	-	-	1	1
Customers (Metering Points)		Cust05	3	1	2	6
Energy - Rurals only		EnergyR	1.0000	-	-	1.0000
Demand Allocators						
Steam - Direct Assignment		STMD	-	-	-	-
Substation Allocator		SUBA	-	-	-	-
Production 1 CP Demands		1CP	554,980	151,856	850,000	1,556,837
Production 2 CP Demands		2CP	1,051,963	239,829	1,700,000	2,991,792
Production 4 CP Demands		4CP	2,036,530	473,879	3,400,000	5,910,409
Production 6 CP Demands		6CP	2,979,160	721,110	5,100,000	8,800,270
Production 12 CP Demands		12CP	5,172,279	1,424,048	10,200,000	16,796,327
Production CP Allocation Method Used:		CP	0.307941	0.084783	0.607276	1.000000
Sum of Individual Class Demands			5,226,823	1,751,743	10,200,000	17,178,566
Transmission 12 CP Demand		12CPTR	5,172,279	1,424,048	10,200,000	16,796,327

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Production Energy Allocation						
Production Energy Residual Allocator		PENGA	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Production Energy Costs			-	-	-	-
Member Specific Assignment			-	-	-	-
Production Energy Residual			74,066,421	28,091,138	215,119,013	317,276,572
Production Energy Total		PENGT	74,066,421	28,091,138	215,119,013	317,276,572
Production Energy Total Allocator		PENG	0.233444	0.088538	0.678017	1.000000
FAC Expense Residual Allocator		FACALL	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
FAC Expense Cost			-	-	-	-
Member Specific Assignment			-	-	-	-
FAC Expense Residual			25,821	9,793	74,993	110,607
FAC Expense Total		FACT	25,821	9,793	74,993	110,607
FAC Expense Allocator		FACAL	0.233444	0.088538	0.678017	1.000000
OSS Allocated Amount		OSSRBA	313,150,767	86,508,089	-	399,658,856
Off-System Sales Allocator						
Off-System Sales Revenue			4,898,710	1,353,272	-	6,251,982
Specific Assignment			-	-	70,291,505	70,291,505
Total OSS Assignments		TOSSA	4,898,710	1,353,272	70,291,505	76,543,487
			-	-	28,015,863	28,015,863
Estimated Gross Revenues for Smelter Surplus Sales	R		-	-	70,291,505	70,291,505
Energy Expenses for Smelter Surplus Sales	E					
Surplus Sales Credit						
Less: Adjustment to Reallocate Expenses						
Off-System Sales Variable Operating Costs Allocated on kWh			(10,746,839)	(4,075,949)	(31,213,193)	(46,035,981)
Off-System Sales Variable Operating Costs Allocated on Rate Base			2,946,247	813,902	42,275,642	46,035,791
Net Expense Adjustment			(7,800,593)	(3,262,046)	11,062,450	(189)
Off-System Sales Allocator		OSSALL	12,699,303	4,615,318	59,229,055	76,543,676
Smelter Off System Sales Revenues shown in COS						
Variable Expenses Allocated for Off-System Sales to Smelters in COS						
Off-System Sales Margins Allocated to Smelters in COS						
Removal of Purchase Power Expenses Related to Surplus and Curtailed Power Recorded in Accounts 555 (Alcan) and 557 (Century)						
Purchased Power Demand Allocated to all via CP			8,341,512	2,296,611	16,449,891	27,088,015
Purchased Power Demand To Be Reallocated			-	-	(4,065,092)	(4,065,092)
Recalculated CP Allocation			0	0	-	0
Purchased Power Demand Allocation Adjustment Factor		PPDAAF	0.784115	0.215885	-	1.0000000
Purchased Power Demand Allocation Adjustment			3,187,500	877,592	(4,065,092)	-

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Operating Expenses						
Expenses before Adjustments						
Production Demand			$ 54,815,438	$ 15,091,958	$ 97,747,856	$ 167,655,252
Production Energy			$ 68,787,409	$ 26,088,969	$ 199,786,613	$ 294,662,992
Production Steam - Direct Assignment			$ -	$ -	$ -	$ -
Transmission Demand			$ 9,767,051	$ 2,689,095	$ 19,261,126	$ 31,717,271
Distribution Substation			$ -	$ -	$ -	$ -
Distribution Other			$ -	$ -	$ -	$ -
Total			$ 133,369,898	$ 43,870,022	$ 316,795,596	$ 494,035,516
Expenses After Adjustments						
Production Demand			$ 54,815,438	$ 15,091,958	$ 97,747,856	$ 167,655,252
Production Energy			$ 68,787,409	$ 26,088,969	$ 199,786,613	$ 294,662,992
Production Steam - Direct Assignment			$ -	$ -	$ -	$ -
Transmission Demand			$ 9,767,051	$ 2,689,095	$ 19,261,126	$ 31,717,271
Distribution Substation			$ -	$ -	$ -	$ -
Distribution Other			$ -	$ -	$ -	$ -
Total			$ 133,369,898	$ 43,870,022	$ 316,795,596	$ 494,035,516
Expenses After Adjustments for Rate Calculation						
Production Demand			$ 37,837,616	$ 9,295,207	$ 30,050,335	$ 77,183,158
Production Energy			$ 68,787,409	$ 26,088,969	$ 199,786,613	$ 294,662,992
Production Steam - Direct Assignment			$ -	$ -	$ -	$ -
Transmission Demand			$ 9,767,051	$ 2,689,095	$ 19,261,126	$ 31,717,271
Distribution Substation			$ -	$ -	$ -	$ -
Distribution Other			$ -	$ -	$ -	$ -
Total			$ 116,392,076	$ 38,073,271	$ 249,098,074	$ 403,563,421
Rate Base						
Production Demand			$ 310,356,615	$ 85,448,352	$ 612,039,195	$ 1,007,844,162
Production Energy			$ 2,794,152	$ 1,059,737	$ 8,115,354	$ 11,969,243
Production Steam - Direct Assignment			$ -	$ -	$ -	$ -
Transmission Demand			$ 46,334,126	$ 12,756,856	$ 91,373,277	$ 150,464,259
Distribution Substation			$ -	$ -	$ -	$ -
Distribution Other			$ -	$ -	$ -	$ -
Total			$ 359,484,893	$ 99,264,945	$ 711,527,826	$ 1,170,277,664

Exhibit Seelye-4

Reconciliation of
Billing Determinants

Big Rivers Electric Corporation
Reconciliation of Billing Determinants
For the 12 Months Ended October 31, 2010

Rate	Billing Determinants		Charge		Billings
Rural Delivery Point Service					
Demand Charge		kW-Mo		7.37 /kW-Mo	
Kenergy	2,643,407				$ 19,481,910
Jackson Purchase	1,492,514				10,999,828
Meade County	1,091,806				8,046,610
	5,227,727				38,528,348
Energy Charge		kWh	$	0.02040 /kWh	
Kenergy	1,255,008,258				$ 25,602,168
Jackson Purchase	694,512,540				14,168,056
Meade County	499,627,006				10,192,391
	2,449,147,804				49,962,615
Total Demand and Energy Charges					$ 88,490,963
Green Power					401.36
Fuel Adjustment Clause					25,166,503
Environmental Surcharge					5,315,462
Unwind Surcredit					(8,038,629)
Total					$ 110,934,700
Revenues per Statement of Operations					$ 110,934,700
Difference					$ (0)
Large Industrial Customer Delivery Point Service					
Demand Charge	1,743,869	kW-Mo		10.15 /kW-Mo	$ 17,700,270
Energy Charge	928,887,170	kWh	$	0.01372 /kWh	12,739,688
Total Demand and Energy Charges					$ 30,439,958
Green Power					-
Power Factor Provision and Off-System Sales Credit					172,750
Fuel Adjustment Clause					9,525,471
Environmental Surcharge					2,025,233
Unwind Surcredit					(3,052,791)
Total					$ 39,110,620
Revenues Per Statement of Operations					$ 39,110,620
Difference					$ (0)
Total					**$ 150,045,320**

Exhibit Seelye-5

Analysis of Non-FAC PPA

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Non FAC PPA Base Calculation

	Expense Month	PP(m) $	S(m) kWh	Monthly Rate PP(m) / S(m) $ / kWh	Current Base PP(b) / S(b) $ / kWh	Monthly Factor $/ kWh
	(1)	(2)	(3)	(4)	(5)	(6)
1	Nov-09	857,210	823,074,275	0.001041	0.001750	(0.000709)
2	Dec-09	32,675	915,375,535	0.000036	0.001750	(0.001714)
3	Jan-10	1,269,343	955,577,721	0.001328	0.001750	(0.000422)
4	Feb-10	435,979	860,254,282	0.000507	0.001750	(0.001243)
5	Mar-10	434,796	872,673,993	0.000498	0.001750	(0.001252)
6	Apr-10	880,947	803,411,031	0.001097	0.001750	(0.000653)
7	May-10	996,887	852,213,743	0.001170	0.001750	(0.000580)
8	Jun-10	782,758	895,570,310	0.000874	0.001750	(0.000876)
9	Jul-10	836,859	936,197,462	0.000894	0.001750	(0.000856)
10	Aug-10	473,665	948,595,005	0.000499	0.001750	(0.001251)
11	Sep-10	503,904	838,888,879	0.000601	0.001750	(0.001149)
12	Oct-10	1,122,128	822,198,468	0.001365	0.001750	(0.000385)
13						
14	Total	8,627,151	10,524,030,704	0.000820	0.001750	(0.000930)

Exhibit Seelye-6

Summary of Revenue Increase

Big Rivers Electric Corporation
Calculation of Proposed Rate Increase
Based on the 12 Months Ended October 31, 2010

Proposed Rates

Class	Adjusted Revenue at Current Rates ($)	Adjusted Revenue at Proposed Rates ($)	Base Rate Revenue Increase ($)	TIER Adjustment Decrease ($)	Estimated Credits From Amortization of Non-FAC PPA Balance ($)	Sum of Base Rate Increase, TIER Decrease and Amortization of Non-FAC PPA Balance ($)	Sum of Base Rate Increase, TIER Decrease and Amortization of Non-FAC PPA Balance (%)	Impact of Lowering the Non-FAC PPA Base ($)	Net Increase ($)	Net Increase (%)
Rural	110,513,089	124,685,092	14,172,003	-	(2,340,068)	11,831,935	10.71%	(2,145,453)	9,686,481	8.77%
Large Industrial	39,260,372	42,488,938	3,228,566	-	(896,009)	2,332,557	5.94%	(813,705)	1,518,852	3.87%
Non-Smelter	149,773,461	167,174,030	17,400,569	-	(3,236,077)	14,164,492	9.46%	(2,959,159)	11,205,333	7.48%
Smelters	282,391,841	297,830,583	22,553,396	(7,114,653)	-	15,438,743	5.47%	-	15,438,743	5.47%
Total	432,165,302	465,004,614	39,953,965	(7,114,653)	(3,236,077)	29,603,235	6.85%	(2,959,159)	26,644,076	6.17%

Big Rivers Electric Corporation
Reconciliation of Billing Determinants
For the 12 Months Ended October 31, 2010

Rate			Billing Determinants	Current Rate Charge	Current Rate Billings	Proposed Rate before Non-FAC PPA Roll-in Charge	Proposed Rate before Non-FAC PPA Roll-in Billings	Proposed Rate after Non-FAC PPA Roll-in Charge	Proposed Rate after Non-FAC PPA Roll-in Billings
Rural Delivery Point Service									
Demand Charge	NCP	(current)	5,227,727 kW-Mo	7.3700 /kW-Mo	$ 38,528,348				
	CP	(proposed)	5,172,279 kW-Mo			10.1890 /kW-Mo	$ 52,700,351	10.1890	$ 52,700,351
Energy Charge			2,449,147,804 kWh	$ 0.02040 /kWh	49,962,615	$ 0.020400 /kWh	49,962,615	$ 0.019524 /kWh	47,817,162
Total Demand and Energy Charges					$ 88,490,963		$ 102,662,966		$ 100,517,512
Green Power					401.36		401.36		401.36
Fuel Adjustment Clause					25,166,503		25,166,503		25,166,503
Environmental Surcharge					5,315,462		5,315,462		5,315,462
Unwind Surcredit					(8,038,629)		(8,038,629)		(8,038,629)
Non-FAC PPA Accruals					-		-		2,145,453
Estimated Credits from Amort of NFPPA Balance							(2,340,068)		(2,340,068)
Temperature Normalization Adjustment			(20,667,174) kWh	$ 0.02040 /kWh	(421,610)	$ 0.020400 /kWh	(421,610)		(421,610)
Total					$ 110,513,089		$ 122,345,024		$ 122,345,024
Increase							$ 11,831,935		11,831,935
Percentage Increase							10.71%		10.71%
Large Industrial Customer Delivery Point Service									
Demand Charge			1,743,869 kW-Mo	10.15 /kW-Mo	$ 17,700,270	10.8975 /kW-Mo	$ 19,003,812	10.8975	$ 19,003,812
Energy Charge			928,887,170 kWh	$ 0.013715 /kWh	12,739,688	$ 0.015761 /kWh	14,639,952	$ 0.014885	13,826,246
Total Demand and Energy Charges					$ 30,439,958		$ 33,643,764		$ 32,830,059
Green Power					-				
Power Factor Provision and Off-System Sales Credit					172,750		185,472		185,472
Fuel Adjustment Clause					9,525,471		9,525,471		9,525,471
Environmental Surcharge					2,025,233		2,025,233		2,025,233
Unwind Surcredit					(3,052,791)		(3,052,791)		(3,052,791)
Non-FAC PPA Accruals					-		-		813,705
Estimated Credits from Amort of NFPPA Balance							(896,009)		(896,009)
Current Industrial Customer Adjustment - Demand			13,437 kW-Mo	10.15 /kW-Mo	136,384	10.8975 /kW-Mo	146,428		146,428
Current Industrial Customer Adjustment - Energy			974,674 kWh	$ 0.013715 /kWh	13,368	$ 0.015761 /kWh	15,362		15,362
Total			3,358,342,474 kWh		$ 39,260,372		$ 41,592,929		$ 41,592,929
Increase					$ 39,260,372		$ 2,332,557		$ 2,332,557
Percentage Increase							5.94%		5.94%

Big Rivers Electric Corporation
Calculation of Proposed Rate Increase
Based on the 12 Months Ended October 31, 2010

SMELTERS	Billing Units	Current Rate		Proposed Rate		Proposed Rate after Non-FAC PPA Roll-in	
		Rate	Billings	Rate	Billings	Rate	Billings
Base Energy Charge							
Base Fixed Energy Charge	7,297,080,000 kWh	0.028153 /kWh	$ 205,434,693.24	0.031244 /kWh	$ 227,988,088.84	0.030368 /kWh	$ 221,595,846.76
Base Variable Energy Charge	(183,758,640) kWh	0.012470 /kWh	(2,291,470.24)	0.012470 /kWh	(2,291,470.24)	0.012470 /kWh	(2,291,470.24)
Total Base Energy Charge	7,113,321,360 kWh		$ 203,143,223.00		$ 225,696,618.60		$ 219,304,376.52
Other Charges or Credits							
Supplemental Power (Section 4.3)			$ -		$ -		$ -
Backup Energy Charge (Section 4.4)	8,151,430 kWh	0.039977 /kWh	353,379.80		353,379.80		353,379.80
Transmission Charge (Section 4.5)			-		-		-
Excess Reactive Demand Charge (Section 4.6)			-		-		-
TIER Adjustment Charge (Section 4.7.1)			14,229,306.00		7,114,653.00		7,114,653.00
FAC (Section 4.8.1)			73,123,202.72		73,123,202.72		73,123,202.72
Non-FAC PPA			(6,337,959.88)		(6,337,959.88)		54,282.20
Environmental Surcharge (Section 4.8.3)			15,493,537.87		15,493,537.87		15,493,537.87
Amortization of Restructuring Amount (Section 16.5.1)			-		-		-
Less: Rebate (Section 4.9)			-		-		-
Less: Equity Development Credit (Section 4.10)			-		-		-
Surcharge (Section 4.11)			11,466,492.00		11,466,492.00		11,466,492.00
Surplus Sales (Section 4.13.1)	(769,627,000) kWh	0.038166 /kWh	(28,015,862.60)		(28,015,862.60)		(28,015,862.60)
Undeliverable Energy Sales (Section 4.13.1)			-		-		-
Potline Reduction Sales (Section 4.13.1)			-		-		-
Curtailment of Purchased Power (Section 4.13.2)	incl w/SS kWh	0.038166 /kWh	(1,717,347.75)		(1,717,347.75)		(1,717,347.75)
Economic Sales (Section 4.13.3)			-		-		-
Other Credits (Section 4.14)			-		-		-
Taxes (Section 4.15)			-		-		-
Other Amounts (Section 5.1)			(3,818.03)		(3,818.03)		(3,818.03)
Billing Adjustments			657,687.71		657,687.71		657,687.71
Total	6,351,845,790		$ 282,391,840.83		$ 297,830,583.43		$ 297,830,583.43
Increase (Decrease)					$ 15,438,742.60		$ 15,438,742.60
Percentage Increase (Decrease)					5.47%		5.47%

Exhibit Seelye-7

Non-Smelter Non-FAC PPA

Non-Smelter Non-FAC PPA

Applicability

Applicable in all territory served by Big Rivers' Member Cooperatives.

Availability

To all sales under the following Big Rivers standard rate schedules: (i) Rural Delivery Service, (ii) Large Industrial Customer, and (iii) Large Industrial Customer Expansion, but only to the extent of service priced under schedule LIC.

Definitions

Please see Section 4 for definitions common to all tariffs.

"Smelters" are the aluminum reduction facilities of Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, as further described in the Wholesale Smelter Agreements.

"Smelter Agreements" are the two Wholesale Electric Service Agreements each dated as of July 1, 2009, between Big Rivers and Kenergy with respect to service by Kenergy to a Smelter.

Description

The Non-Smelter Non-FAC PPA ("NSNFP") Factor shall be calculated as a per-kWh billing credit or charge applied on a monthly basis, for each applicable rate schedule as follows:

NSNFP Factor = RA / KWH

Where

RA is the balance in the NSNFP Regulatory Account, established pursuant to the March 6, 2009 Order of the Public Service Commission in Case No. 2007-00455, as of June 30th of the current year and determined as provided below in the "Calculation of Purchased Power Expense" section;
and

KWH is the estimated Non-Smelter Applicable Sales (NSS), defined below, for the twelve month service period beginning September 1st of the current year through and including August 31st of the following year

Non-Smelter Non-FAC PPA contd

The NSNFP Factor shall be calculated based upon the June 30th balance and applied to bills for service beginning September 1st of the current year. The current NSNFP Factor shall remain in place for service through and including August 31st of the following year, at which time it will be updated in accordance with the formula above.

An over- or under- recovery shall be calculated using actual amounts and shall be included in the NSNFP Regulatory Account balance for recovery in the subsequent period.

Special Conditions

1) First Twelve Months

For the initial implementation of this rate mechanism, the NSNFP Factor shall be designed to return the Regulatory Liability balance as of June 30, 2011, over twenty-four (24) months beginning with the bills for September 2011 service. After this factor has been in place for twenty-four (24) months, any remaining over- or under- recovery shall be included in the Non-FAC PPA Regulatory Account balance for recovery in the subsequent period.

2) Second Twelve Months

For the service periods beginning September 1, 2012, and ending August 31, 2013, two NSNFP Factors shall be in place. The first is the credit for months thirteen (13) through month twenty-four (24) of the credit noted in the First Twelve Months section above. The second is the NSNFP Factor calculated in accordance with the standard formula:

NSNFP Factor = RA / KWH

Where

RA is the Non-FAC PPA Regulatory Account balance as of June 30, 2012 and

KWH is the estimated Non-Smelter Applicable Sales (NSS) for the twelve (12) months beginning September 1, 2012 through and including August 31, 2013.

The two NSNFP Factors will be applied simultaneously over the twelve month service period from September 1, 2012 to August 31, 2013.

Non-Smelter Non-FAC PPA contd.

3) Third Twelve Months and Subsequent Twelve-Month Periods

For the service periods beginning September 1, 2013, only one NSNFP Factor shall be in place, calculated in accordance with the standard formula noted herein.

Calculation of Purchase Power Expense

Purchased Power Expense:
The monthly amount of purchased power expense that is recorded in the NSNFP Regulatory Account (PP(x)) is determined as provided in this section.

Definitions:

"Account" is the specified numbered account as set forth in the Uniform System of Accounts – Electric, promulgated under Bulletin 1767B-1 by the Rural Utilities Service, an agency of the U.S. Department of Agriculture.

"SEPA" is the Southeastern Power Administration, an agency of the U.S. Department of Energy, or any successor agency.

"Wholesale Smelter Agreements" are the Alcan Wholesale Agreement and the Century Wholesale Agreement.

Determination of the PP(x):

The PP(x) shall be determined in accordance with the following formula:

$$PP(x) = (PP(m)/S(m) - PP(b)/S(b)) \times NSS(m)$$

Where PP(m) is the current Purchased Power Costs for the month; S(m) is the current Applicable Sales; PP(b) is the Purchase Power Cost for the base period; and S(b) is the sales in the base period,

Non-Smelter Non-FAC PPA contd

For the initial base period, PP(b)/S(b) (the "Purchased Power Base") is $0.000874.

Purchased Power Costs (PP) shall be the sum of:

(a) The total cost of power purchased (including purchases from SEPA) that is expensed by Big Rivers to Account 555 (excluding those costs that are recovered through Big Rivers' FAC and excluding costs expensed to Account Nos. 555.150, 555.151, 555.152 and related accounts regarding Big Rivers' cost share of HMP&L's Station Two, and to Account No. 555.188 and related accounts regarding Big Rivers' purchase of back-up power for the Domtar cogenerator) including transmission and related costs that are expensed to Account 565.

(b) The total amount of any adjustments to Purchased Power Costs attributable to prior months, whether positive or negative; and

(c) The total cost of amounts credited by Big Rivers to Kenergy with respect to voluntary curtailments under Section 4.13.2 of either Smelter Wholesale Agreement to allow Big Rivers to avoid market priced purchases of power.

Less:

(d) The total cost of power purchased directly associated with sales (including related system energy losses) by Big Rivers either to non-Member purchasers of power or to Kenergy under either Wholesale Smelter Agreement for resale to either Smelter as energy products other than Base Monthly Energy, assuming SEPA power followed by the lowest cost power, whether generated or purchased, shall be allocated to Applicable Sales.

Applicable Sales (S) shall be all kilowatt-hours sold at wholesale by Big Rivers (a) to its Members under all electric rate schedules, including the Large Industrial Rate, for resale to Kentucky ratepayers (other than by Kenergy to the Smelters and to Domtar for Backup Power Service), and (b) to Kenergy as Base Monthly Energy as defined in each of the Wholesale Smelter Agreements.

RATES, TERMS AND CONDITIONS – SECTION 2

Non-Smelter Non-FAC PPA contd

Non-Smelter Applicable Sales (NSS) shall be all kilowatt-hours sold at wholesale by Big Rivers to its Members under all electric rate schedules, including the Large Industrial Rate, for resale to Kentucky ratepayers (other than by Kenergy to the Smelters and to Domtar for Backup Power Service).

Exhibit Seelye-8

Updated Midwest ISO
Attachment O

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing RUS Form 12 Data

For the 12 months ended 10/31/10
0

Big Rivers Electric Corporation

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)					$ 28,984,266
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 454	(page 4, line 30)	26,250	TP	0.96521	25,337
3	Account No 456	(page 4, line 33)	13,449,298	TP	0.96521	12,981,351
4	*Revenues from Grandfathered Interzonal Transactions*		0	TP	0.96521	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.96521	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					13,006,688
7a	Revenue Adjustment (Note W)					$0
7	NET REVENUE REQUIREMENT	(line 1 minus line 6 plus line 7a)				$ 15,977,578
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	1,399,694
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	0
10	Plus 12 CP of Network Load not in line 8				(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S)					0
14	Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	*Divisor (sum lines 8-14)*					1,399,694

Line No.						
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	11.415			
17	Network & P-to-P Rate ($/kW/Mo) (line 16 / 12)		0.951			
			Peak Rate		Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.220		$0.220	
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	0.044	Capped at weekly rate	$0.031	
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 times 1,000)	2.744	Capped at weekly and daily rates	$1.303	
21	FERC Annual Charge ($/MWh)	(Note E)	$0.000	Short Term	$0.000	Short Term
22			$0.000	Long Term	$0.000	Long Term

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing RUS Form 12 Data

For the 12 months ended 10/31/10

Big Rivers Electric Corporation

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total		(4) Allocator	(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	12h A.6.e	1,686,796,955	NA		
2	Transmission	12h A.11.e	237,659,206	TP	0.96521	229,390,235
3	Distribution	12h A.16.e	0	NA		
4	General & Intangible	12h A 1&17.e	18,511,051	W/S	0.13894	2,571,851
5	Common		0	CE	0.13894	0
6	TOTAL GROSS PLANT (sum lines 1-5)		1,942,967,212	GP=	11.939%	231,962,086
			0			
	ACCUMULATED DEPRECIATION					
7	Production	12h.B.1-4.f	790,847,523	NA		
8	Transmission	12h.B.5.f	107,564,747	TP	0.96521	103,822,204
9	Distribution	12h.B.6.f	0	NA		
10	General & Intangible	12h.B.7.f	6,300,770	W/S	0.13894	875,403
11	Common		0	CE	0.13894	0
12	TOTAL ACCUM DEPRECIATION (sum lines 7-11)		904,713,040			104,697,608
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	895,949,432			
14	Transmission	(line 2- line 8)	130,094,459			125,568,031
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	12,210,281			1,696,447
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		1,038,254,172	NP=	12.258%	127,264,478
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.12258	0
21	Account No. 283 (enter negative)		0	NP	0.12258	0
22	Account No. 190		0	NP	0.12258	0
23	Account No. 255 (enter negative)		0	NP	0.12258	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE	(Note G)	0	TP	0.96521	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated	4,764,063			1,685,643
27	Materials & Supplies (Note G)	12h G 4.d + 5.d	2,812,929	TE	0.86297	2,427,481
28	Prepayments	12a.B 24	3,296,852	GP	0.11939	393,596
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		10,873,844			4,506,721
30	RATE BASE (sum lines 18, 24, 25, and 29)		1,049,128,016			131,771,199

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing RUS Form 12 Data

For the 12 months ended 10/31/10

Big Rivers Electric Corporation

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	12a.A.8.b + A.16.b	13,736,318	TE	0.86297	11,854,069
2	Less Account 565	12i.A.8.a	3,065,817	TE	0.86297	2,645,717
3	A&G	12a.A.13.b + A.18.b	28,620,280	W/S	0.13894	3,976,386
4	Less FERC Annual Fees		0	W/S	0.13894	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		1,819,284	W/S	0.13894	252,764
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		641,009	TE	0.86297	553,174
6	Common		0	CE	0.13894	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		38,112,507			13,485,148
	DEPRECIATION EXPENSE					
9	Transmission	12h.B.5.c	5,182,459	TP	0.96521	5,002,143
10	General	12h.B.7.c	238,155	W/S	0.13894	33,088
11	Common		0	CE	0.13894	0
12	TOTAL DEPRECIATION (sum lines 9 - 11)		5,420,614			5,035,232
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll		0	W/S	0.13894	0
14	Highway and vehicle		0	W/S	0.13894	0
15	PLANT RELATED					
16	Property		0	GP	0.11939	0
17	Gross Receipts		0		zero	0
18	Other		0	GP	0.11939	0
19	Payments in lieu of taxes		0	GP	0.11939	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
	INCOME TAXES	(Note K)		NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD = (page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.12258	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		83,310,740	NA		10,463,886
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		126,843,860			28,984,266
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, page 2, line 3, column 10] (Note U) [Revenue requirement for facilities included on page 2, line 2, and also included in Attachment GG]		0			0
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30)		126,843,860			28,984,266

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing RUS Form 12 Data

For the 12 months ended 10/31/10

Big Rivers Electric Corporation

SUPPORTING CALCULATIONS AND NOTES

Line No.							
	TRANSMISSION PLANT INCLUDED IN ISO RATES						
1	Total transmission plant (page 2, line 2, column 3)					237,659,206	
2	Less transmission plant excluded from ISO rates (Note M)					0	
3	Less transmission plant included in OATT Ancillary Services (Note N)					8,268,970	
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)					229,390,235	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					0 96521	
	TRANSMISSION EXPENSES						
6	Total transmission expenses (page 3, line 1, column 3)					13,736,318	
7	Less transmission expenses included in OATT Ancillary Services (Note L)					1,454,938	
8	Included transmission expenses (line 6 less line 7)					12,281,380	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)					0 89408	
10	Percentage of transmission plant included in ISO Rates (line 5)					0 96521	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					0 86297	
	WAGES & SALARY ALLOCATOR (W&S)		$	TP	Allocation		
12	Production		38,542,468	0 00	0		
13	Transmission		6,480,848	0.97	6,255,357		
14	Distribution		0	0.00	0	W&S Allocator	
15	Other		0	0 00	0	($ / Allocation)	
16	Total (sum lines 12-15)		45,023,316		6,255,357 =	0 13894	
	COMMON PLANT ALLOCATOR (CE) (Note O)		$		% Electric	Labor Ratio	
17	Electric		1,943,034,107		(line 17 / line 2(	(line 16)	CE
18	Gas		0		1.00000 *	0.13894	= ###
19	Water		0				
20	Total (sum lines 17-19)		1,943,034,107				
	RETURN (R)		$				
21	Long Term Interest 12a A 22 b		$47,622,710				
			$	%	Cost (Note P)	Weighted	
22	Long Term Debt	12a B 45 + B 46 + B 51 + B52	815,322,539	68%	0 0584	0.0397	=WCLTD
23	Proprietary Capital	12a B 38	385,705,395	32%	0.1238	0.0398	
24	Total (sum lines 22-23)		1,201,027,934	100%		0 0794	=R
25				Proprietary Capital Cost Rate =		12.38%	
26				TIER =		0 74	
	REVENUE CREDITS						
						Load	
	ACCOUNT 447 (SALES FOR RESALE)						
27	a Bundled Non-RQ Sales for Resale			(Note Q)		0	
28	b. Bundled Sales for Resale included in Divisor on page 1					0	
29	Total of (a)-(b)					0	
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)					$26,250	
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)						
31	a. Transmission charges for all transmission transactions					$13,752,495	
32	b Transmission charges for all transmission transactions included in Divisor on page 1					$303,198	
32a	c. Transmission charges associated with Schedule 26 (Note V)					$0	
33	Total of (a)-(b)-(c)					$13,449,298	

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing RUS Form 12 Data

For the 12 months ended 10/31/10

Big Rivers Electric Corporation

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col #)
References to data from RUS Form 12 are indicated as: # x.y.z (page,section, line, column)
To the extent the page references to RUS Form 12 are missing, the entity will include a "Notes" section in the RUS 12 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term
C	LF as defined above at time of ISO coincident monthly peaks
D	LF as defined above at time of ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assetsor liabilities related to FASB 106 or 109. Balance of
G	Transmission related only.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to
I	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state
	Inputs Required: FIT = 0.00%
	SIT= 0.00% (State Income Tax Rate or Composite SIT)
	p = 0.00% (percent of federal income tax deductible for state purposes)
L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be
Q	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1.
T	The revenues credited on page 1, lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff)
U	Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG and recovered under Schedule 26 of the
V	Removes from revenue credits revenues that are distributed pursuant to Schedule 26 of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have
W	Line 7a reflects an adjustment to incorporate Big Rivers' existing OATT rates as approved by the Kentucky Public Service Commission (KPSC) under whose jurisdiction Big Rivers' rates

Exhibit Seelye-9

FERC Order in
Docket No. ER11-15-000

133 FERC ¶ 61,175
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Midwest Independent Transmission System Operator, Inc. and Big Rivers Electric Corporation — Docket Nos. ER11-16-000, ER11-15-000

ORDER CONDITIONALLY ACCEPTING PROPOSED TARIFF REVISIONS

(Issued November 24, 2010)

1. In this order, we address two separate filings, Docket Nos. ER11-15-000 and ER11-16-000, submitted by Big Rivers Electric Corporation (Big Rivers) and Midwest Independent Transmission System Operator, Inc. (Midwest ISO) (collectively, Applicants) on October 4, 2010 to revise Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) to facilitate Big Rivers joining Midwest ISO as a transmission-owning member on December 1, 2010.[1] With regard to Docket No. ER11-15-000, we conditionally accept for filing Big Rivers' Attachment O formula rate, to be effective December 1, 2010 through and including December 31, 2011. With regard to Docket No. ER11-16-000, we conditionally accept for filing Applicants' proposed revisions to Schedules 7, 8, 9, and 26 of Midwest ISO's Tariff, to be effective as of the date of Big Rivers' full integration into Midwest ISO, as requested, subject to a compliance filing as discussed below.

I. Background

2. Midwest ISO is a Commission-approved Regional Transmission Organization (RTO) that provides transmission service pursuant to rates, terms and conditions of its Tariff on file with the Commission. Among other things, Midwest ISO provides point-to-point transmission service and network integration transmission service under its Tariff. Big Rivers is a not-for-profit generation and transmission cooperative providing

[1] As the administrator of the Tariff, Midwest ISO joins Big Rivers in this filing to amend the Tariff but takes no position on the substance of the filing.

wholesale power and transmission service to its three-member distribution cooperatives in Western Kentucky. Big Rivers' three-member distribution cooperatives are: Kenergy Corporation; Jackson Purchase Energy Corporation; and Meade County Rural Electric Cooperative Corporation. Big Rivers has announced its intent to join Midwest ISO as a transmission owner and plans to integrate its facilities into Midwest ISO on December 1, 2010.

II. Description of Filings

A. Docket No. ER11-15-000

3. On October 4, 2010, Applicants filed revisions to Midwest ISO's Tariff to include Big Rivers' company-specific Attachment O template. Applicants state that Big Rivers is currently seeking approval from the Kentucky Public Service Commission (Kentucky Commission) to transfer functional control of its transmission facilities to Midwest ISO on December 1, 2010.[2] Applicants seek approval of deviations from Midwest ISO's Attachment O formula rate template (Non-Levelized Rate Formula Template Using Rural Utilities Service Form 12 Data). Specifically, Applicants request, on an interim basis, to use rates for firm and non-firm point-to-point and network integration transmission services currently contained in Big Rivers' safe harbor Open Access Transmission Tariff (OATT), which the Kentucky Commission has approved, until such time that Big Rivers can obtain approval from the Kentucky Commission to use Midwest ISO's Attachment O formula rate.[3]

4. Applicants state that the Kentucky Commission approved an "unwind" of Big River's long-term lease of its generation facilities to various subsidiaries of E.ON US LLC (Unwind Transaction), which stipulated that Big Rivers is obligated to file with the Kentucky Commission to adjust its rates, including its transmission rates, within

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[2] Subsequent to the date of filing in this proceeding, the Kentucky Commission approved Big Rivers' request to transfer functional control of its transmission system to Midwest ISO. *In re* Application of Big Rivers Elec. Corp. for Approval to Transfer Functional Control of its Transmission System to Midwest Indep. Transmission Sys. Operator, Inc., Case No. 2010-00043, at 12 (Nov. 1, 2010).

[3] Applicants state that Big Rivers filed its safe harbor OATT with the Commission on April 22, 2009 in Docket No. NJ09-3-000. The Commission conditionally accepted Big Rivers' OATT on September 17, 2009, subject to a compliance filing addressing certain non-rate terms and conditions. Applicants Transmittal Letter, Docket No. ER11-15-000, at 3-4 (citing *Big Rivers Elec. Corp.*, 128 FERC ¶ 61,264 (2009)). Applicants state that Big Rivers made the compliance filing on December 16, 2009, but that the Commission has not yet acted on the compliance filing. *Id.* at 4.

three years of the date of closing of the Unwind Transaction (July 16, 2009).[4] Applicants state that Big Rivers anticipates submitting a filing with the Kentucky Commission to adjust its transmission rates to be effective no later than January 1, 2012.[5] Applicants state that Big Rivers will seek approval from the Kentucky Commission at that time to adjust its transmission rates to utilize the Midwest ISO Attachment O formula rate. Until the Kentucky Commission approves such adjustments, however, Applicants state that it is necessary for Big Rivers to utilize certain limited variances from the Attachment O formula rate.[6] Accordingly, Applicants seek to utilize Big Rivers' existing OATT rates until such time as it can obtain approval from the Kentucky Commission, as described above.

5. Specifically, Applicants propose the following deviations to Big Rivers' Attachment O:

- Revenue Adjustment, page 1, line 7a: As explained in a new Note W on page 5 to Big Rivers Attachment O, "Line 7a reflects an adjustment to incorporate Big Rivers' existing OATT rates as approved by the [Kentucky Commission] under whose jurisdiction Big Rivers' rates are subject. The rates as derived using the Midwest ISO Tariff Attachment O formul[a] will be adjusted to equal the existing rates approved by the [Kentucky Commission]." Applicants state that the Revenue Adjustment is necessary to adjust the rates up or down in order to produce the revenue requirement that is consistent with Big Rivers' current OATT rates. Applicants state that Big Rivers cannot change this revenue requirement without the approval from the Kentucky Commission.[7]

- Net Revenue Requirement, page 1, line 7: Applicants state that Big Rivers has included language to reflect that the Net Revenue Requirement includes the Revenue Adjustment.[8]

6. Applicants assert that the deviations from Midwest ISO's Attachment O formula rate are just and reasonable. In addition, Applicants argue that Big Rivers' circumstances are unique in that it will be the only Midwest ISO transmission owner whose rates under

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[4] *Id.*

[5] *Id.*

[6] *Id.*

[7] *Id.*

[8] *Id.*

Midwest ISO's Tariff are subject to state commission approval. Applicants request an effective date of December 1, 2010, and that the Commission issue an order accepting these tariff sheets no later than November 24, 2010.[9]

B. Docket No. ER11-16-000

7. Also, on October 4, 2010, Applicants filed revisions to: Schedule 7 (Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service); Schedule 8 (Non-Firm Point-to-Point Transmission Service); Schedule 9 (Network Integration Transmission Service); and Schedule 26 (Network Upgrade Charge From Transmission Expansion Plan) of Midwest ISO's Tariff to reflect the addition of Big Rivers as a pricing zone in connection with its proposed integration into Midwest ISO. The proposed revisions adopt Midwest ISO's Commission-accepted transmission formula rate template contained in Attachment O to the Tariff, with the exception of the deviations outlined above in Docket No. ER11-15-000. According to Applicants, by transitioning to Midwest ISO's Attachment O formula rate, Big Rivers will fully migrate to the Tariff and be subject to the same terms and conditions of service as are other Midwest ISO transmission owners that utilize the Attachment O formula rate.[10]

8. Applicants request that the Commission accept the proposed revisions, without condition or suspension, to be effective as of the date of Big Rivers' full integration into Midwest ISO, which is currently scheduled for December 1, 2010. Applicants assert that granting this request is consistent with prior Commission orders wherein the Commission addressed formula rates for transmission owners in Midwest ISO and other RTOs in which the Commission approved those rates with no more than nominal suspension periods.[11]

III. Notice of Filing and Responsive Pleadings

9. Notice of Applicants' filings in Docket Nos. ER11-15-000 and ER11-16-000 were published in the *Federal Register*, 75 Fed. Reg. 63,457 (2010), with interventions or protests due on or before October 25, 2010.

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[9] *Id.* at 2.

[10] Applicants Transmittal Letter, Docket No. ER11-16-000, at 2.

[11] *Id.* at 1 (citing *Va. Elec. & Power Co.*, 123 FERC ¶ 61,098 (2008); *Duquesne Light Co.*, 118 FERC ¶ 61,087 (2007); *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284 (2007); *Michigan Elec. Transmission Co.*, 117 FERC ¶ 61,314 (2006); *Int'l Transmission Co.*, 116 FERC ¶ 61,036 (2006)).

10. American Municipal Power, Inc. and Consumers Energy Company filed timely motions to intervene in Docket Nos. ER11-15-000 and ER11-16-000. Midwest ISO Transmission Owners (Midwest ISO TOs)[12] filed a timely motion to intervene and comments in Docket Nos. ER11-15-000 and ER11-16-000. Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier) filed a timely motion to intervene and comments in Docket No. ER11-16-000. Big Rivers filed an answer to Midwest ISO TOs' comments in Docket No. ER11-15-000.

IV. Discussion

A. Procedural Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2010), the timely, unopposed motions to intervene serve to make the entities that filed them parties to the proceedings in which they intervened. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2010), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept Big Rivers' answer because it has provided information that assisted us in our decision-making process.

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[12] Midwest ISO TOs for purposes of this filing consist of: Ameren Services Company, as agent for Union Electric Company, Central Illinois Public Service Company, Central Illinois Light Co., and Illinois Power Company; American Transmission Company LLC; American Transmission Systems, Inc., a subsidiary of FirstEnergy Corp.; City of Columbia Water and Light Department (Columbia, Missouri); City Water, Light & Power (Springfield, Illinois); Dairyland Power Cooperative; Duke Energy Corporation for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; Michigan Electric Transmission Company, LLC; Michigan Public Power Agency; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company and Northern States Power Company, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Minnesota Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

B. Substantive Matters

1. Docket No. ER11-15-000

a. Comments

12. Midwest ISO TOs state that they do not oppose the use of Big Rivers' Attachment O, but they believe that certain aspects of the filing should be modified or clarified. Specifically, Midwest ISO TOs assert that the Commission should require Applicants to modify Big Rivers' Attachment O to state that it is being adopted on an interim basis and shall remain in effect no later than December 31, 2011. At that point, Midwest ISO TOs state, Applicants can make the necessary filings to adopt the appropriate formula rate for Big Rivers. Midwest ISO TOs express concern that while Big Rivers anticipates filing the standard Attachment O template to become effective January 1, 2012, Big Rivers makes no firm commitment to do so. Midwest ISO TOs state that although Big Rivers is making these statements in good faith, this lack of a firm end-date for the use of Big Rivers' Attachment O could mean that the rate formula remains in use indefinitely in a manner that is different from the representations made in the instant filing. Alternatively, Midwest ISO TOs request that the Commission condition its acceptance of Big Rivers' Attachment O upon Big Rivers submitting a filing to adopt an appropriate formula rate for Big Rivers, to become effective no later than January 1, 2012.[13]

13. In addition, Midwest ISO TOs assert that Applicants need to address the impact of Schedules 26 and proposed 26-A (Multi-Value Project Usage Rate)[14] and the charges allocated and billed to the Big Rivers pricing zone during the interim period. Midwest ISO TOs state that Midwest ISO's Tariff contains a number of additional charges other than the base transmission charges (i.e., Schedules 7, 8, and 9), including charges under Schedule 26 and proposed Schedule 26-A. Midwest ISO TOs state that charges imposed under these schedules will be billed to and collected from Big Rivers, but it is unclear how Big Rivers will treat any charges allocated and billed to its zone under Schedule 26 and proposed Schedule 26-A. For example, Midwest ISO TOs question whether Big Rivers will treat these charges as an add-on charge that is recovered in addition to its proposed rates or, alternatively, be deemed to be part of Big Rivers' base transmission rates. Because Schedule 26 and proposed Schedule 26-A are intended to recover the

[13] Midwest ISO TOs Comments, Docket No. ER11-15-000, at 5.

[14] On July 15, 2010, Midwest ISO submitted to the Commission a new Schedule 26-A as part of a joint filing with certain Midwest ISO Transmission Owners in Docket No. ER10-1791-000. The proposed Schedule 26-A would establish a new category of transmission projects designated as Multi-Value Projects and a corresponding cost allocation methodology for such projects. This filing is pending before the Commission.

costs of new transmission facilities for every transmission owner that has revenue requirements for facilities that qualify, Midwest ISO TOs claim that these charges recover more than just Big Rivers' revenue requirements. Midwest ISO TOs contend that Applicants should be required to clarify how any Schedule 26 and proposed Schedule 26-A charges allocated and billed to the Big Rivers' zone during the interim period will be treated for purposes of Big Rivers' Attachment O.[15]

14. Finally, Midwest ISO TOs state that Applicants should clarify the effects of Big Rivers' Attachment O on Midwest ISO's drive-out and drive-through rates and on revenue distribution under Midwest ISO's Transmission Owners Agreement.[16] Specifically, Midwest ISO TOs state that the rates for drive-out and drive-through transmission services are based on the total net revenue requirements for all transmission owners within Midwest ISO, divided by total load within Midwest ISO.[17] In addition, Midwest ISO TOs state that under Midwest ISO's Transmission Owners Agreement, revenues for certain transmission services, including drive-out and drive-through transactions, are distributed to all transmission owners.[18] Midwest ISO TOs argue that acceptance of Big Rivers' Attachment O should have no impact on the method used to develop the Midwest ISO drive-out and drive-through rates or the resulting revenue distribution. Regardless of whether the Commission accepts Big Rivers' Attachment O, Midwest ISO TOs state that Applicants should clarify that: (1) transmission customers taking service under the Tariff that exit the Big Rivers pricing zone will pay the drive-out and drive-through rate established pursuant to Attachment O; and (2) the distribution of revenues to the Midwest ISO Transmission Owners will include transmission revenues deriving from transmission service exiting the Big Rivers pricing zone.[19]

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[15] Midwest ISO TOs Comments, Docket No. ER11-15-000, at 6.

[16] The formal name of the Transmission Owners Agreement is the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation.

[17] Midwest ISO TOs Comments, Docket No. ER11-15-000, at 7 (citing Midwest ISO Tariff, FERC Electric Tariff, Third Revised Vol. No. 1, Second Revised Sheet No. 1316).

[18] *Id.* (citing Midwest ISO, Transmission Owners Agreement, Appendix C, § III.A.7 and III.B).

[19] *Id.*

b. Answer

15. In response to Midwest ISO TOs' concern that the interim formula rate lacks a firm end-date, Big Rivers reiterates that its transmission rates are subject to the jurisdiction of the Kentucky Commission, and cannot be changed without the Kentucky Commission's approval. Accordingly, Big Rivers states that it cannot commit to a firm end-date for the use of the proposed Big Rivers' Attachment O. However, Big Rivers does commit to submitting a filing with the Commission, to become effective no later than January 1, 2012, to propose a rate formula to be employed thereafter. In the event that Big Rivers does not receive approval from the Kentucky Commission to utilize a different rate, Big Rivers asserts that it will seek to retain the existing formula rate. However, Big Rivers states that it would not object to a Commission order that allows Big Rivers' Attachment O to remain in effect only through December 31, 2011.[20]

16. With regard to Midwest ISO TOs' request for clarification concerning how charges under Schedule 26 and proposed Schedule 26-A will be treated, Big Rivers clarifies that it is not proposing to change Big Rivers' Attachment O to reflect any amounts that may be allocated and billed to Big Rivers' zone. Big Rivers states that the formula rate in the proposed Big Rivers' Attachment O reflects the cost of existing facilities, and it is unlikely that Big Rivers would be assessed any charges under these schedules during the interim period. Big Rivers, however, asserts that if these charges should occur, the charges will be paid, as required under Midwest ISO's Tariff, and would not result in any changes to Big Rivers' Attachment O rates.[21]

17. Finally, in response to the requested clarification concerning the impact of Big Rivers' Attachment O on Midwest ISO's drive-out and drive-through rates, Big Rivers states that its Attachment O is not intended to have any impact on the method used to develop Midwest ISO's drive-out and drive-through rates or the resulting revenue distribution under Midwest ISO's Transmission Owners Agreement.[22]

c. Commission Determination

18. We will conditionally accept Big Rivers' Attachment O formula rate. As an initial matter, we find it reasonable to accept Big Rivers' non-conforming Attachment O until such time that Big Rivers receives approval from the Kentucky Commission to use the Midwest ISO Attachment O formula rate. We find that the completion of the Unwind

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[20] Big Rivers Answer at 3.

[21] *Id.* at 3-4.

[22] *Id.* at 4.

Transaction, coupled with Big Rivers rates being subject to the Kentucky Commission authority, present unique circumstances for Big Rivers' Attachment O formula rate.[23] Thus, we find it appropriate to allow Big Rivers to adjust its revenue up or down commensurate with its state-approved transmission service rates. However, as Midwest ISO TOs point out, we are concerned that Big Rivers' non-conforming Attachment O lacks a firm end-date.[24] Therefore [consistent with Big Rivers' answer,] we conditionally accept Big Rivers' Attachment O formula rate to be effective December 1, 2010 through and including December 31, 2011 (Interim Period). We note, however, that this acceptance with an end-date of December 31, 2011 does not foreclose Applicants from making a filing at an earlier date to adopt an appropriate formula rate for Big Rivers.

19. With respect to Midwest ISO TOs concerns regarding Big Rivers' impact on Schedule 26 and proposed Schedule 26-A, we find that Big Rivers' answer addresses Midwest ISO TOs concern and clarifies that Big Rivers is unlikely to be assessed any charges under Schedule 26 or proposed Schedule 26-A prior to January 1, 2012 [but should that occur, the charges will be paid by the zonal load as required under the Tariff and would not result in any changes to Big Rivers' Attachment O rates].

20. Finally, with regard to Midwest ISO TOs request for clarification concerning the impact of Big Rivers' proposed Attachment O on drive-out and drive-through rates and the resulting revenue distribution pursuant to Midwest ISO's Transmission Owners Agreement, we find that Big Rivers' answer provides Midwest ISO TOs requested confirmations and therefore addresses their concerns. Big Rivers clarifies that its proposed Attachment O is not intended to have any impact on the method for calculating these rates or the associated revenue distribution. Big Rivers states that it concurs with Midwest ISO TOs clarification.

21. Accordingly, we will conditionally accept for filing Big Rivers' Attachment O formula rate, as clarified and modified in Big Rivers' answer, to be effective December 1, 2010 through and including December 31, 2011, as discussed above.

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[23] We note that the Commission previously accepted Big Rivers' transmission service rates contained within its safe harbor OATT. *See supra* note 3.

[24] Applicants anticipate submitting a filing to the Commission to adjust its rates to utilize the Midwest ISO Attachment O formula rate to be effective no later than January 1, 2012. *See supra* P 4.

2. Docket No. ER11-16-000

a. Comments

22. Midwest ISO TOs and Hoosier request that Midwest ISO clarify which of Big Rivers' planned or proposed transmission projects will be subject to cost allocation pursuant to Attachment FF of Midwest ISO's Tariff and cost recovery pursuant to Schedule 26.[25] Midwest ISO TOs and Hoosier state that under the Midwest ISO Transmission Expansion Plan (MTEP) process, set forth in Attachment FF of Midwest ISO's Tariff, projects are subject to a determination of cost allocation at the time the projects are approved.[26] Because Big Rivers is not yet a Transmission Owner within Midwest ISO, Midwest ISO TOs and Hoosier argue that Big Rivers should have no planned or proposed projects that are subject to cost allocation under these provisions prior to the MTEP 2011 planning cycle at the earliest. Midwest ISO TOs and Hoosier note that the Commission directed Midwest ISO to provide similar clarifications in proceedings involving the integration of Dairyland Power Cooperative and MidAmerican Energy Company into Midwest ISO.[27] If Midwest ISO cannot or does not provide such clarification, Hoosier requests that the Commission require Applicants to provide justification for including the projects in question prior to approving the proposed revisions to the Tariff.[28]

b. Commission Determination

23. We will conditionally accept the proposed revisions to Schedules 7, 8, 9, and 26 of Midwest ISO's Tariff to reflect the addition of Big Rivers as a pricing zone in connection with its proposed integration with Midwest ISO, to be effective as of the date of Big

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[25] Midwest ISO TOs Comments, Docket No. ER11-16-000, at 3; Hoosier Comments at 3.

[26] Midwest ISO TOs Comments, Docket No. ER11-16-000, at 3 (citing Midwest ISO, FERC Electric Tariff, Third Revised Vol. No. 1, Second Substitute Original Sheet No. 1839C.01); Hoosier Comments at 3 (citing Midwest ISO, FERC Electric Tariff, Third Revised Vol. No. 1, Substitute Original Sheet No. 1840).

[27] Midwest ISO TOs Comments, Docket No. ER11-16-000, at 4 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,187, at P 14 (2010) (*Dairyland*); *Midwest Indep. Transmission Sys. Operator, Inc.*, 128 FERC ¶ 61,046, at P 61 (2009) (*MidAmerican*)).

[28] Hoosier Comments at 4.

Rivers' full integration into Midwest ISO, which is currently scheduled for December 1, 2010, as requested, subject to the compliance filing ordered below.

24. With respect to Midwest ISO TOs' and Hoosier's requests for Midwest ISO to clarify which of Big Rivers' projects will be subject to cost allocation pursuant to Attachment FF of Midwest ISO's Tariff and cost recovery pursuant to Schedule 26, we will require, consistent with *Dairyland* and *MidAmerican*, that Applicants provide these clarifications in a compliance filing, due within 30 days of the date of this order.

The Commission orders:

(A) Big Rivers' Attachment O formula rate is hereby conditionally accepted for filing, to be effective December 1, 2010 through and including December 31, 2011, as discussed in the body of this order.

(B) The proposed revisions to Schedules 7, 8, 9, and 26 of Midwest ISO's Tariff are hereby conditionally accepted for filing, to be effective as of the date of Big Rivers' full integration into Midwest ISO, as requested, as discussed in the body of this order.

(C) Applicants are hereby directed to make a compliance filing, due within 30 days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Exhibit Seelye-10

Temperature Normalization Adjustment

Big River Electric Corporation
Temperature Normalization Adjustment
12 Months Ended October 31, 2010

#	Item		Temperature Normalization Adjustment with Banding
(1)	Normalization Adjustment - kWh		(20,667,174)
(2)	Rural Charge per kWh	$	0.0204
(3)	**Revenue Adjustment**	**$**	**(421,610)**
(4)	Base Fuel and Variable Cost per kWh	$	0.01429
(5)	**Expense Adjustment**	**$**	**(295,293)**
(6)	Net Adjustment	$	(126,318)

Big River Electric Corporation
Base Fuel Cost and Variable O&M Expense
12 Months Ended October 31, 2010

Acct	Description		Test Year Expenses
512	MAINTENANCE OF BOILER PLANT	$	30,113,309
513	MAINTENANCE OF ELECTRIC PLANT		6,251,804
514	MAINTENANCE OF MISC STEAM PLANT		877,364
554	MAINTENANCE OF ELECTRIC PLANT - HYDRO		-
545	MAINTENANCE OF MISC HYDRO PLANT		-
558	DUPLICATE CHARGES		-
Total Variable Production Expenses		$	37,242,478
Total Sales (kWh)			10,436,840,268
Variable O&M Expenses per kWh			0.00357
FAC Base			0.01072
Total			0.01429

Big River Electric Corporation
Determination of Adjusted kWh Sales
12 Months Ended October 31, 2010

Year	Month	Coefficient	Actual Sales	Cooling Degree Days	Heating Degree Days	Normal Cooling Degree Days beyond 1 SD	Normal Heating Degree Days beyond 1 SD	Normal Sales	Proposed Adjustment	Normal Cooling Degree Days Plus 1 SD	Normal Cooling Degree Days Less 1 SD	Normal Heating Degree Days Plus 1 SD	Normal Heating Degree Days Less 1 SD
2009	11	66,685.5	165,507,760	-	435	-	-	165,507,760	0.0%	-	-	613	419
2009	12	99,133.9	237,687,050	-	918	-	-	237,687,050	0.0%	-	-	1,010	704
2010	1	137,685.3	263,265,220	-	1,115	-	32	258,927,129	-1.6%	-	-	1,083	795
2010	2	121,119.1	225,473,574	-	932	-	74	216,563,331	-4.0%	-	-	858	628
2010	3	68,216.7	179,449,879	-	533	-	-	179,449,879	0.0%	-	-	641	442
2010	4	42,939.3	141,319,505	48	140	-	-	141,319,505	0.0%	55	8	337	187
2010	5	110,630.5	170,661,972	181	47	-	-	170,661,972	0.0%	185	66	110	30
2010	6	133,344.1	231,319,542	432	-	52	-	224,439,992	-3.0%	381	261	-	-
2010	7	194,822.6	251,219,016	496	-	-	-	251,219,016	0.0%	512	373	-	-
2010	8	162,531.1	251,270,888	497	-	3	-	250,731,599	-0.2%	494	315	-	-
2010	9	129,312.1	184,587,328	218	20	-	-	184,587,328	0.0%	262	136	72	6
2010	10	33,870.3	147,386,070	29	200	-	-	147,386,070	0.0%	66	11	298	162
			2,449,147,804	1,901	4,340	55	105	2,428,480,630	**-0.8%**				
						Difference		(20,667,174)					

Note: This analysis was prepared by GDS Associates, Inc.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATIONS OF BIG RIVERS ELECTRIC CORPORATION FOR: (1) APPROVAL OF WHOLESALE TARIFF ADDITIONS FOR BIG RIVERS ELECTRIC CORPORATION, (2) APPROVAL OF TRANSACTIONS, (3) APPROVAL TO ISSUE EVIDENCES OF INDEBTEDNESS, AND (4) APPROVAL OF AMENDMENTS TO CONTRACTS; AND OF E.ON U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING, INC. FOR APPROVAL OF TRANSACTIONS	)	CASE NO. 2007-00455

O R D E R

On October 9, 2008, Big Rivers Electric Corporation ("Big Rivers"), E.ON U.S. LLC ("E.ON"), Western Kentucky Energy Corp. ("WKEC"), and LG&E Energy Marketing, Inc. ("LEM") filed a joint amended application requesting approval of the early termination of a 1998 lease under which generating plants owned or controlled by Big Rivers have been operated by WKEC. (E.ON, WKEC, and LEM are referred to collectively as "E.ON Entities," while Big Rivers and the E.ON Entities are referred to collectively as "Applicants.") Approval is also requested for dozens of transaction documents, tariffs, and financing arrangements necessary to implement the early termination of the lease, which is referred to as the "Unwind Transaction."

PARTIES

Big Rivers is a rural electric cooperative corporation organized pursuant to KRS Chapter 279. Big Rivers owns electric generation and transmission facilities and purchases, transmits, and sells electricity at wholesale, and it is a utility subject to the Commission's jurisdiction under KRS Chapter 278. Big Rivers exists for the principal purpose of providing the wholesale electricity requirements of its three member distribution cooperatives, Jackson Purchase Energy Corporation ("Jackson Purchase"), Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation ("Meade County"). Big Rivers is owned by these three member cooperatives and they in turn provide retail electric service to approximately 110,000 customers located in 22 western Kentucky counties.

E.ON is a U.S.-based holding company whose subsidiaries include WKEC and LEM. WKEC is engaged in the business of leasing and operating electric generation assets owned or leased by Big Rivers or the city of Henderson, Kentucky, while LEM is currently engaged in the business of purchasing and selling electric power in wholesale markets, including the power produced by WKEC. None of these E.ON Entities are utilities subject to the Commission's jurisdiction under KRS Chapter 278.

In addition to the Applicants, intervention was requested by and granted to the following parties: Alcan Primary Products Corporation ("Alcan"); Century Aluminum of Kentucky General Partnership ("Century"); the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); City of Henderson Utility Commission d/b/a Henderson Municipal Power and Light ("HMPL"); Kentucky

Industrial Utility Customers, Inc. ("KIUC"); International Brotherhood of Electrical Workers ("IBEW"); Jackson Purchase; Kenergy; and Meade County.

Alcan, which is located in Sebree, Kentucky, and Century, which is located in Hawesville, Kentucky, both operate aluminum smelters and are the largest electric customers on the Big Rivers system. Due to the nature of the aluminum smelting process, they operate 24 hours a day, 7 days a week, at a 98-percent load factor. Alcan's load is approximately 368 MW, while Century's load is approximately 482 MW. Alcan and Century are both retail customers of Kenergy and they are referred to collectively as the "Smelters."

HMPL is an electric utility owned by the city of Henderson, Kentucky. HMPL owns generation, transmission, and distribution facilities and also provides broadband service. IBEW is the bargaining representative for the union employees at the Big Rivers-owned generating plants.

PROCEDURAL HISTORY

The Applicants filed their initial joint application on December 28, 2007, and the Commission held informal conferences on January 10, 2008 and January 22, 2008. By Order dated January 22, 2008, a procedural schedule was established for the further processing of this case. The schedule provided for discovery on the joint application, Intervenor testimony, discovery on Intervenor testimony, rebuttal testimony, a hearing, and an opportunity for the parties to file post-hearing briefs.

Additional informal conferences were held at the Commission's offices on February 19, 2008; March 24, 2008; May 9, 2008; May 15, 2008; June 19, 2008; June

26, 2008; October 20, 2008; and November 25, 2008. A public hearing was held on December 2 and 3, 2008, and briefs were filed on or before December 31, 2008.[1]

During the course of this proceeding, Big Rivers filed numerous motions requesting authority to amend its application. All of those motions have been granted except the one filed on November 25, 2008. That motion, which seeks to provide supplemental and updated information into the record, will be granted.

1998 LEASE AGREEMENT

Big Rivers owns seven coal-fired generating units with a total net capacity of 1,379 MW and one oil/gas-fired combustion turbine with a net capacity of 65 MW. HMPL owns two coal-fired generating units, known as "Station Two," with a net capacity of 310 MW. Since the HMPL units became operational in the 1970s, Big Rivers has operated and maintained them pursuant to a contractual agreement. In general terms, HMPL reserves a quantity of power from Station Two for use on its own system and pays a proportionate share of the costs, while Big Rivers is entitled to the rest of the power and is responsible for the rest of the costs.

In 1998, Big Rivers emerged from a Chapter 11 bankruptcy under the terms of a reorganization plan involving the E.ON Entities. Under that plan, Big Rivers entered into a 25-year lease of its generating facilities (and those it operated under lease from

[1] The AG's brief was titled "Comments."

HMPL) to WKEC.[2] Under the terms of the 1998 lease, WKEC leases and operates Big Rivers' (and HMPL's) generation facilities through 2023, while Big Rivers (and HMPL) retain ownership of their respective generating facilities both during the term of the lease and after its expiration. Since 1998, WKEC has operated and maintained the generating facilities and has been entitled to the power produced by those facilities.

Throughout the lease term, LEM is obligated to supply fixed quantities of power to Big Rivers pursuant to a purchase power agreement. The power supplied by LEM has been sufficient for Big Rivers to meet substantially all of its system requirements. Big Rivers continues to operate its transmission facilities and charges LEM tariffed transmission rates for the delivery of the energy produced by WKEC and consumed by LEM's customers. In addition to purchasing power from LEM, Big Rivers has a long-term agreement to purchase fixed quantities of power from the Southeastern Power Authority ("SEPA").

Under the 1998 lease arrangement, Big Rivers provides power for its three members, excluding Kenergy's requirements to serve the Smelters, through the power purchase agreements with LEM and SEPA. When economically feasible, Big Rivers

[2] Initially, the 1998 lease was conditionally approved in principle by the Commission in Case No. 1997-00204, The Application of Big Rivers Electric Corporation, Louisville Gas and Electric Company, Western Kentucky Energy Corp., Western Kentucky Leasing Corp., and LG&E Station Two Inc. for Approval of Wholesale Rate Adjustment for Big Rivers Electric Corporation and for Approval of Transaction (Ky. PSC April 30, 1998). Due to numerous revisions of the various documents comprising the lease transaction, a subsequent proceeding was established for a determination of whether material changes had been made to the structure of the transaction. The Commission ultimately and unconditionally approved the 1998 lease in Case No. 1998-00267, The Application of Big Rivers Electric Corporation for Approval of the 1998 Amendments to Station Two Contracts Between Big Rivers Electric Corporation and the City of Henderson, Kentucky and the Utility Commission of the City of Henderson (Ky. PSC July 14, 1998).

buys power in wholesale markets to supply its load, and it sells power at a profit into those markets. Even though the Smelters are retail customers of Kenergy, the 1998 lease eliminated Big Rivers and substituted LEM as the wholesale power supplier for the Smelters, with Big Rivers providing the Smelters' supplemental power at market-based rates.

As agreed to by the parties to the 1998 lease, LEM has one contract with Century and one with Alcan to supply power at fixed prices in fixed quantities that provide approximately 70 percent of the Smelters' total loads. The rest of the Smelters' loads are met by power purchased for them by Kenergy on the wholesale market at market-based prices. At times, Big Rivers has been the supplier of this market power. The LEM contract to supply Century expires at the end of 2010 and the contract to supply Alcan expires at the end of 2011. Thereafter, 100 percent of the Smelters' loads will be met by market power purchases.

In addition to leasing its generating units, Big Rivers transferred its responsibility to operate the two HMPL-owned units at Station Two. WKEC ultimately assumed Big Rivers' contractual rights and obligations to perform operation and maintenance service with respect to Station Two. Further, WKEC ultimately assumed Big Rivers' contractual rights and obligations regarding the purchase of power generated from Station Two in excess of the needs of the city of Henderson.

PROPOSED UNWIND TRANSACTION

In early 2003, representatives of E.ON approached Big Rivers to see if it would entertain a proposal to take back operational responsibility for its generating facilities and Station Two, and the corresponding entitlement to all the power generated from those assets, other than the Station Two power reserved by HMPL. Big Rivers viewed this proposal as an opportunity to improve its financial position for the benefit of itself and its members, as a means to obtain financing on more favorable terms, and as a way to better manage its long-term power supply. After analyzing the risks associated with supplying power to the Smelters, including operating and maintaining generation, load concentration, fuel supply, and financial risks, Big Rivers decided to enter into discussions to terminate, or "unwind," the 1998 lease transactions and agreements, with the intent of obtaining significant compensation for assuming those risks.

Big Rivers first negotiated with E.ON and then with the Smelters. In December 2005, Big Rivers, Kenergy, and E.ON announced they had signed a letter of intent to negotiate the Unwind Transaction, and Big Rivers and the Smelters announced agreement on a memorandum of understanding to negotiate a power supply arrangement for the Smelters. On March 26, 2007, Big Rivers and the E.ON Entities executed the Termination Agreement, which established the terms and conditions whereby the 1998 lease transactions and agreements would terminate and unwind.

On December 28, 2007, Big Rivers and the E.ON Entities filed a joint application seeking approval of the Unwind Transaction to position Big Rivers so that it can resume operational control and responsibility of its generating facilities and those at Station Two. More specifically, the application seeks approval of: (1) the Termination Agreement; (2) the transfer of control of Big Rivers' generating units from the E.ON Entities back to Big Rivers; (3) rate and tariff changes; (4) new contracts for service to the Smelters; (5) wholesale power contract extensions; (6) evidences of indebtedness;

and (7) the termination of the pending review of Big Rivers' Integrated Resource Plan ("IRP") and the establishment of November 2010 as the filing date for a new IRP.[3]

The December 28, 2007 application included various documents needed, or descriptions of the documents in process, to accomplish the Unwind Transaction. A financial model to demonstrate the financial feasibility of the Unwind Transaction was also included. The Applicants have submitted multiple amendments to the original application to address a number of significant issues that have developed during the course of this proceeding. One of those issues was a revised forecast of fuel prices which reflected much higher fuel costs through 2013. This necessitated revising the Financial Model to reflect increases in the annual projected fuel costs to be recovered through the Fuel Adjustment Clause ("FAC") component of rates. To offset those higher fuel costs, the E.ON Entities agreed to increase their cash compensation paid at closing for the benefit of both non-Smelter customers and the Smelters.

Another major issue requiring application amendments was the credit downgrading of Ambac Assurance Corporation ("Ambac") to below investment grade. Ambac was providing credit support for the two leveraged leases Big Rivers entered into in 1999 and 2000 with Bank of America ("BoA") and Philip Morris Credit Corporation ("PMCC").[4] Due to the credit downgrade, Big Rivers needed to either provide alternative credit support or terminate the leveraged leases. With financial assistance

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[3] Case No. 2005-00485, The 2005 Integrated Resource Plan of Big Rivers Electric Corporation.

[4] Case No. 1999-00450, Big Rivers Electric Corporation's Application for Approval of a Leveraged Lease of Three Generating Units (Ky. PSC Nov. 24, 1999 and Jan. 28, 2000).

from the E.ON Entities and the Smelters, Big Rivers elected to proceed with the least costly option, which was to buy out both of the leveraged leases. These buy-outs also necessitated revisions to the Financial Model to reflect the need to increase rates to recover the costs of the two buy-outs.

On October 9, 2008, the Applicants filed substantial amendments to the application, including revised transaction documents, a revised financial model, and revised testimony.

UNWIND FINANCIAL MODEL

Big Rivers submitted a financial model to support the reasonableness of the Unwind Transaction. The Unwind Financial Model projects Big Rivers' financial performance through 2023, assuming the Unwind Transaction closes. The model projects annual financial statements, including an income statement, cash flows, and a balance sheet, as well as schedules of projected energy sales, energy production and related costs, fixed costs, capital expenditures and depreciation, taxes, and projected debt service. The Unwind Financial Model also presents detailed projections of wholesale rates to be paid annually by Big Rivers' three member cooperatives and by the Smelters.[5] The Unwind Financial Model has been modified several times to reflect changes as the Unwind Transaction has evolved since the initial application was filed on December 28, 2007.

IMPACT OF BOA AND PMCC BUY-OUTS

As previously discussed, Big Rivers elected to buy out the leveraged leases with BoA and PMCC as the least costly solution to the loss of requisite credit support for

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[5] Direct testimony of Robert S. Mudge, December 28, 2007, Exhibit 9, at 4-5.

those leases. The buy-outs were necessitated solely by the credit crisis, not by the Unwind Transaction. However, they have a significant financial impact on Big Rivers.

The cost to terminate the BoA lease was approximately $6 million, with the buy-out supported by a Cost Share Agreement among Big Rivers, the E.ON Entities, and the Smelters. Under that agreement, the E.ON Entities advanced the full cost of the buy-out. Upon closing the Unwind Transaction, the E.ON Entities will receive a reimbursement of $1 million from Big Rivers and $1 million from the Smelters collectively.[6]

The cost to terminate the PMCC lease was almost $122 million. Big Rivers gave PMCC $109 million in cash and an unsecured note for $12.38 million. The note bears interest at 8.5 percent and is payable upon closing the Unwind Transaction or December 15, 2009, whichever occurs first. The E.ON Entities have agreed that, if the Unwind Transaction closes, they will reimburse Big Rivers one-half of the $121.38 million, plus one-half of a $332,868 shortfall payment that had to be made to CoBank ACB ("CoBank") in conjunction with this buy-out. Thus, if the Unwind Transaction closes, the E.ON Entities will reimburse Big Rivers almost $60.9 million in conjunction with the PMCC buy-out.[7]

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[6] Motion to Amend and Supplement Application, June 11, 2008, Exhibit 5.

[7] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, at 10.

FINANCIAL CONSIDERATION TO BIG RIVERS FROM E.ON ENTITIES

Big Rivers has calculated that the Unwind Transaction will result in its receipt of the following cash and non-cash benefits from the E.ON Entities:[8]

	$ Millions
Cash	387.7
Waiver of Residual Value Payment	141.4
LG&E Rental Income Advance	11.2
Fuel Inventory & Other	51.0
Settlement Promissory Note	15.7
Coleman Scrubber	98.5
SO_2 Allowance & Other	2.0
Leveraged Leases	65.0
Expense Unamortized Marketing Payment	(15.1)
Assurances Agreement Payment	(1.5)
Total	$755.9

The $387.7 million cash payment to Big Rivers will be used for several purposes. Big Rivers will set aside $157 million in an Economic Reserve account to offset future wholesale power cost increases for non-Smelter customers due to increases in fuel, environmental, and other costs. The E.ON Entities' cash payment initially included only $75 million for the Economic Reserve; but, while this case was pending, they agreed to increase that payment by $82 million to offset more recent projections of higher fuel costs.[9] Big Rivers will set aside $35 million as a Transition Reserve to be used as an

[8] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, Exhibit CWB-15.

[9] Second Supplemental Testimony of C. William Blackburn, Exhibit 7, at 3-4.

emergency fund to offset the loss of revenue should one or both Smelters close until alternative buyers are found for the power.[10] Big Rivers will also use funds from the cash termination payment to prepay $140.2 million on its Rural Utilities Service ("RUS") note at the close of the transaction.[11] Big Rivers has also projected that cash termination funds will be used to pay PMCC just over $6 million, which represents one-half of the PMCC loan established with the PMCC buy-out.

The E.ON Entities have agreed to waive the Residual Value Payment for shared incremental and non-incremental capital additions, representing a current value of $141.4 million to Big Rivers.[12] Without this waiver, at the end of the lease Big Rivers would have to pay for its share of certain leasehold improvements constructed by E.ON.[13] Big Rivers estimates that this payment would be approximately $377 million in 2023 at the end of the lease.[14]

Additional non-cash consideration to Big Rivers includes inventories, consisting of fuels, reagents, personal property, and material and supplies, in an amount currently estimated to be $51 million. At closing, the difference between the actual value of the inventories and $55 million will be reflected as an adjustment to the cash

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[10] Direct Testimony of C. William Blackburn, Exhibit 10, at 85.

[11] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, at 12-13.

[12] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, at 47 and Exhibit CWB-15.

[13] Direct Testimony of Michael H. Core, Exhibit 14, at 16.

[14] Transcript of Evidence, December 3, 2008, C. William Blackburn at 140.

consideration.[15] Big Rivers also benefits from a new scrubber, valued at $98.5 million, installed by the E.ON Entities on the Coleman plant.[16]

Significant other non-cash contributions to Big Rivers include: recognition of an LG&E Rental Income Advance of $11.2 million, which represents deferred lease revenue from the E.ON Entities;[17] forgiveness of a Settlement Promissory Note, valued at $15.7 million, owed to the E.ON Entities;[18] and receipt of 14,000 SO_2 allowances with an approximate market value of $2.0 million.[19] Also reflected by Big Rivers, separate and apart from the cash termination payment, is $65 million representing the E.ON Entities' payment of one-half of the costs of the BoA and PMCC buy-outs.[20]

There are also two items identified by Big Rivers which offset the Transaction Benefits: an unamortized $15.1 million marketing payment to the E.ON Entities that was being amortized by Big Rivers over the life of the lease which will now be

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[15] Direct Testimony of C. William Blackburn, Exhibit 10, at 13 and 72.

[16] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, Exhibit CWB-15.

[17] Id.

[18] Direct Testimony of Michael H. Core, Exhibit 14 at 16, and Third Supplemental Testimony of C. William Blackburn, Exhibit 78, Exhibit CWB-15.

[19] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, Exhibit CWB-15.

[20] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, at 10.

expensed;[21] and Big Rivers' assumption of an E.ON Entities liability that will require it to make a $1.5 million Assurances Agreement payment to the Smelters.[22]

SMELTER SERVICE AGREEMENTS

The Smelters' existing service agreements were negotiated in conjunction with Big Rivers' bankruptcy reorganization and its 1998 lease transaction with the E.ON Entities. The Smelters receive about 70 percent of their power requirements from LEM at a fixed price of about $25/MWh, with the rest of their power requirements being supplied by market purchases at prices of $50-$60/MWh. This results in the Smelters paying a blended rate of approximately $35/MWh. Once the existing service agreements expire at the end of 2010 for Century and 2011 for Alcan, the Smelters would have to meet all of their power requirements by market purchases.

When the existing service agreements were negotiated in 1998, the Smelters expected that, by now, market purchases of power would be priced at or below their contract prices. However, due to unforeseen increases in fuel prices, higher environmental costs, and changed market parameters following the California power crisis of 2000-2001, market power purchases are now priced significantly higher than the Smelters' contract prices.

The aluminum smelting process is highly energy-intensive, with the cost of electricity comprising approximately one-third of the cost of production for the Smelters. Unlike many other businesses, the Smelters are unable to simply raise their selling

[21] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, at 48 and CWB-15.

[22] Id.

prices to compensate for higher costs of electricity. Aluminum is a commodity traded worldwide at a market price which is based on global supply and demand. Consequently, significant increases in the price of power for the Smelters would render their operations uneconomic and they would be forced to close. Terminating the Smelters' operations would have a devastating negative economic impact in the area served by Big Rivers. The Smelters directly employ 1,400 workers, who earn an average wage of $54,000 annually.[23] The collective wages, salaries, and benefits paid by the Smelters total $115 million annually.[24] In addition to the direct level of employment by the Smelters, there are approximately 2.5 indirect jobs created by each direct job.[25] Thus, if both of the Smelters were to terminate their operations, close to 5,000 jobs could potentially be lost in the western Kentucky region. The economic impact of these job losses would be devastating to the affected employees from lost wages, as well as to the state from lost income and sales taxes, and to county governments and school districts from lost tax revenues.

Although it would not be possible to guarantee the future financial health of the Smelters, providing them with a long-term supply of power priced at below market prices should enable them to maintain their current competitive positions and continue in operation over the long term. It was for this reason that Big Rivers entered into negotiations with the Smelters on new service agreements that will provide them power at competitive prices while providing protections to Big Rivers and its non-Smelter

[23] Direct Testimony of Paul A. Coomes at 2.

[24] Id.

[25] Id. at 3-4.

customers against the risks inherent in resuming the role of power supplier to the Smelters.

The new service agreements negotiated by Big Rivers and the Smelters provide that Big Rivers will supply 368 MW to Alcan and 482 MW to Century upon payment of the following amounts:

1. A base energy rate of $0.25 per MWh above Big Rivers' wholesale power rate to its members for resale to dedicated delivery point large industrial customers (subject to future adjustment by the Commission) at a 98-percent load factor.

2. An FAC charge.

3. An Environmental Surcharge.

4. A TIER guarantee through 2023, starting at $12.8 million annually in 2009 and increasing to $34.7 million annually in 2021, to ensure that Big Rivers maintains a TIER of 1.24.

5. A non-FAC purchase power adjustment charge.

6. Two annual surcharges consisting of:

    a. Surcharge One – a fixed rate of $0.70 per MWh in 2009-2011, $1.00 per MWh in 2012-2016, and $1.40 per MWh in 2017-2023.

    b. Surcharge Two – a fixed rate of $0.60 per MWh each year, subject to a $200,000 monthly credit for the first 96 months; plus an additional rate of $0.60 per MWh contingent on actual fuel costs exceeding a base line.

The Smelters will also be entitled to an Equity Credit, to be paid by Big Rivers in any year that it earns a TIER in excess of 1.24 and does not elect to make a credit of the excess TIER to all customers.

In recognition of the significantly higher forecast of fuel prices, Big Rivers will make a one-time payment of $7 million to the Smelters, rather than establish an

Economic Reserve account as Big Rivers will do for the non-Smelter customers, in order to moderate the higher fuel costs. Big Rivers has also agreed to make a payment to the Smelters to reflect unanticipated delays in closing the Unwind Transaction. This payment will be based on the higher market power prices the Smelters now pay versus the lower prices to be paid under the new agreements. This payment is estimated to be $2.84 million if the Unwind Transaction closes at the end of March 2009.

The Smelters will also receive substantial compensation from the E.ON Entities. To offset the higher projected fuel costs, the E.ON Entities will deposit $70 million in an escrow account for withdrawal by the Smelters when the FAC exceeds a certain index. The E.ON Entities will deposit another $17.5 million into escrow to offset higher operating costs for the Smelters. The $17.5 million will be dispersed to the Smelters at intervals of 6, 12, and 18 months following the closing of the Unwind Transaction. In addition to these payments, the E.ON Entities have also agreed to make a lump-sum payment to the Smelters upon closing in exchange for their consent to terminate their current power contracts with the E.ON Entities. The amount of this payment has been granted confidential treatment at the request of the E.ON Entities.

These new service agreements also provide the Smelters two levels of load curtailment and a termination of service. The first level of curtailment is for 115 MW, which would essentially cover the power requirements of one potline, and would be allowable for up to 48 months. Under this curtailment, Big Rivers would resell the 115 MW and credit the entire proceeds to the Smelter experiencing the curtailment. The second level of curtailment would be for more than one potline, up to total operations. Under this curtailment, Big Rivers would resell the power not taken by the Smelters and credit the Smelters with the net proceeds but only up to the prices for power under their service agreements. Finally, under a worst-case scenario, the Smelters have the right to permanently close their operations, but only upon one year's advance notice and not before January 1, 2011.

The AG has expressed concern that the Smelters may close down even if the Commission approves the Unwind Transaction.[26] Thus, the AG urges that the Commission "review the proposed transaction with an abundance of caution."[27] The Commission believes that it has proceeded very cautiously and deliberately in this case and has developed an extensive evidentiary record to support the findings and conclusions herein. While the Commission cannot predict the future economic viability of the Smelters, the power prices set forth in the new service agreements should provide a reasonable opportunity for the Smelters to continue operating in Kentucky for the long term and to preserve the jobs and tax base which support the economy of western Kentucky. The Smelters have recently made millions of dollars in new capital investments to improve their production capabilities and efficiencies. While world market prices of aluminum may cause the Smelters to close, these capital investments by the Smelters clearly demonstrate their good faith efforts to maintain their operations in Kentucky for the long term.

UNWIND RATES FOR NON-SMELTER CUSTOMERS

Big Rivers intends to continue to charge its current base rates for wholesale power sold to its three member cooperatives for use by the non-Smelter customers. Big

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[26] AG's Comments at 17-20.

[27] Id. at 20.

Rivers is also requesting to establish a number of rate adjustment clauses to track specific expenses or to flow back as credits the reserve fund accounts and the Smelters' surcharge payments. In addition to these adjustment clauses, Big Rivers has proposed numerous other tariff changes to properly reflect its operations after the Unwind Transaction is completed. All of these changes are set forth in an amended tariff filed October 9, 2008. The Commission finds all of these tariff changes to be reasonable. Big Rivers' proposed rate adjustment clauses are discussed below.

Fuel Adjustment Clause

Big Rivers' purchased power costs for its non-Smelter customers are largely fixed under the terms of its 1998 power purchase agreement with LEM. Consequently, Big Rivers eliminated its FAC upon executing the 1998 lease with the E.ON Entities. With a resumption of control and operation of its generating assets, changes in fuel costs will be an important economic consideration. Therefore, Big Rivers proposes to implement an FAC for all its customers to timely track changes in fuel costs consistent with the Commission's FAC regulations.[28]

Environmental Surcharge

Big Rivers is also proposing to implement for all customers an Environmental Surcharge to recover future environmental costs not included in its existing rates. The Environmental Surcharge is based on recovering the costs of three separate environmental programs (SO_2, NOx, and SO_3) included in the Big Rivers Environmental Compliance Plan ("Environmental Compliance Plan").[29] Big Rivers' proposed

[28] Direct Testimony of C. William Blackburn, Exhibit 10 at 90-92.

[29] Id. at 93-94.

Environmental Compliance Plan and Environmental Surcharge Mechanism were previously reviewed and approved by the Commission last year in Case No. 2007-00460, with implementation conditioned upon closing the Unwind Transaction.[30]

Purchased Power Costs

Big Rivers anticipates incurring costs to purchase power on the wholesale market from time to time. Under the Smelter Service Agreements, the Smelters have agreed to pay for their portion of purchased power costs, not recoverable through the FAC, through a Non-FAC Purchased Power Adjustment ("PPA") mechanism. For the non-Smelter customers, Big Rivers is requesting approval to establish two regulatory accounts, a deferred asset and a deferred liability, to account for any charges or credits related to the portion of the costs of purchased power that are not recoverable under the FAC and are attributable to the non-Smelter customers. Through a tariff called the Regulatory Account Charge, the Non-FAC PPA charges and credits applicable to non-Smelter customers will then be amortized over a period of time after review, and subject to approval, in a general rate case.[31]

Economic Reserve

Upon closing the Unwind Transaction, Big Rivers will use $157 million of the cash contribution from the E.ON Entities to fund the non-Smelter Economic Reserve account. These funds will be flowed back to the non-Smelter customers over approximately five years through a new tariff called the Member Rate Stability

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[30] Case No. 2007-00460, The Application of Big Rivers Electric Corporation for Approval of Environmental Compliance Plan and Environmental Surcharge Tariff (Ky. PSC June 25, 2008).

[31] Direct Testimony of C. William Blackburn, Exhibit 10, at 80-84.

Mechanism ("MRSM"). Through use of the MRSM, Big Rivers predicts that it will be able to offset all cost increases for two years and partially offset cost increases for the following three years. While Big Rivers' rates will increase starting in year three due to cost increases tracked by its FAC and Environmental Surcharge, no general rate increase is projected until 2017.[32]

Unwind Surcredit

Big Rivers is requesting to adopt an Unwind Surcredit that will appear as a credit on the bills of non-Smelter customers. This credit will be equal to the surcharges paid annually by the Smelters to offset increases in fuel costs for non-Smelter customers.[33]

TIER Rebate

Big Rivers is proposing to adopt a TIER-related rebate ("TIER Rebate") to annually flow back to non-Smelter customers, as well as the Smelters, earnings in excess of a 1.24 TIER. The rebate will be made only if Big Rivers determines it is appropriate to do so in a particular year and Commission approval is obtained.

RUS DEBT PAYMENTS

Big Rivers plans to prepay $140.2 million on its RUS note at the close of the transaction utilizing a portion of the cash contribution from the E.ON Entities. Big Rivers will then pay an additional $60 million to RUS on or before 2012 and an additional $200 million no later than January 2016.[34]

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[32] October 2008 Unwind Financial Model, Exhibit 79, page 3, line 17 and page 15, lines 13 and 30.

[33] Direct Testimony of C. William Blackburn, Exhibit 10, at 9 and 80.

[34] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, at 12-13.

BENEFITS OF THE UNWIND TRANSACTION

The Unwind Transaction will produce very significant benefits for Big Rivers, the Smelters, and the non-Smelter customers that would not exist with a continuation of the 1998 lease. While the unique benefits to the Smelters are discussed under the heading "Smelter Agreements," the following discussion details the benefits to Big Rivers, its member cooperatives and all customers.

The first of these benefits is the significant financial contribution to be made by the E.ON Entities to Big Rivers, now valued at $755.9 million. Big Rivers' equity will dramatically improve from a negative $139 million (-11 percent) to a positive $372 million (+26 percent).[35] Big Rivers will also have an investment grade credit rating and will be able to access capital markets when necessary to do so, such as to refinance existing high-interest rate pollution control bonds and to fund future upgrades and replacements of existing facilities. Additionally, Big Rivers' lines of credit, now limited to $15 million, will increase to $100 million with the two new credit agreements now being proposed.

A long-term supply of power will be available for the Smelters at prices below those in the market. This should allow the Smelters to maintain their operations in western Kentucky; preserve hundreds of good-paying jobs; and avoid an erosion of the tax base, which would be devastating to area school districts and local and state governments. Further, the Unwind Transaction will remove the E.ON Entities as the generation operator and supplier to Big Rivers. Although this arrangement has worked

[35] Supplemental Direct Testimony of Michael H. Core, Exhibit 102 at 11, and Exhibit MHC-2.

successfully to date, the relatively fixed prices under the power agreements will likely lead to major disputes and possibly litigation regarding cost responsibility for future environmental and other upgrades. In addition, restoring Big Rivers as the generation operator and supplier will allow future decisions to be made solely in its own best interest, with a renewed emphasis on economic development in western Kentucky.

UNWIND IMPACT ON RURAL CUSTOMERS

The Unwind Transaction will cause rates for non-Smelter customers to rise, not immediately but over time, to projected levels that are higher than would exist under a continuation of the 1998 lease. However, Big Rivers indicated that, absent the Unwind, it will need an immediate rate increase of 20 to 25 percent, although not likely on a permanent basis, to reestablish its financial condition as a result of the expenditure of almost $122 million for the PMCC buy-out. In fact, Big Rivers filed on March 2, 2009 an application to increase its rates by $24.9 million, an increase of 21.6 percent.[36]

One of the major concerns expressed by the AG was the increase in rates for the Rural Customers now projected under the Unwind Transaction. (The Rural Customers consist of all customers on Big Rivers' system except the Smelters and the 20 large industrial customers directly served from substations.) The projected rates for the Rural Customers have increased over the past 12 months due substantially to higher forecasts of fuel prices, leading the AG to conclude that "without further mitigation of the

[36] Case No. 2009-00040, Application of Big Rivers Electric Corporation for a General Adjustment in Rates.

unfavorable rate impacts that are projected to occur," he cannot now support the Unwind Transaction.[37]

While the Commission recognizes and appreciates the AG's concerns relating to the projected rate increases for the Rural Customers, those increases must be considered in light of both the benefits to be achieved by the Unwind Transaction and the level to which rates would rise absent the Unwind Transaction. The record shows that with the Unwind Transaction, Big Rivers' wholesale rates for the Rural Customers are projected to increase incrementally each year from their existing level of \$37.22/MWh to \$48.80/MWh in 2014, representing a weighted average increase of 14.8 percent.[38] Absent the Unwind Transaction, and assuming Big Rivers sells 200 MW to the Smelters at below market rates to help preserve their operations, Rural Customer rates will increase immediately for one year, from \$37.22/MWh to \$44.36/MWh, then alternately decline and increase almost annually, reaching \$45.62/MWh in 2014, representing a weighted average increase of 21.7 percent.[39] Alternatively, absent the Unwind Transaction and with all Big Rivers' excess power sold at market rates, Rural Customer rates will still increase immediately for one year, from \$37.22/MWh to \$44.36/MWh, then decline and later increase to \$40.80/MWh by 2014, representing a weighted average increase of 9.6 percent.[40]

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[37] AG Comments at 28.

[38] Big Rivers Hearing Exhibit #4.

[39] <u>Id.</u>

[40] <u>Id.</u>

The Commission also recognizes that the 1998 lease provides Big Rivers a fixed-price supply of power through 2023 at rates projected to be less than those under the Unwind Transaction. But, at the end of the 1998 lease, Big Rivers would have to pay approximately $377 million to the E.ON Entities for the value of the capital additions to Big Rivers' generating units, a payment that will be eliminated by the Unwind Transaction. The Commission is acutely aware of the current economic and financial crisis now facing our great nation and the people of this Commonwealth. Utility service is a necessity of life, not a luxury, and it needs to be available at the lowest reasonable rates for the Rural Customers of Big Rivers.

Unfortunately, under the Unwind Transaction, a combination of higher fuel costs and exhaustion of the Economic Reserve account in 2013 will result in rate increases for Rural Customers that are simply too high. Thus, Big Rivers' reacquisition of control of its generating units will be consistent with the public interest only if some mitigation is provided to offset the projection of higher rates for the Rural Customers.

Since the Applicants have indicated that time is of the essence in completing the Unwind Transaction, the Commission finds that, rather then delaying this case to allow the Applicants time to fashion a remedy, we will create a reasonable remedy and condition this Order upon the Applicants' acceptance thereof. The E.ON Entities have agreed to reimburse Big Rivers for one-half of the cost of the PMCC buy-out, amounting to approximately $60.9 million.[41] The Commission finds that the E.ON Entities should reimburse Big Rivers 100 percent of that cost, with the additional $60.9 million being held by Big Rivers in a new reserve account to be known as the Rural Economic

[41] Third Supplemental Testimony of C. William Blackburn, Exhibit 78 at 10.

Reserve. This account will be recorded as a regulatory liability and used over 24 months only as a credit against the rates of the Rural Customers upon exhaustion of the Non-Smelter Economic Reserve. This additional $60.9 million should be invested in interest-bearing U.S. Treasury securities, with all interest credited to the Rural Economic Reserve. Big Rivers will need to revise its tariffs to include a new rate mechanism, to be known as the Rural Economic Reserve, to flow back to the Rural Customers the funds in the Rural Economic Reserve Account.

ACCOUNTING TREATMENT

The terms of the Termination Agreement between Big Rivers and E.ON provide for a number of transfers and other issues that require separate accounting considerations.[42] Therefore, Big Rivers is seeking approval for various journal entries and the establishment of certain regulatory accounts.

Big Rivers has proposed specific journal entries to record the assets transferred and the value received from the E.ON Entities, to record Big Rivers' payments to the RUS and the Smelters, to establish deferred liabilities for the Economic Reserve and the Transition Reserve accounts,[43] and to establish both a deferred asset and deferred liability for the non-Smelter, non-FAC PPA.

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[42] Direct Testimony of C. William Blackburn, Exhibit 10, at 71.

[43] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, at Exhibit CWB-14.

Big Rivers intends to currently expense all costs of the BoA and PMCC buy-outs on a "netted" basis. Big Rivers will record a net loss of $16.1 million on its books as a result of this proposed accounting treatment.[44]

FINANCING AND LINES OF CREDIT ISSUES

Big Rivers requests approval to issue two unsecured lines of credit with its traditional supplemental lenders, the National Rural Utilities Cooperative Finance Corporation ("CFC") and CoBank. The CFC line of credit will be for up to $50 million with a five-year term and the funds will be used to finance capital expenditures and for general corporate use. CFC will make loans and issue Letters of Credit upon request up to the $50 million limit. The interest rates on funds drawn on this line of credit will be either the London Interbank Offered Rate ("LIBOR") plus an applicable margin tied to Big Rivers' credit rating or the greater of: (1) the prime rate; or (2) the federal funds effective rate plus 50 basis points.[45]

The CoBank line of credit is also for $50 million with a three-year term and will be used for the same purposes. The interest rates on the CoBank funds will be either the LIBOR plus an applicable margin tied to Big Rivers' credit rating or the prime rate published in the *Wall Street Journal*.[46]

Big Rivers proposes to replace its current Third Restated Mortgage and Security Agreement ("Mortgage") with an Indenture between Big Rivers and a trustee to be named later. To accomplish this transaction, Big Rivers requests approval of both the

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[44] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, at 14.

[45] First Amendment and Supplement to Application filed March 31, 2008, at 4-5.

[46] Id. at 5-6.

Indenture and a Termination of Mortgage Agreement. The Indenture is similar to the Mortgage in many ways, but there is no lien or security interest in cash, most contracts, or stock of any subsidiary. The Indenture will also allow Big Rivers to issue debt without requiring the approval of existing senior secured creditors.[47] Thus, the Indenture should benefit Big Rivers by providing greater operating and financial flexibility.

Big Rivers has also requested authority to issue a Pollution Control Bonds Series 2001A Note to refinance an existing note payable to the County of Ohio, Kentucky ("Ohio County"). The note was issued in consideration of Ohio County's issuance of certain pollution control bonds. The terms of the new note are essentially the same as the original note. This refinancing is necessitated by the replacement of the Mortgage securing the current note with the Indenture in connection with the Unwind Transaction.[48]

Authorization has also been requested to issue an Ambac Municipal Bond Insurance Policy Series 1983 Note. This note will also replace an existing note issued and approved in connection with the BoA and PMCC leases for the repayment of any amounts Ambac must pay under its guarantee to repay certain pollution control bonds issued by Ohio County. The terms of the new note are essentially the same as the original note and are necessitated by the substitution of the Indenture for the Mortgage securing the original note.[49]

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[47] Second Amendment and Supplement to Application filed April 11, 2008, at 2-3.

[48] Id. at 7.

[49] Id.

Big Rivers requests authority to issue a Standby Bond Purchase Agreement Note (Series 1983 Bonds) to replace a note payable to Dexia Credit Local ("Dexia"). The note was issued in connection with the BoA and PMCC leases for the repayment of unpaid principal and interest when due on certain pollution control bonds issued by Ohio County and purchased and held by Dexia. The terms of the new note are essentially the same as the original note and are necessitated by the substitution of the Indenture for the Mortgage securing the original note.[50]

Big Rivers requests approval of the issuance of the Termination of the Third Amended and Restated Subordination, Nondisturbance, Attornment and Intercreditor Agreement. This agreement is necessary to facilitate the termination and release of the existing Intercreditor Agreement.[51] Big Rivers requests approval to enter into the Creditor, Consent, Termination and Release Agreements under which the principal creditors give the necessary consents to terminate the 1998 lease with the E.ON Entities. This agreement terminates both the Mortgage and the existing Intercreditor Agreement.[52] Finally, Big Rivers requests approval of the two letter agreements in which Big Rivers, the Smelters, and the E.ON Entities agreed to the payment terms of the BoA leveraged lease buy-out. Pursuant to these agreements, Big Rivers and the Smelters will each reimburse the E.ON Entities $1 million when the Unwind Transaction is closed.[53]

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[50] Id. at 8.

[51] Id. at 8-9.

[52] Motion to Amend and Supplement Application, October 9, 2008, Exhibit 96.

[53] Motion to Amend and Supplement Application, October 9, 2008, at 8-9.

In addition to the credit arrangement discussed above, Big Rivers identified a number of financing documents that it does not believe require Commission approval but asks the Commission to approve each document should the Commission disagree. Since these documents are integral parts of the Unwind Transaction, the Commission finds it appropriate to approve these documents, except those that are subject to the supervision and control of the RUS.[54]

DEPRECIATION STUDY

Big Rivers' last depreciation study was performed over ten years ago. Big Rivers indicated that its preference was to resume operation of the generating assets prior to conducting a new depreciation study. The Commission finds this approach to be reasonable. However, Big Rivers' proposal to wait another seven years, until 2016, to file a new depreciation study is not reasonable. Depreciation is an important part of a utility's operation, particularly when the utility is not owned by private investors. Since Big Rivers has committed to filing within three years for a general review of its operations and tariffs, a new depreciation study should be submitted as part of the filing, along with an analysis of the impacts of implementing the results of the depreciation study on Big Rivers' financial operations and its rates.

GENERATING PLANT DUE DILIGENCE

One of the conditions precedent to closing the Unwind Transaction is a determination by Big Rivers that each generating plant is in good condition and state of repair. This determination by Big Rivers is of critical importance for a number of

[54] The financing documents to be modified between Big Rivers and RUS are an Amended Consolidated Loan Contract; an RUS 2008 Promissory Note, Series A; and an RUS 2008 Promissory Note, Series B.

reasons. First, there are no guarantees provided by the E.ON Entities as to the condition of the generating plants after the Unwind Transaction is completed. Second, the Smelters' need for a highly reliable power supply at a 98-percent load factor leaves little room for meeting load if there are unplanned outages. Third, since Big Rivers' generation is all relatively low-cost, purchasing replacement power in the event of an unplanned outage will likely be very expensive. Fourth, Big Rivers' ability to meet all of its operational and financial projections is tied to its ability to achieve a relatively high level of reliability from its generating units, including the HMPL Station Two.

The components of Big Rivers' due diligence plan include:

1. Inspection of Operation & Maintenance records at each generation plant;
2. Engineering evaluation of the condition of each plant by Big Rivers and Stanley Consultants;
3. Review of WKEC's operating plans; and
4. Physical testing of operating capability of each generating unit, to be conducted prior to closing.

Big Rivers stated that it does not intend to compile a comprehensive due diligence report just prior to closing the Unwind Transaction because of its longstanding, intimate knowledge of the condition of the generating plants. Big Rivers operated all of the plants up until mid-1998, and it is knowledgeable of all the repairs and maintenance performed since that time. Big Rivers has had its own employees at the generating plants weekly to monitor their operations and it also retained a consulting engineer, Stanley Consultants, to provide annual reports of each unit's repair and maintenance record. Since March 2007, Stanley Consultants has also had personnel at the generating plants full-time. The E.ON Entities have provided Big Rivers and Stanley

Consultants unfettered access to plant maintenance records and relevant financial information compiled since the 1998 lease transaction.

Big Rivers was also actively engaged in the approval and financing of several construction enhancements that were planned and completed by the E.ON Entities over the past ten years. Additionally, it appears that, since leasing the generating units, WKEC has used engineering best-practices in an endeavor to maximize unit reliability and productivity. In fact, for the last ten years, the plants have ranked in either the top quartile or second quartile of generating plants for the standard industry performance metrics of equivalent forced outage rates, equivalent availability factor, and net capacity factors.[55]

The Smelters also retained a consulting engineer, Stone & Webster Management Consultants, Inc. ("Stone & Webster"), to perform a due diligence study. Stone & Webster stated that, even though the base load generating units are 23 to 40 years old, they are in good, if not better, shape than comparable units of similar age and size. Stone & Webster concluded that, with proactive scheduled maintenance, the Big Rivers generation fleet can perform on a reliable basis consistent with industry standards and deliver the expected power output.[56]

The AG's post-hearing comments suggest, for the first time, that the Commission consider hiring its own consulting engineer and conducting an on-site inspection of the generating units.[57] Based on the extensive evidentiary record, including three

[55] Transcript of Evidence, December 2, 2008, Robert Berry, at 184-185.

[56] Smelters' Response to AG's Supplemental Data Request, Item 4.

[57] AG's Comments, at 28.

engineering reports, the Commission finds that there is substantial evidence to demonstrate that the generating plants are in reasonable condition for their age and that they can perform reliably, consistent with industry standards. An on-site visit as suggested by the AG, absent engineering testing and instrumented measurement, would reveal no useful information relative to the capacity of the plants to operate reliably in the future. Although a number of generating plant deficiencies have been identified by the existing engineering reports, those deficiencies have not been shown to impact the reliability of the generating plants. In addition, all necessary actions to correct the deficiencies are scheduled to be performed as part of Big Rivers' 2009-2011 Production Work Plan. Thus, the existence of deficiencies at the generating plants is not a basis upon which to deny approval of the Unwind Transaction.

BIG RIVERS STAFFING LEVELS

The IBEW urges the Commission to adopt the AG's recommendation that Big Rivers be required to maintain "the same level of workforce, with comparable if not better skill and expertise, as it currently does, or notify the Commission if [Big Rivers] has concluded it would be imprudent to do so, stating the reason why [Big Rivers] believes it to be imprudent."[58]

In response to this recommendation, Big Rivers has provided a commitment to continue to employ the level of workforce necessary to safely and professionally operate its facilities. Big Rivers criticizes the AG's workforce recommendation, arguing that with such a requirement the Commission would have to exercise its jurisdiction to review the prudence of every workforce reduction but remain indifferent to any staffing-level

[58] Direct Testimony of David Brevitz, at 52.

increases. Big Rivers maintains that the commitment it has provided is consistent with the Commission's jurisdiction and representative of the expectations that the Commission and Big Rivers' customers should have of Big Rivers.

The Commission finds it reasonable in this case, where Big Rivers seeks to reacquire control of assets it previously controlled, to allow Big Rivers the flexibility to determine its future workforce levels, consistent with good utility practice. Big Rivers is organized as a cooperative and is owned by its three member distribution cooperatives that, in turn, are owned by their 110,000 electric customers. There is no reason to believe that Big Rivers will be driven by a profit motive to reduce its workforce below the levels necessary to maintain highly reliable service expected and needed by all of the 110,000 customers it serves.

OPEN ISSUES

HMPL Consent

The AG asserts that there are a number of outstanding conditions that should be brought to a conclusion before the Commission rules on the reasonableness of the Unwind Transaction. One of those conditions is the absence of the requisite consent to the Unwind Transaction by HMPL. Under the terms of the 1998 lease transaction, any termination of the lease requires the affirmative consent of HMPL. Although Big Rivers and the E.ON Entities have been engaged in discussions with HMPL for over three years in an effort to obtain HMPL's consent, no agreement has yet been reached. The AG argues that, until HMPL consents to the Unwind Transaction, the Commission cannot approve the documents that require HMPL's signature because such documents are merely proposals and not yet agreements.

HMPL is a party to this case. It filed responses to requests for information and attended informal conferences and the hearing, but did not file testimony. HMPL claims that its two generating units that comprise the Station Two complex have not been properly operated and maintained by the E.ON Entities under the lease and that the E.ON Entities should be responsible for paying approximately $13.5 million toward the cost of future maintenance and repairs. HMPL bases its claim on the engineering reports from its own consulting engineers, Exothermic Engineering Co., LLC ("Exothermic"), as well as those from Big Rivers' consulting engineers, Stanley Consultants; and the Smelters' consulting engineers, Stone & Webster. HMPL's consultant, Exothermic, performed a condition assessment ("Exothermic Report") dated October 30, 2007. The Exothermic Report consists of "a visual condition assessment as opposed to a technical condition assessment."[59] The Exothermic Report was a visual inspection through photographs of the external condition of the plant and did not include any testing or instrumented measurement.[60] HMPL also asserts that, under the terms of its 1970 Station Two contracts with Big Rivers, the payments HMPL receives for energy and capacity reserved but not taken ("excess energy") are insufficient and need to be increased.

The Applicants acknowledge that the external condition of Station Two needs corrective action, but they assert that there are no known deficiencies that would adversely affect the reliability of those units. Stone & Webster concluded that, although Station Two has been in service for over 30 years, the units, for the most part, have

[59] Exothermic Report at 3.

[60] Id.

been reliable and have experienced the usual maintenance history of other units of this vintage.[61] Stone & Webster further stated that those generators were in good condition during their 2003 and 2004 overhauls and that their next scheduled overhauls will be in 2011 and 2012.

The Applicants have offered a number of financial incentives to HMPL to obtain its consent to the Unwind Transaction. The incentives coming from the E.ON Entities include the payment of $1 million for HMPL's consent, $3 million for future repairs at Station Two, and the reimbursement of HMPL's fees incurred in connection with the Unwind Transaction, up to $1.4 million. Big Rivers has also agreed to increase the payments to HMPL under their 1970 Station Two contracts from $1.50/MWh to $2.50/MWh for the excess energy, even though there is no provision in those agreements for renegotiating that payment. Big Rivers has also committed that it will resubmit for Commission review any agreement entered into with HMPL that would provide a level of compensation from Big Rivers in excess of what it has already offered.

The Commission finds no merit in the AG's argument regarding HMPL. Big Rivers is a jurisdictional utility subject to our regulation. The Unwind Transaction includes changes in rates and the issuance of evidences of indebtedness and other financing documents, all of which are subject to our review and approval. Big Rivers' agreements with HMPL are integral parts of the Unwind Transaction. In connection with the 1998 lease transaction, we reviewed and approved the documents to which Big Rivers and HMPL were parties, including the amendment to the Station Two contracts.

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[61] Stone & Webster Report, filed March 11, 2008, at 5.

Although HMPL has not yet agreed to the current amendments now proposed by Big Rivers, the Commission has reviewed those amendments and finds that they are reasonable. In the event that there are any revisions to those amendments that would increase the amount of compensation to be paid by Big Rivers to HMPL, Big Rivers has committed to resubmit the revisions for our additional review. Under these circumstances, we find no basis to delay or defer a decision on these documents.

The record shows that numerous repairs of an exterior nature are needed to Station Two, including many in the categories of both safety and cosmetic. However, there is no credible evidence that the reliability of those units is presently compromised as a result of inadequate or improper maintenance or repairs. In addition, the uncontradicted evidence of record supports our finding that the compensation to be provided to HMPL by the Applicants is reasonable. This finding is based on the physical condition of Station Two, as well as the fact that, but for the Unwind Transaction, HMPL would have no right to any additional payments from Big Rivers for excess energy. Further, to the extent that HMPL believes that E.ON has not properly maintained Station Two, terminating the E.ON lease now rather than waiting until it expires in 14 years will remove E.ON from the picture and restore operational control of Station Two to Big Rivers.

Big Rivers' Credit Rating

Another of the conditions precedent to closing the Unwind Transaction is that Big Rivers have an investment grade credit rating so that it will be able to issue public debt at reasonable costs in the future.[62] The AG argues that, since Big Rivers is in the

[62] Application filed on December 28, 2007, Exhibit 3, at 64 of 622.

process of obtaining, but has not yet received, a credit rating for its debt, the Commission should defer a decision on the Unwind Transaction until a credit rating is obtained. The Applicants assert that an investment grade credit rating is just one of dozens of conditions precedent to closing the Unwind Transaction; that satisfaction of all such conditions, including approval of the Commission, should be pursued simultaneously; and that any material changes to the terms of the Unwind Transaction (or additional compensation from Big Rivers to HMPL) after the date of approval by the Commission will be resubmitted to the Commission for its review.

The Commission well recognizes that an investment grade credit rating for Big Rivers is a linchpin of the financial model. Absent such a credit rating, neither Big Rivers' proposed financing plans nor the Unwind Transaction will be successful. However, despite the importance of the credit rating to the Unwind Transaction, we find no need to defer our decision in this case until after that credit rating has been issued. The Commission frequently reviews transactions before the requisite approvals from other entities have been obtained and before all conditions precedent have been satisfied. In these situations, if the Commission finds that the transaction should be approved and that there are conditions precedent which are of critical importance, the transaction can be approved with appropriate conditions to insure that the conditions precedent are satisfied.[63] In recognition of both the Applicants' desire to complete the

[63] Case No. 2000-00095, Joint Application of PowerGen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger, Order dated May 15, 2000, and Case No. 2001-00104, Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of PowerGen plc, Order dated August 6, 2001.

Unwind Transaction as soon as reasonably possible and the Commission's finding that there is no reason to delay its review, the approvals granted by this Order will be conditioned upon Big Rivers receiving the investment grade credit rating as specified in the Transaction Termination Agreement.

ADDITIONAL TRANSACTION CONDITIONS

As of April 3, 2008, the AG recommended approval of the Unwind Transaction, but on a provisional basis and with certain conditions, since there were still unresolved issues, including the consent from HMPL and the credit ratings. The AG enumerated 17 recommended conditions that should be imposed on Big Rivers or other parties if the Commission approves the Unwind Transaction. Subsequently, the AG's position changed. As of November 21, 2008, the AG no longer recommended approval of the Unwind Transaction, but he still recommended consideration of his conditions if the Commission decided to approve the Unwind Transaction.

At an informal conference held at the Commission's offices on June 19, 2008, Big Rivers presented a response to the AG's recommended conditions and to a number of other issues identified through discovery. That response included numerous commitments that were intended to satisfy many of the AG's conditions and the other issues identified.

Based on a review of the AG's recommended conditions and the response thereto, the Commission finds that most of the commitments offered by Big Rivers are, in general, reasonable and should be adopted with some modifications and additions. A list of those revised commitments is attached hereto as Appendix A.

INTEGRATED RESOURCE PLAN

In late 2005, Big Rivers filed an IRP based on the assumption that it would continue to purchase its power supply from the E.ON Entities.[64] Shortly thereafter, Big Rivers requested, and the Commission allowed, that case to be held in abeyance due to Big Rivers' expectation that it would cease purchasing power and regain operating control of its generating units. Big Rivers now requests that case be terminated since the reacquisition of its generation renders the information in that IRP obsolete and it has not yet initiated a new load forecast. Big Rivers commits to filing a new IRP no later than November 2010.

The Commission finds Big Rivers' request to be reasonable. Its new IRP should be filed by November 15, 2010 to allow sufficient time for the preparation of a new load forecast and to properly reflect the reacquisition of generation. However, the Commission believes that certain critical information required to be included in an IRP needs to be filed on an interim basis for review pending the November 15, 2010 filing of a complete new IRP. This information, which needs to be filed by September 15, 2009 and again by March 15, 2010, is set forth in 807 KAR 5:058, Section 8(2). In addition, the assessment of economic opportunities for coordination with other utilities, which is required by Section 8(2)(c), must include, but not be limited to, transmission lines and other infrastructure, as well as generating units. The "other utilities" to be considered in this assessment must include, but not be limited to, Tennessee Valley Authority and E.ON and its subsidiaries. Further, these interim filings must include specific details of

[64] Case No. 2005-00485, The 2005 Integrated Resource Plan of Big Rivers Electric Corporation.

the economic development efforts by Big Rivers to benefit the service area of its three member cooperatives.

OUTSTANDING PETITIONS

Pending before the Commission are a number of petitions filed by Big Rivers requesting confidential protection of information related to a negotiated payment from the E.ON Entities to the Smelters and Big Rivers' lines of credit. Also pending is a Big Rivers petition for rehearing of the Commission's earlier denial of confidentiality of information relating to the lines of credit and the terms of Big Rivers' agreement with BoA regarding the leveraged lease buy-out.

Confidentiality was previously granted by letter dated April 29, 2008 to the details of the E.ON Entities' payment to the Smelters. Therefore, for the reasons set forth in that letter, which is incorporated herein by reference, confidentiality is granted to that portion of Big Rivers' December 12, 2008 petition relating to the E.ON Entities' payment to the Smelters.

With respect to the lines of credit, Big Rivers requests to withhold from public disclosure the details of the terms and conditions of its proposed lines of credit with CFC and CoBank, including the costs and fees to be paid to each lender for each line of credit. Big Rivers maintains that the public disclosure of this information will result in competitive injury by allowing other lenders to know what it is willing to pay for a line of credit. However, Big Rivers acknowledged that its proposed CFC and CoBank lines of credit will be in place for five and three years, respectively, and that, "[t]he market always has an impact on how [lines of credit] are structured."[65] Thus, as market

[65] Transcript of Evidence, December 3, 2008, C. William Blackburn, at 88.

conditions change over time, it is reasonable to expect that the terms for a line of credit will also change. As a public utility, the terms and conditions of its financings should be publicly available except in extraordinary circumstances where there is a clear and strong showing of competitive injury. Big Rivers has not satisfied that burden of proof on this issue. Therefore, the Commission will affirm its earlier decision to deny confidentiality for the terms of Big Rivers' lines of credit. Big Rivers' petition for rehearing is denied, as well as its November 25, 2008 and December 1, 2008 confidentiality petitions, and that portion of its December 12, 2008 confidentiality petition, all relating to its lines of credit.

With respect to the terms of the BoA leveraged lease buy-out, all of the significant terms of that transaction are already publicly available in the record of this case.[66] Therefore, that portion of Big Rivers' petition for rehearing relating to the BoA buy-out is denied.

OBSOLETE COMMITMENTS

The Applicants have also requested to be relieved from certain commitments that were imposed in connection with the Commission's approval of the 1998 lease or were subsequently imposed but are relevant only to that transaction. The commitments which Big Rivers seeks to eliminate arise from the Commission's April 30, 1998 Order in

[66] Third Supplemental Testimony of C. William Blackburn, Exhibit 78, CWD-9.

Case No. 1997-00204,[67] and July 14, 1998 Order in Case No. 1998-00267,[68] requiring a 50/50 sharing methodology for the reporting and recovery of unforeseen changes in transmission costs due to the Smelters' load, requiring Big Rivers to file annual updates to its 1998 lease transaction financial model, requiring Big Rivers to file a report of its arbitrage sales and other sales, and requiring Big Rivers to file an annual report on its plant maintenance. The E.ON Entities' commitments that are requested to be eliminated were imposed in conjunction with its prior mergers, and include merger commitment nos. 5, 6, and 9 relating to the PowerGen merger case,[69] and merger commitment nos. 40, 41, and 44 in the E.ON merger case.[70] The Commission agrees that these merger commitments will no longer be relevant after the Unwind Transaction is completed. Therefore, these commitments will be eliminated upon closing the Unwind Transaction.

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[67] Case No. 1997-00204, The Application of Big Rivers Electric Corporation, Louisville Gas and Electric Company, Western Kentucky Energy Corp., Western Kentucky Leasing Corp., and LG&E Station Two, Inc. for Approval of Wholesale Rate Adjustment for Big Rivers Electric Corporation and for Approval of Transaction.

[68] Case No. 1998-00267, The Application of Big Rivers Electric Corporation for Approval of the 1998 Amendments to Station Two Contracts Between Big Rivers Electric Corporation and the City of Henderson, Kentucky and the Utility Commission of the City of Henderson.

[69] Case No. 2000-00095, Joint Application of PowerGen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company, for Approval of Merger (Ky. PSC May 15, 2000).

[70] Case No. 2001-00104, Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of PowerGen plc (Ky. PSC Aug. 6, 2001).

SUMMARY OF FINDINGS

The Commission finds that the change in control of generating units from the E.ON Entities to Big Rivers is for a proper purpose and is consistent with the public interest, subject to Big Rivers' accepting the commitments set forth in Appendix A and the E.ON Entities accepting the commitment set forth in Appendix B. Within seven days of the date of this Order, the chief executive officers of Big Rivers and of the E.ON Entities should file written notices stating that they either accept and agree to be bound by or reject their respective commitments as set forth in Appendices A and B. The Termination Agreement and all other transaction documents, new power contracts, the rate and tariff changes, and the financing documents, filed in support of the Unwind Transaction and listed in Appendix C, are reasonable and should also be approved subject to the Applicants' acceptance of the commitments.

The Commission further finds that the issuance of the proposed evidences of indebtedness, notes, and Indenture as set out in Big Rivers' application is for lawful objects within the corporate purposes of Big Rivers' utility operations, is necessary and appropriate for and consistent with the proper performance of its service to the public, will not impair its ability to perform that service, is reasonably necessary and appropriate for such purposes, and should therefore be approved.

IT IS THEREFORE ORDERED that:

1. The change in control of generating units from the E.ON Entities to Big Rivers is approved subject to Big Rivers' receipt of an investment grade credit rating and the filing within seven days of the date of this Order of written notices signed by the chief executive officers of Big Rivers and the E.ON Entities that each agrees to accept

and be bound by their respective commitments set forth in Appendices A and B to this Order.

2. All of the documents relating to the Unwind Transaction, as listed in Appendix C hereto, including but not limited to the Termination Agreement, the new power agreements, the financing documents, and the revised tariffs, are approved subject to the filing of the notices of acceptance of commitments referenced in Ordering Paragraph No. 1.

3. In the event that both Big Rivers and the E.ON Entities file a notice of acceptance of commitments as described in Ordering Paragraph No. 1, the Applicants shall, individually or jointly, file with the Commission reports on the status of closing the Unwind Transaction, with the first report due 45 days after the date of this Order and subsequent reports due every 15 days thereafter until the closing takes place.

4. Big Rivers shall, upon closing the Unwind Transaction, establish the journal entries and regulatory accounts, including, but not limited to, the regulatory liability to establish the Rural Economic Reserve, and shall deposit $60.9 million in the Rural Economic Reserve, all in accordance with the findings above.

5. Big Rivers shall, within 20 days of the date of closing the Unwind Transaction, file with the Commission its revised tariff sheets, including, but not limited to, a rate mechanism to implement the Rural Economic Reserve, as approved herein, showing their date of issue and that they were issued by authority of this Order.

6. Big Rivers shall file a new IRP no later than November 15, 2010 and it shall file, on September 15, 2009 and again on March 15, 2010, reports setting forth the

information required by 807 KAR 5:058, Section 8(2), and the details of its economic development activities as more fully described in the findings above.

7. Within 20 days of the date of closing the Unwind Transaction, Case No. 2005-00485, which was established to review Big Rivers' 2005 IRP, shall be terminated.

8. Big Rivers' November 25, 2008 motion to amend, and that portion of its December 12, 2008 confidentiality petition relating to the E.ON Entities' payment to the Smelters, are granted.

9. The Commission's earlier denial of confidentiality to Big Rivers' information related to its lines of credit and the BoA buy-out is affirmed and Big Rivers' rehearing request for reversal of those decisions is denied. Big Rivers' pending confidentiality petitions, filed on November 25, 2008 and December 1, 2008, and that portion of its December 12, 2008 petition, all relating to its lines of credit, are denied.

10. Big Rivers is authorized to issue evidences of indebtedness, issue and sell notes, and enter into the Indenture, all upon the terms set forth in its application.

11. Big Rivers is authorized to use the proceeds arising from the issuance and sale of the subject evidences of indebtedness and notes for only the lawful purposes set forth in its application.

12. Big Rivers shall, within 30 days of the date of each issuance, file with the Commission a statement setting forth the date of issuance and terms of the evidences of indebtedness, notes, and Indenture authorized herein, including the interest rate.

Nothing contained here shall be construed as a finding of value for any purpose or as a warranty on the part of the Commonwealth of Kentucky or any agency thereof as to the securities authorized herein.

Done at Frankfort, Kentucky, this 6th day of March, 2009.

By the Commission

ATTEST:

Executive Director

Case No. 2007-00455

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2007-00455 DATED MARCH 6, 2009

1. Big Rivers commits to use the actual expenses reported by WKEC to calculate the fuel adjustment clause charges and the environmental surcharge for the period until Big Rivers' actual costs are available.

2. Big Rivers commits that the Economic Reserve will be funded at closing of the Unwind Transaction by an amount no less than $157 million.

3. Big Rivers commits to not sell SO_2 allowances in its inventory (excluding the 14,000 SO_2 allowances acquired in conjunction with the Unwind Transaction) unless the sale is cost-effective based on a written policy which reflects short- and long-term allowance needs and prices.

4. Big Rivers will account on its books for emission allowances it acquires in the Unwind Transaction in accordance with the RUS Uniform System of Accounts.

5. Big Rivers commits to not close the Unwind Transaction until the Commission has reviewed and approved any change to the Station Two Contract amendments filed on October 9, 2008, if the change will result in: (a) Big Rivers providing, directly or indirectly, to HMPL, the city of Henderson, or a third party, anything of value that differs in form, substance, or amount from the value to be provided by Big Rivers under the amendments filed on October 9, 2008; or (b) the need to revise the Unwind Financial Model to properly reflect the change to the amendments filed on October 9, 2008.

6. Big Rivers commits to maintaining a sound and constructive relationship with those labor organizations that may represent certain employees of WKEC.

7. Big Rivers commits to bargain in good faith with IBEW during any collective bargaining sessions.

8. Big Rivers commits to continue to employ in the conduct of its business the level of workforce required to safely and professionally operate its facilities.

9. Big Rivers commits to finalize its due diligence on the generating facilities and sites using all resources available to it. Big Rivers also commits to not waive any of its rights under the Termination Agreement, Sections 10.3(dd) or 10.3(ee), to require that the generating facilities be in good condition and that there is a proper demonstration of their capability.

10. Big Rivers commits that, within 24 hours of closing the Unwind Transaction, a written notice will be filed with the Commission setting forth the date of closing.

11. Big Rivers commits to file a report with the Commission within 10 days after the closing of the Unwind Transaction stating that all of the conditions precedent to the closing of the Unwind Transaction have been satisfied or, if any of the conditions have been waived, the terms on which each waiver was granted.

12. Big Rivers commits that, within 3 years of closing the Unwind Transaction, Big Rivers will file with the Commission for a general review of its financial operations and its tariffs. Big Rivers also commits to include with that filing a new depreciation study and an analysis of Big Rivers' financial condition and rates assuming the study's results are implemented.

13. Big Rivers commits that it will file an IRP, in accordance with the Commission's regulations, for the Big Rivers system no later than November 15, 2010.

Big Rivers also commits to file by September 15, 2009 and again by March 15, 2010, the information listed in 807 KAR 5:058, Section 8(2) and the details of economic development activities, all as specified in the IRP section of the attached Order.

14. Big Rivers commits, in connection with the filing of its IRPs, to advise the Commission of any material changes to the RUS's criteria for the financing of both new coal-fired plants, and existing coal-fired plants, on a timely basis. In the event of any such changes, Big Rivers commits to supply a plan for assessing the impact and ramifications, if any, and how Big Rivers will address those changes.

15. Big Rivers commits to filing with the Commission, within 60 days of closing the Unwind Transaction and by April 30 of each year thereafter, through the date on which it files a case for a general adjustment of its rates, and thereafter as may be required by the Commission, the "Big Rivers New Financial Model." The Big Rivers New Financial Model will supplement the Big Rivers monthly filing of its RUS Form 12, its Financial and Statistical Report (Annual Report) and the Big Rivers annual report (containing audited financial statements), all of which are filed with the Commission. The Big Rivers New Financial Model will contain actual financial results for the prior year, the current year's budget, three forecasted years beyond the current year, and an explanation of all assumptions.

16. Big Rivers commits to fund, initiate and maintain a risk management plan and program, which would include the ability to identify and address the impact of contingencies including, but not limited to, fuel prices, cost exposure for environmental remediation programs (both existing and contemplated), and any other material risks pertaining to Big Rivers. Big Rivers commits to have the risk management plan and program in effect no later than 3 months after the date of closing the Unwind Transaction

and to be prepared, in connection with the review of its financial operations in 3 years, and again in its next application for a general adjustment in rates, to respond to questions regarding identified risks and steps taken under its Risk Management program to address or mitigate those risks.

17. Big Rivers commits to provide to the Commission, upon its request and in 3 years in connection with the review of Big Rivers' financial operations, a copy of any reports, recommendations or other documents produced by the Coordinating Committee or either Smelter, and that is provided to the Big Rivers board of directors.

18. Big Rivers commits, in connection with the review of its financial operations in 3 years, to advise the Commission in the event of any material changes in its collective bargaining agreements with labor unions.

19. Big Rivers commits to advise the Commission and the Attorney General's Office of any material changes in the evidences of indebtedness that comprise its financing arrangements, on a timely basis.

20. Big Rivers commits to advise the Commission of any material changes to the smelter-related retail and wholesale contracts, on a timely basis.

21. Big Rivers commits to timely advise the Commission and the Attorney General's Office in the event of any material changes in its agreements with HMPL after the closing of the Unwind Transaction.

22. Big Rivers commits to complete construction of the transmission system additions and improvements for which the Commission issued a Certificate of Public Convenience and Necessity in P.S.C. Case No. 2007-00177, and commits to advise the Commission and the Attorney General's Office on a timely basis of the date those transmission facilities become fully operational and of any material events related to the

Big Rivers transmission system that impact Big Rivers' long-term ability to wheel excess power to its border for sale into other markets.

23. Big Rivers commits that its chief executive officer and relevant members of its senior staff will meet informally with the Commission and the Attorney General's Office at least annually to advise them regarding: (i) general operations and finances of Big Rivers; (ii) transition activities; (iii) regulatory and industry developments that may affect Big Rivers in the future; (iv) the status of Big Rivers' plans for addressing the $200 million reduction in the Maximum Allowed Balance in the RUS 2008 Promissory Note, Series A before the end of 2015; (v) changes in the competitiveness of the Smelters in the world aluminum market of which Big Rivers is aware and which could materially affect the commitment of the Smelters to continue operations; and (vi) the work of the Coordinating Committee.

24. Big Rivers commits that a Rural Economic Reserve account will be established and funded at closing of the Unwind Transaction in an amount no less than $60.9 million to be used exclusively to credit the bills rendered to the Rural Customers over a period of 24 months commencing upon depletion of all funds in the Economic Reserve. All funds in the Rural Economic Reserve shall be invested in interest-bearing United States Treasury notes, with all interest earned credited to the Rural Economic Reserve. Big Rivers commits that no funds in the Rural Economic Reserve escrow account will be spent, pledged, or otherwise used for any purpose other than as credits on the future bills of Rural Customers in accord with the terms of this commitment.

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2007-00455 DATED MARCH 6, 2009

The E.On Entities commit to pay to Big Rivers at the time of closing the Unwind Transaction an additional $60.9 million in cash to reimburse Big Rivers for one-half of the cost of the PMCC buy-out that, but for this commitment, would be the responsibility of Big Rivers.

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2007-00455 DATED MARCH 6, 2009

AGREEMENTS AND DOCUMENTS TO BE APPROVED

1. Termination Agreement (including all related documents and transactions and termination of all the agreements from the 1998 Transactions as contemplated in the Termination Agreement); Approval of the First Amendment to Transaction Termination Agreement; Approval of Letter Agreement; Approval of Second Amendment to Transaction Termination Agreement; Approval of Third Amendment to Transaction Termination Agreement.

2. Generation Dispatch Support Services Agreement.

3. Information Technology Support Services Agreement.

4. Station Two Agreements and Amendments, including:

a. Second Amendatory Agreement;

b. Amendments to 1970 Station Two Power Sales Contract;

c. Station Two Termination and Release Agreement;

d. Station Two G&A Allocation Agreement; and

e. Agreement for Assignment of Responsibility for Complying with Reliability Standards.

5. Alcan Wholesale Agreement, Retail Agreement, Lockbox Agreement, and Guaranty.

6. Century Wholesale Agreement, Retail Agreement, Lockbox Agreement, and Guaranty.

7. Smelter Coordination Agreements.

8. Amendments to Big Rivers' Member Wholesale Power Contracts.

9. All of Big Rivers' Proposed Tariff Revisions, Including the Revised Open Access Transmission Tariff.

10. Revolving Line of Credit Agreement between Big Rivers Electric Corporation and National Rural Utilities Cooperative Finance Corporation.

11. Revolving Credit Agreement by and between Big Rivers Electric Corporation and CoBank ACB, including note by and between Big Rivers Electric Corporation and CoBank ACB.

12. PCB Series 2001A Note from Big Rivers Electric Corporation to the County of Ohio, Kentucky.

13. Ambac Municipal Bond Insurance, Policy Series 1983 Note from Big Rivers Electric Corporation to Ambac Assurance Corporation.

14. Standby Bond Purchase Agreement Note (Series 1983 Bonds), from Big Rivers Electric Corporation to Dexia Credit Local, acting by and through its New York Branch.

15. Termination of Third Amended and Restated Subordination, Nondisturbance, Attornment and Intercreditor Agreement among (a) Big Rivers Electric Corporation; (b) LG&E Energy Marketing Inc., and Western Kentucky Energy Corp.; (c) The United States of America, acting through the Administrator of the Rural Utilities Service; (d) Ambac Assurance Corporation; (e) National Rural Utilities Cooperative Finance Corporation; (f) Dexia Credit Local, New York Branch; (g) U.S. Bank Trust National Association, as trustee under the Trust Indenture dated as of August 1, 2001;

(h) PBR-1 Statutory Trust; (i) PBR-2 Statutory Trust; (j) PBR-3 Statutory Trust; (k) FBR-1 Statutory Trust; (l) FBR-2 Statutory Trust; (m) PBR-1 OP Statutory Trust; (n) PBR-2 OP Statutory Trust; (o) PBR-3 OP Statutory Trust; (p) FBR-1 OP Statutory Trust; (q) FBR-2 OP Statutory Trust; (r) Bluegrass Leasing; (s) Bank of America Leasing Corporation; (t) AME Investments, LLC; (u) CoBank, ACB; and (v) Ambac Credit Products, LLC.

16. Termination of Third Restated Mortgage and Security Agreement among (a) Big Rivers Electric Corporation; (b) The United States of America, acting through the Administrator of the Rural Utilities Service; (c) Ambac Assurance Corporation; (d) National Rural Utilities Cooperative Finance Corporation; (e) Dexia Credit Local, New York Branch; (f) U.S. Bank Trust National Association, as trustee under the Trust Indenture dated as of August 1, 2001; (g) PBR-1 Statutory Trust; (h) PBR-2 Statutory Trust; (i) PBR-3 Statutory Trust; (j) FBR-1 Statutory Trust; (k) FBR-2 Statutory Trust; and (l) Ambac Credit Products, LLC.

17. Creditor Consent, Termination and Release Agreement by and among (a) Big Rivers Electric Corporation; (b) E.ON U.S. LLC, LG&E Energy Marketing Inc., and Western Kentucky Energy Corp.; (c) The United States of America, acting through the Administrator of the Rural Utilities Service; (d) Ambac Assurance Corporation; (e) National Rural Utilities Cooperative Finance Corporation; (f) Dexia Credit Local, New York Branch; (g) U.S. Bank Trust National Association, as trustee under the Trust Indenture dated as of August 1, 2001; (h) PBR-1 Statutory Trust; (i) PBR-2 Statutory Trust; (j) PBR-3 Statutory Trust; (k) PBR-1 OP Statutory Trust; (l) PBR-2 OP Statutory Trust; (m) PBR-3 OP Statutory Trust; (n) Bluegrass Leasing; (o) Bank of America

Leasing Corporation; (p) AME Investments, LLC; (q) CoBank, ACB; (r) AME Asset Funding, LLC; and (s) Ambac Credit Products, LLC.

18. Amendment of Operating and Support Agreement (Wilson Operating Agreement).

19. Letter Agreements regarding "Funding of Certain Amounts to be Paid to the Bank of America" and "Payment Regarding the Buy-Out of the Bank of America."

20. Indenture from Big Rivers Electric Corporation, Grantor to **[Name of Trustee].**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

ORDER

On February 1, 2010, Big Rivers Electric Corporation ("Big Rivers") tendered an application requesting approval to transfer functional control of its transmission system to the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). Intervenors in this matter are the Midwest ISO, Kentucky Industrial Utility Customers, Inc. ("KIUC"), and the Attorney General of the Commonwealth of Kentucky (collectively, "Intervenors"). A procedural schedule was established by Order dated March 15, 2010, which provided for two rounds of discovery on Big Rivers' application, intervenor testimony, one round of discovery on the intervenor testimony, and a formal public hearing.[1]

On September 14, 2010, Big Rivers and the Intervenors submitted a unanimous Stipulation and Agreement ("Stipulation") pursuant to which the Intervenors agreed that they did not oppose Big Rivers' membership in the Midwest ISO. The hearing was held

[1] Pursuant to a motion by the Midwest ISO, the procedural schedule was later modified to allow for the scheduling of an informal conference, which was held on July 7, 2010.

on September 15, 2010, and responses to post-hearing information requests have been received, as well as post-hearing briefs. This matter now stands submitted for decision.

BACKGROUND

Big Rivers, a not-for-profit generation and transmission electric cooperative, owns and operates both electric generation and transmission facilities. It supplies the wholesale electricity requirements of its three member distribution cooperatives, Meade County Rural Electric Cooperative Corporation, Jackson Purchase Energy Corporation, and Kenergy Corp. (collectively, "Members"), who provide retail electric service to roughly 110,000 customers in 22 western Kentucky counties. Big Rivers requests approval to join the Midwest ISO in order to enable it to meet the contingency reserve requirement of the North American Electric Reliability Corporation ("NERC") as approved by the Federal Energy Regulatory Commission ("FERC"). Meeting this contingency reserve standard is an operational reliability necessity as well as a legal requirement. Failure to meet the NERC contingency reserve standard could result in Big Rivers being assessed penalties of up to $1 million per day.

Historically, Big Rivers met NERC's contingency reserve requirement through membership in different reserve-sharing arrangements, most recently the Midwest Contingency Reserve Sharing Group ("MCRSG"), which expired December 31, 2009. During 2009, Big Rivers investigated various alternatives to enable it to continue to meet the NERC contingency reserve standard, including other sharing arrangements, purchasing power, investigating the potential for significant demand interruptions by the largest customers on its system, and operating its generating units at reduced capacity levels. Upon determining that these options were economically or legally infeasible, or that there was insufficient time in which to implement them, on November 20, 2009, Big Rivers' Board of Directors approved initiating the process to join the Midwest ISO.

The Midwest ISO is a regional transmission organization which operates the interconnected transmission system of its members. It administers energy, ancillary services, and financial transmission markets, and controls facilities in all or parts of 13 states and the Canadian province of Manitoba.

In order to join the Midwest ISO, Big Rivers must obtain approval, or consent, from this Commission as well as two of its creditors: the United States government and CoBank ACB. Big Rivers initially proposed to join the Midwest ISO by September 1, 2010. It later amended its proposal by revising the date to join the Midwest ISO to December 1, 2010.[2]

STANDARD OF REVIEW

Big Rivers' proposed transfer of control of its transmission system falls within the purview of KRS 278.218, which requires Commission approval prior to the transfer of ownership or control of a utility's assets with a value of $1,000,000 or greater. The statute provides, in part, that "[t]he commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest."[3] There is no statutory

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[2] Since December 31, 2009, Big Rivers has contracted with the Midwest ISO to receive "backstop" service under Midwest ISO Tariff RR, which provides contingency reserve service during a prospective member's phased integration into the Regional Transmission Organization. Such service is available for a period of time during which the prospective member is actively working toward full integration into the Midwest ISO. In its post-hearing brief, Big Rivers stated that, in order to fully integrate into the Midwest ISO by December 1, 2010, the last integration cycle before the January 1, 2011 expiration of its arrangement under Tariff RR, it required a Commission decision no later than November 1, 2010.

[3] KRS 278.218(2).

definition of "public interest." However, the Commission has interpreted the "public interest" as follows:

> [A]ny party seeking approval of a transfer of control must show that the proposed transfer will not adversely affect the existing level of utility service or rates or that any potentially adverse effects can be avoided through the Commission's imposition of reasonable conditions on the acquiring party. The acquiring party should also demonstrate that the proposed transfer is likely to benefit the public through improved service quality, enhanced service reliability, the availability of additional services, lower rates or a reduction in utility expenses to provide present services. Such benefits, however, need not be immediate or readily quantifiable.[4]

While the application in this case involves the transfer of functional control of utility assets, rather than a transfer of ownership of the assets, the same criteria apply in determining whether the proposed transfer satisfies the "public interest" standard.[5]

OVERVIEW OF THE PROPOSED TRANSFER

Big Rivers seeks to join the Midwest ISO in order to satisfy the requirements of NERC standard BAL-002 regarding contingency reserves. Pursuant to this standard, Big Rivers must be able to balance its supply resources and its system demand within 15 minutes of an event characterized as a "Reportable Disturbance" occurring due to the loss of supply. For Big Rivers, compliance with the standard requires that it maintain contingency reserves sufficient to meet the largest single contingency on its

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[4] Case No. 2002-00018, Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE Aktiengesellschaft and Thames Water Aqua Holdings GmbH (Ky. PSC May 30, 2002) at 7.

[5] Case No. 2002-00475, Application of Kentucky Power Company d/b/a American Electric Power, for Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218 (Ky. PSC Aug. 25, 2003).

system, which would be the loss of its D. B. Wilson Generating Station, which has a maximum capacity of 417 MW.[6]

After extensive research of the potential options for meeting its contingency reserve requirements, Big Rivers determined that joining the Midwest ISO was the only reasonable means currently available that will enable it to satisfy its contingency reserve obligations and avoid potential NERC penalties for non-compliance.[7] Big Rivers avers that joining the Midwest ISO will not only provide it with the reliability benefits inuring from having contingency reserves available in the event of a loss of generation, but will provide additional reliability benefits by providing access to: (1) additional generation resources; (2) Midwest ISO's Security Constrained Economic Dispatch as a means of resolving congestion problems; and (3) Midwest ISO's ability to analyze potential reliability problems across a much larger area than Big Rivers can do as a stand-alone system.

Big Rivers compared the benefits and costs of membership in the Midwest ISO with those of meeting its contingency reserve requirements on a stand-alone, or self-supply, basis. Depending on the assumptions as to the availability of 200 MW of interruptible load from two aluminum smelters served at retail by Kenergy Corp., Big Rivers estimated that joining the Midwest ISO would produce net present value benefits between $32.3 million and $132.8 million over the 2011-2015 period. Big Rivers utilized

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[6] Under the terms of the MCRSG arrangement, Big Rivers was able to comply with the NERC contingency reserve standard with only 32 MW of contingency reserves.

[7] Big Rivers also determined that it was possible to meet its contingency reserve requirements on a stand-alone basis by operating its generating units at reduced capacity levels and relying on its largest industrial customers, two aluminum smelters, for 200 MW of interruptible load, but that this option would be prohibitively expensive and carry a level of reliability risks that was unacceptable.

a five-year period for analyzing costs and benefits since, under the Midwest ISO Transmission Owner's Agreement, a new member is not permitted to withdraw for five years after signing the membership agreement.[8]

STIPULATION AND AGREEMENT

The September 14, 2010 Stipulation reflects the agreement of the parties that Big Rivers' proposal to transfer functional control of its transmission system to the Midwest ISO is for a proper purpose, is consistent with the public interest, and should be approved by the Commission. In addition, the Stipulation contains a commitment by Big Rivers that it will not seek to recover through the Non-FAC Purchase Power Adjustment mechanisms contained in its wholesale power supply contracts either Midwest ISO administrative costs or FERC fees for which it may be obligated. The Stipulation also addresses the means available for Big Rivers to seek recovery of costs related to its membership in the Midwest ISO. Finally, the Stipulation reflects agreement between Big Rivers and KIUC on how they will work together to explore and implement plans for the aluminum smelters to sell demand response service to the Midwest ISO. As clarified at the public hearing, the parties are requesting that the Commission approve only Paragraph Nos. 1 and 2 of the Stipulation, claiming that the other substantive provisions of the Stipulation do not need Commission approval and have been filed

[8] In response to a hearing data request, Item 4, Big Rivers and the Midwest ISO clarified that, since Big Rivers signed its membership agreement in December 2009, it could withdraw as early as December 31, 2014 if proper notice is given.

solely for the purpose of disclosing Big Rivers' commitments to KIUC.[9] Paragraph No. 1 of the Stipulation specifies that the transaction proposed in this case satisfies the requirements of KRS 278.218(2) and should be approved by the Commission, while Paragraph No. 2 specifies that no approval is requested in this case to recover any costs or fees related to Midwest ISO membership through the Non-FAC Purchase Power Adjustment in Big Rivers' wholesale power supply contracts.

DISCUSSION OF ISSUES

Big Rivers presented an analysis of the 2011-2015 costs and benefits of membership in the Midwest ISO. The analysis is uncontroverted, and it shows that at this time membership in the Midwest ISO is Big Rivers' only economically feasible means for complying with NERC's contingency reserve standard. As evidenced by the Stipulation, the Intervenors agree that Big Rivers' proposal to transfer functional control of its transmission system to the Midwest ISO is for a proper purpose, is consistent with the public interest, and should receive Commission approval.

The Commission concurs with the conclusion of the parties that joining the Midwest ISO is the only feasible alternative at this time for Big Rivers to comply with NERC's contingency reserve requirement. While almost any cost-benefit analysis of future events can be subject to debate, Big Rivers' analysis of the period 2011-2015 generally indicates that membership in the Midwest ISO is preferable to meeting its

[9] September 15, 2010 Video Transcript, at 10:18:35. The Commission notes that other provisions of the Stipulation commit Big Rivers to take, or not take, certain actions in connection with future filings at the Commission. Since those provisions have been filed solely for the purpose of disclosure, the Commission will withhold its review of those commitments until future filings are made.

contingency reserve requirements on a stand-alone basis and, for that five-year period, the costs of such membership will not significantly affect its financial condition.

Although the evidence shows that Big Rivers' transfer of functional control of its transmission system to, and its membership in, the Midwest ISO should be approved through 2015, the Commission also recognizes that the longer-term financial implications of membership in the Midwest ISO are uncertain. The evidence presented by KIUC regarding the costs and benefits of such membership through 2025 raise significant concerns with the Commission. KIUC's evidence indicates that, if the transmission projects planned by the Midwest ISO are built, and if the cost allocation methodology proposed by the Midwest ISO is approved by FERC, the net present-value cost to Big Rivers over this longer time period could exceed benefits by $162 million.[10]

We do not know at this time whether FERC will accept the Midwest ISO's recent cost allocation proposal as filed, nor do we know how many of the transmission projects planned by the Midwest ISO will be built. However, the potential for Big Rivers to incur future costs far in excess of benefits raises the question of whether long-term membership in the Midwest ISO is in the best interests of Big Rivers, its three Members, and their retail customers. In recognition of this potential cost, Big Rivers has committed to reviewing the costs and benefits of Midwest ISO membership on a regular basis and communicating the results of its reviews to the Commission.[11] Big Rivers

[10] The proposed cost allocation methodology will be applied to new transmission projects that the Midwest ISO refers to as Multi-Value Projects.

[11] September 15, 2010 Video Transcript, 10:18:35.

also committed to continue to evaluate its options for complying with NERC's contingency reserve requirement.[12]

ANALYSIS AND CONCLUSION

The Commission finds that Big Rivers' request to transfer functional control of its transmission system to the Midwest ISO is for a proper purpose and consistent with the public interest. We find that Big Rivers' membership in the Midwest ISO for the period 2011-2015 is also for a proper purpose and consistent with the public interest. However, while subject to many uncertainties, the evidence presented in this proceeding indicates that longer-term membership in the Midwest ISO could carry substantial financial risks for Big Rivers, its three Members, and their retail customers.

In recognition of these risks, the Commission will impose two conditions on the approval of Big Rivers' request to transfer functional control of its transmission system to the Midwest ISO. The first condition is that Big Rivers file annually with the Commission a report that: (1) evaluates the available options for complying with NERC's contingency reserve requirement; and (2) reviews and analyzes future short-term and long-term costs and benefits of continued membership in the Midwest ISO.[13]

The Commission concurs with the parties that no approval is needed for the provisions of the Stipulation that state how Big Rivers and KIUC will work together to explore the potential for the two aluminum smelters, Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, and other

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[12] Id., 10:25:58.

[13] These reports are to be filed concurrent with Big Rivers' filing of its FERC Form 1 with the Commission, with the first such report to be filed when Big Rivers files its 2011 FERC Form 1. All reports should include a cover letter which specifically refers to this docket number.

industrial customers to sell demand response service to the Midwest ISO. However, before any retail customer can participate in a demand response program sponsored by the Midwest ISO, the customer's participation must be subject to review by the Commission to ensure that the sale is permissible under KRS Chapter 278 and that there is no adverse financial or operational effect on either Big Rivers or its Members. Consequently, the second condition that we impose on this transfer is that any sale of demand response be set forth in a special contract that is filed with the Commission for its review and approval.[14]

FINDINGS AND SUMMARY OF DECISION

Based on the evidence of record and being otherwise advised, the Commission finds that:

1. Big Rivers' request to transfer functional control of its transmission system to the Midwest ISO is for a proper purpose and in the public interest, and should be approved subject to Big Rivers' acceptance of the two conditions specified below and Midwest ISO's acceptance of the one condition specified below relating to participating in demand response programs.

2. Big Rivers should file a report by September 30 of each year describing its current evaluation of available options for complying with NERC's contingency reserve requirement and its review of the short-term and long-term costs and benefits of continued membership in the Midwest ISO.

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[14] This was one of the conditions upon which the Commission accepted a rate case settlement among Kentucky Power Company and the intervenors in Case No. 2005-00341 which provided for customer participation through the utility in the PJM demand response program. See Case No. 2005-00341, General Adjustments of Electric Rates of Kentucky Power Company (Ky. PSC Mar. 13, 2006).

3. No retail customer will be allowed to participate in any Midwest ISO demand response program until that customer has entered into a special contract with its retail electric supplier and Big Rivers, and the special contract has been filed with the Commission for review and approval.

4. That portion of the Stipulation submitted by the parties for Commission approval, specifically, Paragraph Nos. 1 and 2, is reasonable and should be approved.

5. The Chief Executive Officer of Big Rivers should file, within seven days of the date of this Order, a letter accepting and agreeing to be bound by the conditions set forth in Finding Nos. 2 and 3 above.

6. The Chief Executive Officer of the Midwest ISO should file, within seven days of the date of this Order, a letter accepting and agreeing to be bound by the condition set forth in Finding No. 3 above.

7. The approval of Big Rivers' request to join the Midwest ISO will not diminish the Commission's authority to review and set Big Rivers' electric rates based on the value of its property used to provide electric service.

8. The approval of Big Rivers' request to join the Midwest ISO will not diminish Big Rivers' existing obligation to:

a. Regularly file for Commission review an integrated resource plan detailing Big Rivers' load, determining appropriate reserve requirements, and identifying sources of energy, demand-side resources, and projected need for new generation and transmission facilities.

b. Provide regulated service to its Members through the provision of bundled generation and transmission electric service.

c. File for a certificate of public convenience and necessity prior to commencing construction of an electric generation facility or transmission facility.

IT IS THEREFORE ORDERED that:

1. Big Rivers' request to transfer functional control of its transmission system to the Midwest ISO is approved subject to the filing within seven days of the date of this Order of the written acknowledgements described in Finding Nos. 5 and 6 above.

2. The provisions of Paragraph Nos. 1 and 2 of the Stipulation submitted by the parties are approved.

3. Any retail customer electing to participate in a Midwest ISO demand response program shall comply with the procedures set forth in Finding No. 3 above.

4. Any documents filed in the future pursuant to Finding No. 2 herein shall reference this case number and shall be retained in the utility's general correspondence file.

By the Commission

ENTERED
NOV - 1 2010
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

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September 14, 2010

RECEIVED
SEP 14 2010
PUBLIC SERVICE COMMISSION

Via Federal Express

Jeff DeRouen
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of Its Transmission System to Midwest Independent Transmission System Operator, Inc., PSC Case No. 2010-00043

Dear Mr. DeRouen:

Enclosed for filing in this case on behalf of Big Rivers Electric Corporation ("Big Rivers") is the supplemental testimony of C. William Blackburn. Mr. Blackburn's supplemental testimony presents and explains the "Stipulation and Agreement" signed by the parties, which is attached as an Exhibit CWB Supplemental-1 to his supplemental testimony. The Stipulation and Agreement settles the issues between and among the parties in this matter, and is presented for approval by the Public Service Commission. The original signature pages of counsel for the Attorney General, Kentucky Industrial Utility Customers Inc. and Midwest Independent Transmission System Operators, Inc., will be filed Wednesday, September 15, 2010. I certify that a copy of this letter and enclosures has been served on each party on the attached service list.

Sincerely yours,

James M Miller

James M. Miller

JMM/ej
Enclosures

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric	)	
Corporation for Approval to Transfer	)	
Functional Control of Its Transmission	)	CASE NO. 2010-00043
System to Midwest Independent	)	
Transmission System Operator, Inc.	)	

SUPPLEMENTAL TESTIMONY OF C. WILLIAM BLACKBURN
IN SUPPORT OF STIPULATION AND AGREEMENT
September 13, 2010

Q. Please state your name and position.

A. My name is C. William Blackburn. I am the Big Rivers Electric Corporation ("Big Rivers") Senior Vice President Financial and Energy Services and Chief Financial Officer. I am the same C. William Blackburn who filed testimony attached as Exhibit 3 to the Application in this matter.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to introduce a document titled "Stipulation and Agreement," by which the parties in this case have reached agreement on the fundamental issue presented by Big Rivers' Application, and have made certain mutual agreements on other matters. I will also describe briefly the process by which the Stipulation and Agreement was negotiated. The purposes of the Stipulation and Agreement are to demonstrate to the Public

Service Commission ("Commission") that the parties do not oppose Big Rivers' membership in the Midwest ISO, and to avoid a protracted hearing in this case.

Q What was your role in the negotiation of the Stipulation and Settlement?

A. I have been involved on behalf of Big Rivers in all of the business negotiations regarding the Stipulation and Agreement.

Q. Please describe how the Stipulation and Agreement came to be.

A. Big Rivers has been unequivocal in its dealings with the Midwest ISO, and in numerous statements made in the Application, pleadings and responses to information requests in this proceeding, that Big Rivers proposes to transfer functional control of its transmission system to the Midwest ISO, and to become a member of the Midwest ISO, principally to resolve its regulatory and operational needs to have Contingency Reserve Service to operate its system in accordance with NERC's Contingency Reserve rules. Joining the Midwest ISO has the potential to be quite expensive, although, as the testimony shows, there could also be considerable offsetting benefits to Midwest ISO membership. So Big Rivers, its members and the energy-intense aluminum companies ("Smelters") who are affected by Big Rivers' costs have conducted an exhaustive search for a way to satisfy Big Rivers' Contingency Reserve requirement by an alternate means.

Prior to the filing of the Application, and over the course of this proceeding, Big Rivers and the Smelters met on several occasions to discuss options to address the Contingency Reserve issue. The most recent meeting occurred on August 19, 2010, with representatives of KIUC, including the Smelters. At that meeting all parties agreed that there is no reasonable alternative to Midwest ISO membership to solve Big Rivers' Contingency Reserve requirement on a timely basis. During that meeting and subsequently, Big Rivers and KIUC have discussed issues that Big Rivers' Midwest ISO membership raises for the KIUC, potential opportunities created by that membership and how Big Rivers might give some comfort regarding issues that concern KIUC, including the Smelters. The results of those discussions, which concluded on September 10, 2010, are memorialized in the terms of the Stipulation and Agreement attached to this supplemental testimony as Exhibit CWB Supplemental 1. Subsequent to Big Rivers and KIUC reaching agreement, the draft Stipulation and Agreement was submitted to the Attorney General and the Midwest ISO, the other parties in this proceeding, who have now signed the Stipulation and Agreement.

Q. Have the parties to the Stipulation and Agreement recommended that the Commission authorize Big Rivers to transfer functional control of its transmission system to the Midwest ISO, as Big Rivers requested in the Application?

A. Yes. In paragraph number 1 of the Stipulation and Agreement, the parties agree that the Commission should approve Big Rivers transferring functional control of its transmission system to the Midwest ISO in accordance with the statutory requirements under which the Application was filed by Big Rivers.

Q. Which paragraphs of the Stipulation and Agreement contain the substantive agreements between Big Rivers and KIUC?

A. Paragraphs 2, 3, 4 and 5 of the Stipulation and Agreement contain what could be considered the substantive agreements reached between Big Rivers and KIUC.

Q. Please explain the nature of the agreements found in paragraph numbers 2 and 3 of the Stipulation and Agreement.

A. In response to Commission Staff Information Request 1-17, and KIUC Data Request 2-13, Big Rivers expressed the view that it could flow certain Midwest ISO costs through the Purchase Power Adjustment mechanisms in the wholesale power supply contracts related to smelter retail service, known as the Non-FAC PPA, and the Purchase Power regulatory asset authorized by the Commission in its March 6, 2009 Order in Case No. 2007-00455, also known as the Big Rivers "unwind transaction" case. Big Rivers' subsequent research disclosed that FERC accounting requires that those costs be accounted for in accounts that are different from the accounts incorporated in those Purchase Power Adjustment mechanisms. To allay KIUC's concerns that Big Rivers was still considering using the Non-FAC PPA to recover Midwest ISO administrative costs or FERC fees, and to clarify the record in this case as to Big Rivers' intentions, Big Rivers agreed to paragraph numbers 2 and 3 of the Stipulation and Agreement.

Q. Are there other agreements in the Stipulation and Agreement related to how Big Rivers will seek to recover the costs incurred by it as a member of the Midwest ISO?

A. Yes. In paragraph number 4 of the Stipulation and Agreement, Big Rivers agrees to seek amendment of the wholesale power supply contracts related to smelter service to exclude from the contractual Tier Adjustment Charge contained in Section 4.7 of those wholesale power agreements all costs allocated to Big Rivers under the Midwest ISO Transmission Expansion Plan, which is usually referred to as "MTEP." Big Rivers views these costs as system costs which should, in the future, be allocated among all classes of Big Rivers' ratepayers. Without the contract amendments, the Smelters could be required to pay 100% of those costs under the Tier Adjustment Charge, to the extent that the Tier Adjustment Charge is below the ceiling imposed in the contracts.

Q. What agreements are contained in the Stipulation and Agreement relating to opportunities created by Midwest ISO membership?

A. As the Commission knows, one of the alternatives considered by Big Rivers as a potential element of a plan to satisfy its NERC Contingency Reserve requirement is to incorporate up to 320 megawatts of power committed to the Smelters under the Smelter-related wholesale power contracts that the Smelters thought they could make available on an interruptible basis. While no viable, comprehensive plan incorporating smelter interruptible power could be achieved, Midwest ISO membership may present an opportunity to take advantage of the Smelters' ability and willingness to interrupt a portion of their smelting process and thereby curtail their respective loads for a brief period. Big Rivers has agreed, as provided in paragraph number 5, to work with the Smelters to explore and implement plans for the Smelters to sell demand response service, and perhaps provide back-up service that would allow Big Rivers to sell its spinning reserves. At this point we have done little more than identify these subjects for investigation, and do not know what physical, contractual, legal or regulatory issues might need to be solved to make either of these concepts a reality. Big Rivers' commitment is to work with the Smelters to see if either of these ideas is viable, and can be accomplished without detriment to Big Rivers or its members. Big Rivers has also agreed to investigate whether the demand response arrangements can be feasibly extended to the Large Industrial customers on its member's systems.

Q. Are there any other substantive agreements in the Stipulation and Agreement?

A. No. Paragraph No. 6 was added to clarify that nothing in the Stipulation and Agreement is intended to constitute a waiver by Big Rivers of its rate options for recovery of Midwest ISO costs, except as expressly provided in the Stipulation and Agreement, and that the other parties to the Stipulation and Agreement are not waiving their rights to object to the lawfulness or reasonableness of any rate methodology Big Rivers may propose to collect those costs. But that paragraph just states what the parties believe is the case in any event.

Q. Please explain the purpose of paragraph number 7 of the Stipulation and Agreement.

A. This paragraph explains that the agreement of the parties to this Stipulation and Agreement is conditioned upon the Stipulation and Agreement being approved by the Commission without material change or condition unacceptable to any affected party. The paragraph then sets forth a resolution mechanism for dealing with any material change or condition imposed by the Commission that is unacceptable to an affected party. The purpose of this paragraph is to make sure each party gets the benefit of its bargain, and to give the parties a procedure by which they can attempt to restructure their agreement if the Commission does not accept the Stipulation and Agreement as proposed.

Q. Please explain the purpose of paragraph number 8 of the Stipulation and Agreement.

A. Our understanding is that the Commission requires that all agreements of a party in connection with the settlement be included in the settlement agreement. The settlement of the issues presented to the Commission for decision in this case is contained in Paragraphs 1 and 2 of the Stipulation and Agreement. Paragraphs 3 through 5 of the Stipulation and Agreement contain other substantive agreements between or among two or more of the parties that are collateral to the issues presented to the Commission by Big Rivers in its Application, but are included for purposes of full disclosure. By "collateral," I mean that the issues on which the parties reached agreement in Paragraphs 3 through 5 of the Stipulation and Agreement are not presented to the Commission for decision in this case, and do not have to be resolved by the Commission to decide the issue of whether Big Rivers should be permitted to transfer functional control of its transmission system to the Midwest ISO. Even if the Commission does not approve the Stipulation and Agreement as a part of this case, so long as Big Rivers transfers functional control of its transmission system to the Midwest ISO under authority granted by the Commission in this case, all the agreements in this Stipulation and Agreement will still be enforceable contractual obligations of the Parties.

Q. Should the Stipulation and Agreement be accepted and approved by the Public Service Commission?

A. Yes. Paragraphs 1 and 2 of the Stipulation and Agreement contain the well-informed conclusions of the parties that the relief requested by Big Rivers in the Application should be granted. The contractual agreements between and among the parties in Paragraphs 3 through 5 incorporate concepts the parties have discussed relating to how they will deal with collateral issues raised by Big Rivers' anticipated membership in the Midwest ISO. Big Rivers believes that its obligations in those agreements are reasonable. It was under no compulsion to make any of those agreements. Big Rivers urges the Commission to accept the Stipulation and Agreement, and make the Stipulation and Agreement a part of its order in this matter.

Q. Does this conclude your supplemental testimony?

A. Yes.

VERIFICATION

I verify, state, 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.

C. William Blackburn

C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 13th day of September, 2010.

Vikki G. King

Notary Public, Ky. State at Large
My Commission Expires 03-03-2014

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

STIPULATION AND AGREEMENT

Applicant, Big Rivers Electric Corporation ("Big Rivers"), and intervenors Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), Kentucky Industrial Utility Customers, Inc. ("KIUC") and the Attorney General of the Commonwealth of Kentucky ("Attorney General"), Big Rivers, Midwest ISO, KIUC and the Attorney General being all the parties to this proceeding (each, a "Party," and collectively, the "Parties"), stipulate and agree as follows pursuant to 807 K.A.R. 5:001, Section 4(6):

1. The proposal of Big Rivers to transfer functional control of its transmission system to Midwest ISO is for a proper purpose and consistent with the public interest under KRS 278.218(2), and should be approved by the Public Service Commission ("Commission").

2. Big Rivers' application in this proceeding does not seek authorization from the Commission to recover any Midwest ISO administrative costs or Federal Energy Regulatory Commission

("FERC") fees, for which it becomes obligated (currently charged under Schedules 10, 16 and 17 to the Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Midwest ISO Tariff")), through the Non-FAC Purchased Power Adjustment mechanisms in its wholesale power supply contracts.

3. Big Rivers will not attempt to recover any Midwest ISO administrative costs or FERC fees, for which it becomes obligated (currently charged under Schedules 10, 16 and 17 to the Midwest ISO Tariff), through the Non-FAC Purchased Power Adjustment mechanisms in its wholesale power supply contracts.

4. Big Rivers and KIUC, on behalf of Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century," and Alcan and Century collectively, the "Smelters"), agree that Big Rivers agrees to amend the July 16, 2009 Smelter-related wholesale power agreements with Kenergy Corp. to exclude from the contractual Tier Adjustment Charge contained in Section 4.7 of those wholesale power agreements all costs allocated to Big Rivers under the Midwest ISO Transmission Expansion Plan ("MTEP")(currently charged under Midwest ISO Schedule 26), and agrees to seek approval of such amendments. Such amendments shall become effective with the effective date of the order of the Commission in the next general base rate case filed by Big Rivers. In

that rate case or in any other proceeding, Big Rivers will propose to allocate MTEP costs as a system cost among all classes of Big Rivers' ratepayers: Rural, Large Industrial and Smelter.

5. Big Rivers agrees with KIUC that Big Rivers will work with Century and Alcan to explore and implement plans for the Smelters to sell demand response service (including regulation service) to Midwest ISO, and for Big Rivers to sell its spinning reserves into the Midwest ISO ancillary services market with the Smelters providing back-up through curtailment of their respective loads, provided that (i) Big Rivers is not required to assist with or agree to any such arrangements that may adversely affect Big Rivers' or its members' operations, finances or existing contractual relationships, and (ii) any such arrangements must receive all necessary regulatory, creditor and other approvals. Subject to those approvals, such arrangements may be directly with Midwest ISO or with Big Rivers acting as agent. Big Rivers shall be given a reasonable opportunity to participate in any discussions between the Smelters and Midwest ISO regarding such arrangements. Big Rivers agrees with KIUC that Big Rivers will work with its members' Large Industrial Customers to explore and implement plans for similar demand response arrangements, provided that (i) Big Rivers is not required to assist with or agree to any such arrangements that may adversely affect Big Rivers' or its members'

operations, finances or existing contractual relationships, and (ii) any such arrangements must receive all necessary regulatory, creditor and other approvals.

6. This Stipulation and Agreement shall not be construed to limit the rate methodology by which Big Rivers may seek to recover Midwest ISO administrative costs, FERC fees, MTEP costs or any other costs related to its Midwest ISO membership, or the schedule by which Big Rivers may seek to recover those costs except as expressly provided for in paragraphs 2, 3 and 4 of this Stipulation and Agreement; provided, however, that no other Party shall have waived its right to object to any such rate methodology as being unlawful or unreasonable. Moreover, the Attorney General strongly opposes any surcharge not expressly authorized by statute or case law, and nothing in this Stipulation and Agreement shall be interpreted as the Attorney General's acquiescence to any type of rate recovery not expressly authorized by statute or case law.

7. This Stipulation and Agreement is subject to the approval of the Commission without material change or condition unacceptable to any affected Party. In the event the Commission requires a material change to this Stipulation and Agreement or imposes material conditions in its order approving the Stipulation and Agreement, which change or condition is not acceptable to an affected Party, the Parties

agree to confer within five (5) business days of the date of the Commission order and attempt to negotiate in good faith an alteration acceptable to the Commission and to all Parties resolving the required change or condition. If the Parties cannot resolve the required change or condition in a manner acceptable to the Commission, then the affected Party may seek rehearing or appeal of the required condition or change.

8. This Stipulation and Agreement shall not be construed to divest the Commission of jurisdiction under KRS Chapter 278. The only acceptance, approval or authorization sought from the Commission by the Parties is with respect to paragraphs 1 and 2 of this Stipulation and Agreement. If Big Rivers transfers functional control of its transmission system to the Midwest ISO as a result of an order entered by the Commission in this proceeding, then even if this Stipulation and Agreement is not approved by the Commission, all agreements between or among the Parties contained herein shall constitute the enforceable contractual obligations of the Parties.

9. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation and Agreement be accepted and approved without conditions other than as contained in this Stipulation and Agreement. The Parties will not appeal or seek rehearing of findings by the Commission in an order in

this proceeding that the proposal of Big Rivers to transfer functional control of its transmission system to Midwest ISO is for a proper purpose and consistent with the public interest, and is approved. Each signatory waives all cross-examination of the other Parties' witnesses, except the witness offered by Big Rivers to support the Stipulation and Agreement.

10. Each signatory to this Stipulation and Agreement has consulted with his or her respective client or clients regarding the terms of this Stipulation and Agreement, and has been duly authorized to sign this Stipulation and Agreement on behalf of that client or clients. KIUC represents that Alcan and Century have read and agreed to the terms and conditions of this Stipulation and Agreement.

11. This Stipulation and Agreement shall be filed with the Commission on or before the hearing in this matter scheduled to commence on September 15, 2010.

12. The agreements between or among the Parties in this Stipulation and Agreement represent all the agreements between or among the Parties on the subjects covered by this Stipulation and Agreement, and cannot be amended except in writing, signed by all the Parties.

STIPULATED AND AGREED, as of this __ day of September, 2010:

Counsel for Big Rivers

Counsel for Midwest ISO

Counsel for KIUC

Counsel for the Attorney General

Counsel for Big Rivers

Counsel for Midwest ISO

Counsel for KIUC

Counsel for the Attorney General

Counsel for Big Rivers

Counsel for Midwest ISO

Counsel for KIUC

Counsel for the Attorney General

Counsel for Big Rivers

Counsel for Midwest ISO

Counsel for KIUC

Counsel for the Attorney General